Document 23

From: Harker Steele, Amanda J.
Sent: Mon, 31 Jul 2023 17:48:34 +0000
To: Easley, Kevin; Skone, Timothy
Cc: Curry, Thomas; Robert Wallace; Singh, Hartej (CONTR); Adder, Justin (NETL); Bostick, Odysseus
Subject: Notes from Today's Meeting - Touch Point
Attachments: Draft_Env.Review_Task4_LNG_LNGRegAnalysisSupport_FWP-DraftPreDecisional_7_28_23.docx, Draft_Env.Review_Task4_LNG_LNGRegAnalysisSupport_FWP-DraftPreDecisional_7_28_23.docx

Hi Kevin and Tim,

Thank you for taking the time today to walk us through the comments on the Draft Env. Review.

We are very happy that the work we did to update the report pushed this back on the right track and we look forward to getting the next iteration over to you.

We are currently targeting a delivery date of August 11th for the next revision but we will 1) need to confirm with our tech editor that the schedule we have in mind will work and 2) want to walk through the comments on Chapter 7 before nailing down the date.

I've attached the notes from today's meeting, along with my additions/notes on the comments we walked through on the report – Chapters 1-3 this morning. We will add comments from the two upcoming meetings this week to the same documents but I wanted to share for reference.

Please let me know if I missed anything. Thanks all!

Sincerely,
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POTENTIAL ENVIRONMENTAL IMPACTS ASSOCIATED WITH UNCONVENTIONAL NATURAL GAS

Commented [TC1]: Global comment: is the EJ chapter consistent with the frame of "environmental impacts"? Should the title and introduction be "environmental and community impacts"? I'd like feedback from Kelli, Natenna, and Odysseus on this.

Commented [ST2R1]: Guidance to NETL: We are interested in your thoughts if the title is still accurate or should be changed to reflect that the addition of EJ and that the natural gas sections discuss both unconventional and conventional gas production.

July 21, 2023

DOE/NETL-2023/4388

DRAFT DELIBERATIVE PRE-DECISIONAL

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Disclaimer

Hartej Singh[2]: *Writing – Original Draft;* ***Michael Marquis***[2]: *Writing – Original Draft;* ***Odysseus Bostick***[2]: *Writing – Original Draft;* ***Robert Wallace***[2]: *Writing – Original Draft;* ***Amanda Harker Steele***[1*]: *Writing – Review & Editing, Supervision*

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Commented [ST3]: Header text needs to fit on one line.

The authors wish to acknowledge the excellent guidance, contributions, and cooperation of the NETL staff, particularly:

Commented [HSAJ4]: Comment for FE/HQ: We will update accordingly for final draft to reflect contributions.

Commented [STSR4]: Understood - thank you.

Suggested Citation:
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LIST OF EXHIBITS

ACRONYMS AND ABBREVIATIONS

AEO	Annual Energy Outlook
API	American Petroleum Institute
AR5	IPCC Fifth Assessment Report
B	Billion
Bcf	Billion cubic feet
BLM	Bureau of Land Management
BTEX	Benzene, toluene, ethylbenzene, xylenes
Btu	British thermal unit
CBM	Coalbed methane
CH_4	Methane
CMSC	Citizens Marcellus Shale Coalition
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_2e, CO_2-eq	Carbon dioxide equivalent
COGCC	Colorado Oil and Gas Conservation Commission
CRS	Congressional Research Service
d	Day
DOE	Department of Energy
DOI	Department of the Interior
EIA	Energy Information Administration
EDP	Exploration, development, and production
EPA	Environmental Protection Agency
FECM	Office of Fossil Energy and Carbon Management
FERC	Federal Energy Regulatory Commission
FP	Flowback and produced (water)
ft, FT	Foot
g	Gram
G&B	Gathering and boosting
gal	Gallon
GAO	Government Accountability Office
GHG	Greenhouse gas
GHGI	Greenhouse Gas Inventory
GHGRP	Greenhouse Gas Reporting Program
GWP	Global warming potential
H_2S	Hydrogen sulfide
HAP	Hazardous air pollutant
HPh	Horsepower-hour
IPCC	Intergovernmental Panel on Climate Change
kg	Kilogram
kJ	Kilojoule
km	Kilometer
km^2	Square kilometers
kWh	Kilowatt hour
LCA	Life cycle analysis
LNG	Liquefied natural gas
m^2	Square meter
m^3	Cubic meter
Mcf, MCF	Thousand cubic feet
min	Minute
MIT	Massachusetts Institute of Technology
MJ	Megajoule
MM	Million
MWh	Megawatt hour
N_2O	Nitrous oxide
NEIC	National Earthquake Information Center
NETL	National Energy Technology Laboratory
NGL	Natural gas liquid
NOAA	National Oceanic and Atmospheric Administration
NORM	Naturally occurring radioactive material
NOx	Nitrogen oxides
NPS	National Park Service
NSPS	New Source Performance Standards
NYSDEC	New York State Department of Environmental Conservation
O_2	Oxygen
OAC	Ohio Administrative Code
ONE Future	Our Nation's Energy Future
ORC	Ohio Revised Code
OSF	Oral slope factor
PA	Pennsylvania

PADEP	Pennsylvania Department of Environmental Protection
PM	Particulate matter
PRV	Pressure release valve
REC	Reduced emission completion
RFF	Resources for the Future
RfV	Reference value
RRC	Railroad Commission of Texas
scf	Standard cubic foot
SDWA	Safe Drinking Water Act
SF_6	Sulfur hexafluoride
SO_2	Sulfur dioxide
T	Trillion
T-D, T&D	Transmission and distribution
T&S	Transport and storage
Tcf	Trillion cubic feet
tCO_2	tonnes carbon dioxide
TexNet	Texas' Center for Integrated Seismicity Research
t NG	tonnes natural gas
Tg	Teragram
tonne	Metric ton
U.S.	United States
UIC	Underground Injection Control
USFS	U.S. Forest Service
USGS	U.S. Geological Survey
VOC	Volatile organic compound
WV	West Virginia
yr	Year

1 INTRODUCTION

The United States (U.S.) Department of Energy's (DOE) Natural Gas Regulatory Program is responsible for ~~granting authorizations~~reviewing applications to import and/or export natural gas from and/or to foreign countries. An important dimension ~~of~~ in considering whether to grant such authorizations is how the additional natural gas production and transport activities needed to support proposed actions ~~these exports and/or imports~~ may impact the environment. ~~As such~~Accordingly, ~~these~~ potential impacts are factors affecting the public'~~s~~ interest.[a]

Although fundamental uncertainties exist regarding the exact amount and location of natural gas production or transportation that would occur in response to additional authorizations being granted, it is important that DOE acknowledge and provide the public and decision-makers with access to updated information regarding the potential environmental consequences associated with such activities. Accordingly, DOE has prepared this update to the 2014 Addendum to Environmental Review Documents Concerning Exports of Natural Gas from the United States (hereafter the 2014 Addendum) to provide the public with an improved understanding of the potential environmental impacts associated with such activities (DOE, 2014).

We cannot estimate with certainty where, when, or by what method any additional natural gas would be produced, consumed, or exported in response to the granting of authorizations to import and/or export natural gas. Therefore, DOE cannot meaningfully analyze the specific environmental impacts associated with such activities. ~~As such, similar to~~Therefore, as with the 2014 Addendum, this report provides only a review of ~~the profusion of~~ peer-reviewed, scientific literature ~~produced~~ related to the potential environmental consequences of expanding natural gas production and related activities.

As unconventional natural gas production has represented an ever-growing share of U.S. natural gas production, the environmental impacts reviewed in this report relate primarily to those associated with unconventional production activities. The publications referenced build on a strong body of existing literature that traces the evolution of unconventional natural gas production techniques from their conceptual stages in the 1970s~~,~~ to the technology advancements that contributed to the shale gas boom of the early 2000s, as well as ~~and~~ further development of additional unconventional resources, including tight gas sands and coalbed methane (CBM) resources to the export of liquefied natural gas (LNG).

This report attempts~~makes every attempt~~ to summarize the published descriptions of the potential environmental impacts of ~~unconventional~~ natural gas ~~upstream~~ operations within the lower 48 states as detailed by government, industry, academia, scientific, non-governmental, and citizen organizations. The sources cited are all publicly available documents. While this

[a] DOE is responsible for considering the environmental impact of its decisions on applications to export natural gas, including liquefied natural gas (LNG), to countries with which the United States has not entered into a free trade agreement (FTA) requiring national treatment for trade in natural gas. (Applications for trade with FTA countries are deemed to be in the public interest by statute.) DOE conducts environmental reviews under the National Environmental Policy Act (NEPA) and as part of its public interest review under the Natural Gas Act (NGA).

Commented [TC6]: @Lavoie, Brian D. should we specify that this is for authorizations to non-FTA countries or is the use of this document broader to include all authorizations?

Commented [LBD7R6]: It's correct that this would only be used for non-FTA applications. (FTA applications are not subject to DOE NEPA review.) I'd suggest maybe just a footnote on this (see my suggestion), so as not to distract the reader at this early point. (Amy/Jen - please jump in if you have a different view.)

Commented [ST8R6]: Guidance to NETL: Add Brian's suggested footnote.

Commented [LBD9]: Suggest consider "may" and similar language that reflects uncertainties about impacts.

Commented [LBD10]: @Easley, Kevin do you suggest in-text treatment of this point vs. the footnote? I think it should be one or the other.

Commented [EK11R10]: I don't have a preference. But my sense is not everyone reading this Addendum will know what exactly goes into / governs a DOE 'public interest determination.' I defer to you and @Sweeney, Amy, @Lavoie, Brian D.

Commented [LBD12]: "such activities" near the end of this passage, at least textually as written, refers to "both conventional and unconventional natural gas markets" earlier in the passage. Suggest clarify to focus on unconventional, which is the topic of this report.

Commented [HSAJ13R12]: Done

report by no means represents an exhaustive list of the sources that discuss environmental consequences of upstream natural gas activities, the sources cited are ~~assumed~~ believed to be representative, and no significant areas have been excluded from the report. Multiple publications on similar topics are compared based only on their technical and methodological distinctions. Over the past decade, the focus of environmental issues has evolved with some interest in the public literature varying over time. Key research in some areas remains the same with minor to no new additions to the basis of scientific knowledge, in this situation some historical references have been maintained. No opinion on or endorsement of these works is intended or implied.

This report is divided into chapters, each of which contains a separate section of references so that each type of environmental impact can be explored further. The types of environmental impacts that are documented in this review include the following:

- Greenhouse gas (GHG) emissions and climate change (Chapter 2)
- Air quality (Chapter 3)
- Water use and quality (Chapter 4)
- Induced seismicity (Chapter 5)
- Land use and development (Chapter 6)
- Environmental and social justice (Chapter 7)

In addition to containing information on potential environmental impacts, this report provides some background information on domestic natural gas production.

1.1 Natural Gas Basics

Natural gas is an odorless, gaseous mixture of hydrocarbons, largely made up of methane (CH_4) but also containing small amounts of natural gas liquids (NGLs) and nonhydrocarbon gases (e.g., carbon dioxide [CO_2] and water vapor) (EIA, 2023b). Natural gas is one of the major combustion fuels used throughout the country. It is mainly used to generate industrial and utility electric power, produce industrial process steam and heat, and heat residential and commercial spaces. The average gross heating value of natural gas is approximately 1,020 British thermal units per standard cubic foot (Btu/scf), usually varying from 950 to 1,050 Btu/scf.

Natural gas is typically classified as being either conventional or unconventional, depending on the permeability of the formation within which it is found, the production technology used to secure it, the current economic environment, and the scale, frequency, and duration of production from the resource (EIA, 2023b; Krieg, 2018).

Generally, conventional natural gas refers to natural gas found in highly permeable reservoirs, typically composed of sandstone or limestone, which allows for extraction to be completed in a relatively straightforward manner via vertical rather than horizontal drilling. Unconventional natural gas refers to natural gas found within low-permeab~~ityle~~ility reservoirs; it is generally trapped within the pores (i.e., small, unconnected spaces) of rocks, which makes extraction

Commented [LBD14]: Can something be said like that the authors believe this survey is representative and no significant areas have been excluded from this review?

Commented [HSAJ15R14]: Done

Commented [ST16]: The HHV of natural gas used in the LCA work is 1,031 Btu/scf (54.1 MJ/kg) [60 deg F, 1 atm]. You need to specify HHV or LHV and at what standard conditions you are reporting. My understanding is that the oil & gas industry uses 60F / 1atm as the definition of "standard" conditions, while the industrial gas industry prefers 70F / 1atm.

Commented [HSAJ17R16]: Ask Harsh and Matt and simply adjust sentence to reflect.

more difficult and necessitates advanced drilling (e.g., directional or horizontal drilling) and well stimulation (e.g., hydraulic fracturing) techniques that are energy intensive (BP, 2017).

Innovations in existing oil and gas exploration and production technologies have revolutionized unconventional natural gas production in the United States. The production of natural gas from ~~U~~unconventional ~~natural gas~~ resources has not only ~~make~~ made up for declining conventional natural gas production but has~~ve~~ also led to new levels of natural gas supply in the United States. This increased supply has contributed to an increase in the use of natural gas for power generation, manufacturing, transportation, and residential and commercial heating, as well as the ~~amount~~ availability of natural gas ~~being exported~~ for export from the United States.

There are three primary types of unconventional natural gas:[a]

- **Shale Gas:** refers to natural gas found within shale rock formations, which consist of fine-grained sedimentary rock that forms when silt and clay-size mineral particles are compacted together (Zendehboudi and Bahadori, 2017). Shale rock formations can be easily broken into thinner, parallel layers of rock. ~~Black shale, a dark-colored type of sedimentary shale rock containing organic-rich material, is also a source rock for unconventional natural gas (Ohkouchi, Kuroda, and Taira, 2015).~~
- **CBM:** refers to natural gas that is both generated and stored in coal beds. Originally extracted from coal mines to reduce the potential for explosions caused by an excess of CH_4 gas within the mine and subsequently disposed of, CBM now serves as an important source of energy. ~~Sequestering~~ Producing CBM from deeper, denser coal formations often requires the use of hydraulic fracturing technology.
- **Tight Sands Gas:** refers to natural gas found in low-permeability, gas-bearing, fine-grained sandstones, or carbonates.

Shale rock formations can contain significant accumulations of natural gas and/or oil. These formations are often referred to as "plays" and can be found in nearly 30 U.S. states. Operators in ~~T~~the Barnett Shale formation, which is located in Texas and is one of the largest onshore natural gas ~~fields~~plays in the United States, have~~s~~ been producing unconventional natural gas since the early 2000s (RRC, 2023). ~~It is one of the largest onshore natural gas fields in the United States.~~ While operators in the Barnett Shale formation still produce~~s~~ a significant amount of unconventional natural gas, the Marcellus Shale formation—located in the Appalachian Region of the United States and spanning Ohio, Pennsylvania, and West Virginia—is currently the largest ~~producer~~ source of unconventional natural gas from shale (EIA, 2023b).

Primary enabling technologies for accessing unconventional natural gas include hydraulic fracturing and horizontal drilling. Hydraulic fracturing (sometimes referred to as hydrofracking or simply fracking) is the process of pumping water mixed with a small amount of sand and other chemical additives (i.e., fracturing fluid) underground through a wellbore at a pressure

Commented [ST18]: NETL: we added this text for clarity. Is it still appropriate to reference BP, 2017? Please confirm.

Commented [HSAJ19R18]: Does the new text impact the accuracy of the reference to BP 2017 or do we need to add an additional reference or move the BP reference.?

Commented [LBD20]: Should increasing exports be mentioned here, for completeness?

Commented [HSAJ21R20]: Adjusted

[a] There are other types of unconventional natural gas whose exploitation has not yet reached commercial scale. These include methane hydrate, which is a crystalline solid that consists of a methane molecule surrounded by a cage of interlocking water molecules. Methane hydrate is an "ice" that only occurs naturally in subsurface deposits where temperature and pressure conditions are favorable for its formation.

that is sufficient to cause a target rock formation to break (i.e., fracture) (USGS, 2019).[c] As the rock is fractured, natural gas that would have otherwise remained trapped is able to be released into a wellbore and returned to the surface (USGS, 2019).

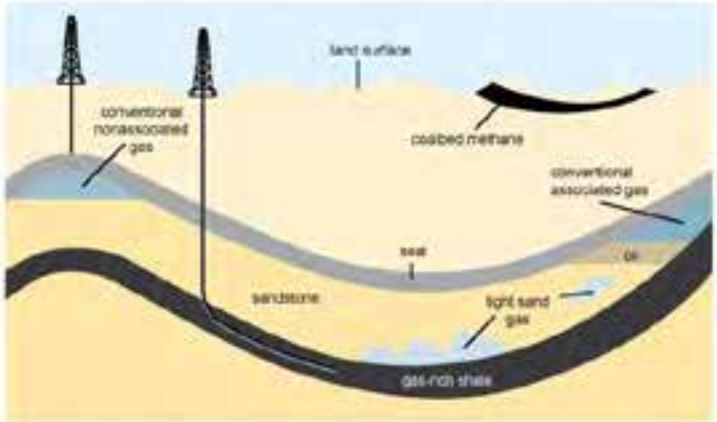
The i~~I~~nternal pressure caused by the fracturing of the rock formation also releases fluid, which travels to the surface through the wellbore. This fluid is commonly referred to as "flowback" or "produced water" and may contain the injected chemicals in addition to any naturally occurring materials found below the surface (e.g., brines, metals, radionuclides, and hydrocarbons). The fluid is typically stored on site in tanks or pits before it is treated and disposed of or recycled. In many cases, disposing of the fluid involves injecting it underground. In areas where underground injection is not an option, the fluid can either be reused or processed by a wastewater treatment facility and subsequently discharged into surface water.

Hydraulic fracturing has been applied since the late 1940s when Standard Oil of Indiana (later known as Amoco) developed the technique and performed some of the first fracture treatments in the Hugoton Gas Field in Kansas (BP, 2017). While the use of hydraulic fracturing is not limited ~~only~~ to wells that are horizontally drilled, the combination of horizontal drilling and hydraulic fracturing has increased the volume of domestic natural gas considered to be "technically recoverable" (i.e., able to be produced using currently available technology and industry practices regardless of any economic considerations).

The process of horizontal drilling involves first drilling a vertical well. Once a certain depth has been reached with the vertical well, the path of drilling is bent until the well begins to extend horizontally. Horizontal wells are not only longer than vertical wells, but the process is much more complex. ~~As such, a~~A horizontal well is therefore generally more expensive to drill than a vertical well, but it is expected to produce more natural gas (EIA, 2018). The horizontal section, sometimes referred to as ~~or~~ directionally drilled section,~~n~~ of a well can extend thousands of feet (ft). Exhibit 1-1 provides a schematic of conventional natural gas and the various types of unconventional natural gas resources described previously (EIA, 2023b). Exhibit 1-2 provides a schematic of the hydraulic fracturing process (BP, 2017).

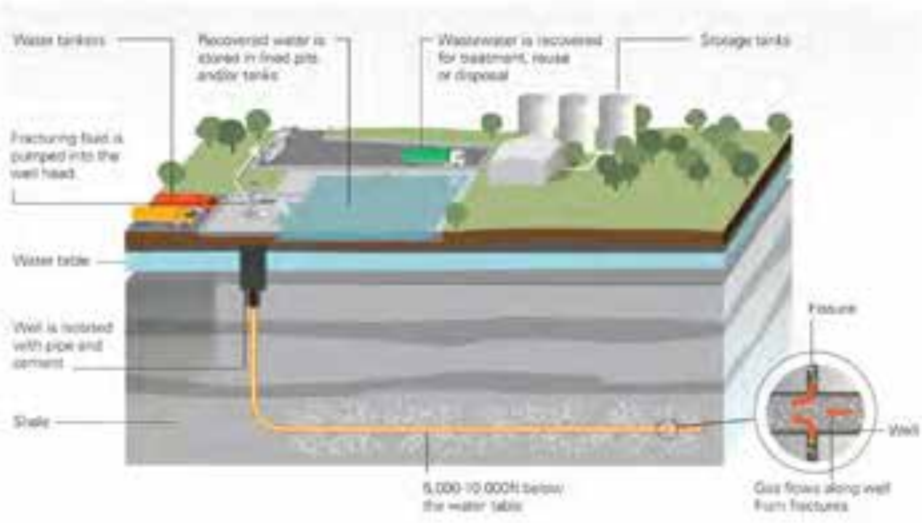
[c] The specific types of chemical additives used, and the proportions of each, depend on the type of rock formation that is being fractured. Additives function as friction reducers, biocides, oxygen (O_2) scavengers, stabilizers, and acids, all of which are necessary to optimize production. The composition of these fluids and the purposes of the additives are described in more detail in Chapter 4 – Water Use and Quality.

Exhibit 1-1. Schematic geology of natural gas resources



Source: Energy Information Administration (EIA 2023b)

Exhibit 1-2. Schematic geology of natural gas resources (3D)



Permission pending from BP (2017)

Commented [TC22]: I assume NETL has requested permission for all the figures, what is the timeline for getting these permissions in place?

Commented [ST23R22]: NETL: please create a graphic permission tracker with the received permissions contained/linked to archive with the project files. Thank you.

1.1.1 Liquefied Natural Gas

[illegible] LNG is natural gas that has been cooled to a liquid state (~~i.e., cooled to about~~approximately –260° Fahrenheit). The volume of natural gas in a liquid state is about 600 times smaller than ~~the volume of natural gas~~ in a gaseous state. Liquification of natural gas makes it possible to transport natural gas to places where pipelines currently do not exist or current pipeline infrastructure is unable to reach as well as for natural gas storage for end-use reliability ~~(e.g., abroad)~~. Liquefying natural gas is one way to allow markets that are far away from production regions to access natural gas. Once in liquid form, natural gas can be shipped to terminals around the world via ocean tankers and in some cases by LNG transport trailers (i.e., trucks). At these terminals, the LNG is returned to its gaseous state and transported by pipeline to distribution companies, industrial consumers, and power plants (DOE, 2021).

1.2 U.S. Natural Gas Resources

Annual U.S. production of dry natural gas was approximately ~~equal to~~ 35.81 trillion cubic feet (Tcf) in 2022 (an average of about 98.11 billion cubic feet [Bcf] per day). Production has mostly increased year over year since 2005 as hydraulic fracturing combined with horizontal drilling of shale, sandstone, carbonate, and other geologic formations has continued. About 70~~.4~~ percent of domestic dry natural gas production in 2021 was supplied by [illegible] of the United States's 34 natural gas-producing states. States with a larger percentage share of total U.S. dry natural gas production in 2021 include Texas (24.6 percent), Pennsylvania (21.8 percent), Louisiana (9.9 percent), West Virginia (7.4 percent), and Oklahoma (6.7%) (Exhibit 1-3) (EIA, 2023b).

Commented [TC24]: Are there years that it did not increase? I'd rather not use "mostly" unless necessary. Would prefer to say, "With the except of X years, production has increase year over year since 2005..."

Exhibit 1-3. U.S. natural gas production by state in 2021

eia Data source: U.S. Energy Information Administration, Natural Gas Annual, September 2022

Source: EIA (2023b)

Commented [HSAJ25]: Notes/Questions for [illegible]

1. State-Level production data is not yet available for 2022 from the EIA. Do you prefer we remove this figure?

Commented [ST26R25]: NETL: Keep figure BUT add to paragraph above the 2021 US dry gas production total put it in context to the 2022 value and support the 2021 figure. It is okay to state that 2022 state level data was not available at the time of report production in a footnote if you would like.

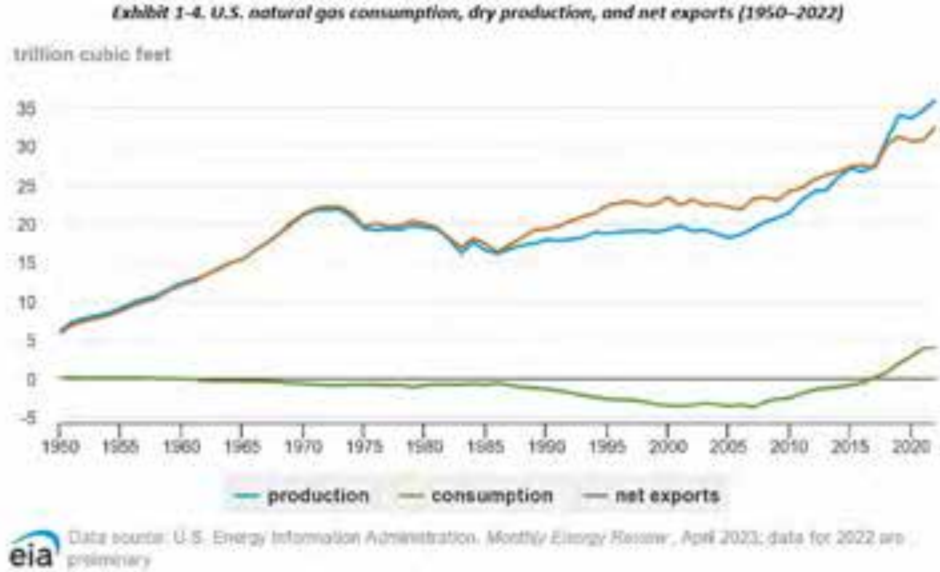
Commented [HSAJ27R25]: Add paragraph on 2021 dry production national volume to set up explanation.

In 2022, production from coalbeds accounted for about 2 percent of U.S. dry natural gas production, and supplemental gaseous fuels accounted for about 0.2 percent. Supplemental gaseous fuels include biogas (sometimes called renewable natural gas), synthetic natural gas, and other gases. Although most of the natural gas wells operated by the United States are located onshore, some wells are drilled offshore (i.e., into the ocean floor in waters off the coast of the United States). In 2022, offshore dry natural gas production was approximately equal to 0.80 Tcf, accounting for about 2.3 percent of total production. The majority—87.6 percent—of this production occurred in federally managed waters within the Gulf of Mexico (EIA, 2023c).

In addition to being a producer of natural gas, the United States is also a consumer and net exporter of natural gas. In 2022, the United States produced about 10.8 percent more natural gas than it consumed. While there was sufficient domestic production to meet our consumption requirements, the United States did import some natural gas, mostly from Canada. However, on a net basis, the United States was an exporter of natural gas. ~~; not enough, however, to no longer be considered a net exporter.~~ Exhibit 1-4 highlights recent (2022) and historical (1950–2021) U.S. natural gas production, consumption, and net exports (EIA, 2023c).

Commented [ST28]: NETL: we removed all discussion of projections from this document that followed Exhibit 1-4. Projections will be covered by the GCAM/NEMS work. Thanks.

Exhibit 1-4. U.S. natural gas consumption, dry production, and net exports (1950–2022)



Source: EIA (2023c)

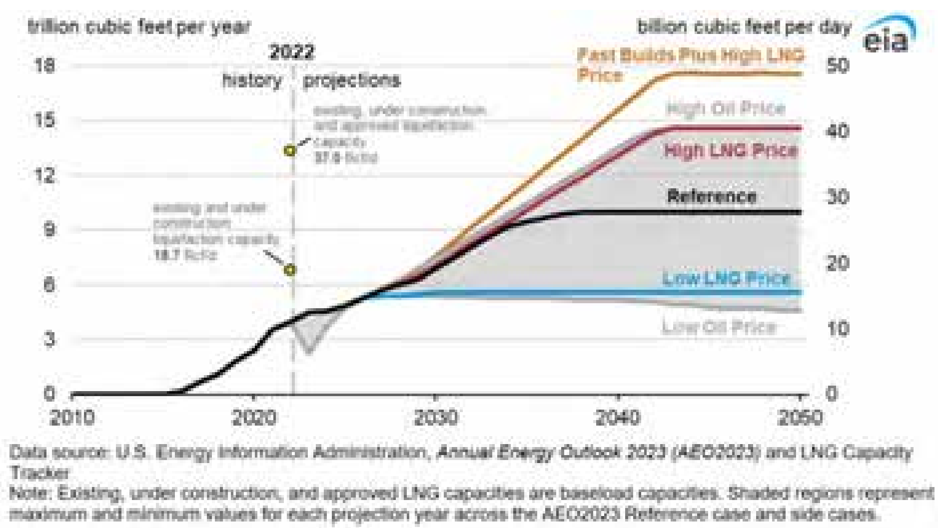
~~According to EIA's Annual Energy Outlook 2023 (AEO2023) reference scenario, domestic natural gas consumption is projected to decrease slightly but remain relatively constant out to 2050. Domestic natural gas production is projected to increase slightly and then also remain relatively constant out to 2050; see Exhibit 1-5 (EIA, 2023a).~~

~~Exhibit 1-5. Natural gas consumption and dry production projections through 2050~~

~~Source: EIA (2023a)~~

~~The AEO2023 reference scenario also projects that exports of natural gas, primarily LNG, will continue to increase between now and around 2035 (see Exhibit 1-6).~~

~~Exhibit 1-6. U.S. LNG export projections through 2050~~



~~Source: EIA (2023a)~~

1.3 U.S. Regulatory Framework and Federal Research and Development Programs

The following sub-sections provide a review of both federal and state regulatory responsibilities related to the production, transportation, use, and export of domestic natural gas resources.

1.3.1 Federal

Multiple federal agencies have authority over the production of unconventional natural gas resources. Three of these agencies—DOE, the Department of the Interior (DOI), and the Environmental Protection Agency (EPA)—play a critical role as they are charged with monitoring, assessing, and reporting on various environmental impacts Exhibit 1-5 describes the roles and responsibilities of these three agencies in more detail in addition to the way these agencies work together to inform policy-relevant science.

Commented [HSAJ29]: Let today (7/31) conversation lead the way on approach to addressing revisions. Plan should be to consolidate. For each chapter see if it makes sense to move content in the chapter to this section of the report.

Exhibit 1-5. Key U.S. agencies and their roles in natural gas development and production

Commented [HSAJ30]: Maybe add a Venn Diagram of interaction between federal and state if we can. It may or may not be possible.

Source: DOE

EPA is in charge of regulating underground injection and disposing of wastewater resources and other liquids covered under the Safe Drinking Water Act (SDWA). They are also charged with regulating the air emissions covered under the Clean Air Act .

Commented [EK31]: Please add CAA to the Acronyms List.

Federal agencies including EPA, DOI's Bureau of Land Management (BLM), the National Park Service (NPS), the Occupational Safety and Health Administration , and the U.S. Forest Service (USFS) are responsible for enforcing regulations for unconventional natural gas wells drilled on public lands. BLM is responsible for ensuring the environment of these lands remains protected and unaffected by natural gas production and other related activities.

Commented [EK32]: Please add OSHA to the Acronyms List.

USFS and BLM are both responsible for managing natural gas development on federally owned lands. Natural gas production and other related activities that will or do take place within the boundaries of our nation's national parks and other land managed by the ~~are the responsibility of~~ NPS, which establishes regulations to protect park resources and visitor values. Exhibit 1-6 provides some examples of federal statutes that apply to unconventional natural gas development.

Exhibit 1-6. Selected federal regulations that apply to unconventional oil and gas development

Statutes	Applicability
Clean Air Act	Places requirements on air emissions from sources of emissions at well sites; addresses compliance with existing and new air regulations, often delegated to local and state agencies. Generally, there is no distinction made between conventional and unconventional wells under the Clean Air Act.
Comprehensive Environmental Response, Compensation, and Liability Act	Only applies if hazardous substances besides crude oil or natural gas are released in quantities that require reporting. Natural gas releases do not require notification under the Comprehensive Environmental Response, Compensation, and Liability Act, but other hazardous substances may be released in reportable quantities during natural gas production.
Clean Water Act	Limits pollutants on produced water discharge under the National Pollutant Discharge Elimination System; stormwater runoff containing sediment that would cause a water-quality violation requires a permit under Clean Water Act decisions. Beneficial uses of surface waters are protected under Section 303.
Emergency Planning and Community Right-to-Know Act	Requires facilities storing hazardous chemicals above the threshold to report same and provide a Material Safety Data Sheet to officials and fire departments.
Endangered Species Act	Prohibits federal agencies from taking any action that is likely to jeopardize the continued existence of any endangered or threatened species (listed species) or result in the destruction or adverse modification of such species' designated critical habitat (Section 7); prohibits the taking of a listed species (Section 9); allows the Fish and Wildlife Service and National Marine Fisheries Service to issue a permit, accompanied by an approved habitat conservation plan, that allows for the incidental, non-purposeful "take" of a listed species under their jurisdictions (Section 10).
National Environmental Policy Act	Requires analysis of potential environmental impacts of proposed federal actions, such as approvals for exploration and production on federal lands.
Oil Pollution Act	Identifies spill prevention requirements, reporting obligations, and response planning (measures that will be implemented in the case of release of oil or other hazardous substances).
Resource Conservation and Recovery Act	Addresses non-hazardous solid wastes under Subtitle D. The Solid Waste Disposal Act exempts many wastes produced during the development of natural gas resources, including drilling fluids and produced water. EPA has determined that other federal and state regulations are more effective at protecting health and the environment.
Safe Drinking Water Act	Prevents the injection of liquid waste into underground drinking water sources through the Underground Injection Control (UIC) program. Fluids other than diesel fuel do not require a UIC permit. The UIC program gives requirements for siting, construction, operation, closure, and financial responsibility. Forty states control their own UIC programs.

1.3.1.1 Bureau of Land Management

BLM manages the U.S. government's onshore subsurface mineral estate, an area of about 700 million (MM) acres held jointly by BLM, USFS, and other federal agencies and surface owners.

Natural gas produced from the U.S. government's onshore subsurface mineral estate represents a significant portion of our nation's energy mix. In fiscal year 2022[d], sales of oil, gas, and natural gas liquids produced from the U.S. government's onshore subsurface mineral estate accounted for approximately 11 percent of all oil and 9 percent of all natural gas produced in the United States. About 23 MM acres had been leased to natural gas developers by the end of that year, and about 12.4 MM of those acres were producing natural gas in economic quantities (BLM, 2023). BLM published a rule regulating fracking on public lands on March 26, 2015—this rule was rescinded on December 28, 2017 (Fitterman, 2021).

1.3.1.2 *Environmental Protection Agency*

EPA's New Source Performance Standards (NSPS) under the CAA set the regulations for emissions sources from the oil and natural gas sector. Exhibit 1-7 illustrates the scope of NSPS established to-date and the way regulations have evolved in scope since 2012 (EPA, 2021).

Exhibit 1-7. Natural gas sources covered by EPA's proposed NSPS and Emissions Guidelines, by site

Location and Equipment or Process Covered	Required to or Would be Required to Reduce Emissions under EPA Rules (if finalized as proposed)	Rules that Apply			
		2012 NSPS for VOCs (OOOO)	2016 NSPS for Methane & VOCs (OOOOa)	2021 Proposed NSPS for Methane & VOCs (OOOOb)	2021 Proposed Emissions Guidelines for Methane (OOOOc)
Oil and Natural Gas Well Sites					
Completions of hydraulically fractured wells	✓	•	•	•	
Compressors at centralized tank batteries	✓			•	•
Fugitive emissions	✓		•	•	•
Liquids unloading	✓			•	
Pneumatic controllers	✓	•	•	•	•
Pneumatic pumps	✓		•	•	•
Storage vessels	✓	•	✓	•	•
Sweetening units	✓	✓	✓	•	•
Associated gas from oil wells	✓			•	•
Natural Gas Gathering and Boosting Compressor Stations					
Compressors	✓	•	•	•	•
Fugitive emissions	✓		•	•	•
Pneumatic controllers	✓	•	•	•	•
Pneumatic pumps	✓			•	•
Storage vessels	✓	•	✓	•	•
Sweetening units	✓	✓	✓	•	•
Natural Gas Processing Segment					
Compressors	✓	•	•	•	•
Fugitive emissions	✓	•		•	•
Pneumatic controllers	✓	•	•	•	•
Pneumatic pumps	✓		•	•	•
Storage vessels	✓	•	•	•	•
Sweetening units	✓	•	✓	•	•
Transmission and Storage Segment					
Compressors	✓		•	•	•
Fugitive emissions	✓		•	•	•
Pneumatic controllers	✓		•	•	•
Pneumatic pumps	✓			•	•
Storage vessels	✓	•	•	•	•

[1]Covered for SO_2 only; [2]Covered for VOCs only

Source: EPA

EPA's Greenhouse Gas Reporting Program (GHGRP) requires reporting of GHG emissions data and other relevant information ~~to be reported~~ by large sources of emissions, including fuel and industrial gas suppliers and CO_2 injection sites (EPA, 2023). The data reported is available to businesses, stakeholders, and other [illegible]s interested in tracking and comparing the GHG emissions of facilities, identifying opportunities to reduce emissions, minimizing wasted energy, and saving money. ~~States, cities, and communities can also use EPA's GHG data to identify high-~~

[d] October 1, 2021 through September 30, 2022

Commented [TC33]: BLM proposed rules to regulate methane releases in federal lands in 2021. Interior Department Takes Action to Reduce Methane Releases on Public and Tribal Lands | Bureau of Land Management (blm.gov)

Commented [ST34R33]: NETL: please add the 2021 rule to the discussion.

Commented [TC35]: I recommend revising this section to generally discuss EPA's role establishing regulations for air, GHG emissions, and water. The specifics on each could then be moved to the appropriate sections in the chapters.

Commented [ST36R35]: NETL: Note global guidance is to consolidate at a high level the regulatory discussion within Chapter 1. Please disregard the following part of the comment form Tom above " The specifics on each could then be moved to the appropriate sections in the chapters."

Commented [HSAJ37R35]: First part of Tom's comment should still be addressed.

~~emitting facilities in their areas, compare emissions between similar facilities, and develop common-sense climate policies for constituents.~~ The petroleum and natural gas industry is covered under Subpart W of EPA's GHGRP. Unconventional natural gas production is covered under the provisions for onshore production, natural gas processing, natural gas transmission, and LNG storage and import/export. Annual CO_2, CH_4 and nitrogen oxides (NOx) emissions must be reported separately for each of these segments.

EPA studied the relationship between hydraulic fracturing for oil and natural gas and drinking water resources (EPA, 2022a). The study includes a review of published literature, analysis of existing data, scenario evaluation and modeling, laboratory studies, and case studies. EPA released a progress report in December 2012, a final draft assessment report for peer review and comment in June 2015, and the final report in December 2016. The final EPA report concludes that hydraulic fracturing activities can impact drinking water resources under some circumstances and identifies factors that influence these impacts.

A core element of the SDWA UIC program is setting requirements for proper well siting, construction, and operation to minimize risks to underground sources of drinking water. The Energy Policy Act of 2005 excluded hydraulic fracturing (except when diesel fuels are used) for oil, natural gas, or geothermal production from regulation under the UIC program. This statutory language caused regulators and the regulated community alike to raise questions about the applicability of permitting practices. As a result, EPA developed revised UIC Class II permitting guidance specific to oil and natural gas hydraulic fracturing activities using diesel fuels (EPA, 2022a). Although developed specifically for hydraulic fracturing where diesel fuels are used, many of the guidance's recommended practices are consistent with best practices for hydraulic fracturing in general, including those found in state regulations and model guidelines for hydraulic fracturing developed by industry and stakeholders. Thus, states and tribes responsible for issuing permits and/or updating regulations for hydraulic fracturing will find the recommendations useful in improving the protection of underground sources of drinking water and public health wherever hydraulic fracturing occurs. The guidance outlines for EPA permit writers, where they are the permitting authority, (i) existing Class II requirements for diesel fuels used for hydraulic fracturing wells, and (ii) technical recommendations for permitting those wells consistently with these requirements (EPA, 2022a).

EPA completed a stakeholder engagement effort in 2020 that sought input on how the agency, states, tribes, and stakeholders regulate and manage wastewater from the oil and gas industry. EPA released a draft report in May 2019 that described what it heard during its engagement for this study (EPA, 2022a). EPA accepted public input on the draft report and, after considering this input, published a final report. In many regions of the United States, underground injection is the most common method of managing fluids or other substances from shale gas extraction operations. Management of flowback and produced water via underground injection is regulated under the SDWA UIC program. The Clean Water Act effluent guidelines program sets national standards for industrial wastewater discharge to surface waters and municipal sewage treatment plants based on the performance of treatment and control technologies. Effluent guidelines for onshore oil and natural gas extraction facilities prohibit the discharge of pollutants into surface waters, some permit exception may allow for discharge under unique conditions. ~~, except for wastewater that is of good enough quality for use in~~

Commented [LBD38]: Please check timing/dates – 2020 engagement was reported on in 2019?

Commented [LBD39]: Citation?

Commented [EK40]: Please add CWA to the Acronym List.

~~agricultural and wildlife propagation for those onshore facilities.~~ On June 28, 2016, EPA promulgated pretreatment standards for the Oil and Gas Extraction Category (40 Code of Federal Regulations Part 435). These regulations prohibit discharge of wastewater pollutants from onshore unconventional oil and natural gas extraction facilities to publicly owned treatment works.*

On December 6, 2022, EPA issued a supplemental proposal to update, strengthen, and expand standards intended to significantly reduce emissions of GHG and other harmful air pollutants from the Crude Oil and Natural Gas source category (EPA, 2022b). First, EPA proposed standards for certain sources that were not previously addressed. Second, EPA proposed revisions that strengthen standards for sources of leaks, provide greater flexibility to use innovative advanced detection methods, and establish a super-emitter response program. Third, EPA proposed to modify and refine certain elements of the proposed standards in response to information submitted in public comments. Finally, EPA proposed details of the timelines and other implementation requirements that apply to states to limit CH_4 pollution from existing designated facilities in the source category under the C[illegible] (EPA, 2022b).

1.3.1.3 Department of Energy

The N[illegible] requires DOE to make public interest determinations on applications to export LNG to countries where the United States does not have existing free_-trade agreements requiring national treatment for trade in natural gas. The Office of Fossil Energy and Carbon Management's (FECM) natural gas import–export regulatory program is implemented by the Division of Regulation in the Office of Regulation, Analysis, and Engagement. Typically, the Federal Energy Regulatory Commission (FERC) has direct regulatory responsibility over the siting, construction, and operation of onshore LNG export facilities in the United States. In these cases, FERC leads the environmental impact assessments of proposed projects consistent with the National Environmental Policy Act, and DOE is typically a cooperating agency as part of these reviews (DOE, 2023a). Similarly, for offshore LNG export facilities, the Department of Transportation's Maritime Administration is responsible for environmental reviews, in coordination with the Coast Guard, guided by requirements in the Deepwater Port Act. Again, DOE is typically a cooperating agency in these reviews. In some limited circumstances, DOE is the lead agency for NEPA reviews related to proposed LNG exports.

FECM's Point Source Carbon Capture Division's research, development, demonstration, and deployment portfolio facilitates the development of technologies and infrastructure that improve performance, reduce costs, and scale the deployment of technologies to decarbonize the industrial and power sectors and remove CO_2 from the atmosphere. Within the natural gas supply chain, these efforts include research and commercial-scale demonstration of

Commented [LBD41]: Is there anything that can be said at the end of the paragraph on current status? Or timeline expected for final rule?

Commented [HSAJ42R41]: If it is significant it may be worth noting what is in process. But we don't want to mention what will happen. Take an agnostic approach and mention it is in progress.

Commented [EK43]: Please add NEPA to the Acronym List.

Commented [EK44]: Please add both DOT and MARAD to the Acronym List.

Commented [EK45]: Please add USCG to the Acronym List.

* "Publicly owned treatment works" is a term used in the United States to designate a sewage treatment plant owned, and usually operated, by a government agency. In the United States, publicly owned treatment works are typically owned by local government agencies and are usually designed to treat domestic sewage and not industrial wastewater.

technologies that advance carbon capture and storage on natural gas-fired power plants and industrial natural gas combustion streams (DOE, 2023a).

FECM is working to support efforts to decarbonize LNG terminals through ~~deployment~~ exploration of technical and economic feasibility of carbon capture on gas separation and combustion streams and the use of electric motor drives supplied by net-zero emissions electricity. Decarbonizing LNG terminals is a key part of the effort to reduce life cycle emissions associated with the export of natural gas to global allies. ~~Additionally, DOE has regulatory responsibilities related to LNG. Companies that want to export LNG must get authorization to do so from FECM.~~

FECM's Methane Mitigation Technologies Division aims to eliminate non-trivial fugitive and vented CH_4 emissions from the natural gas supply chain to reduce the climate impacts from the production and use of natural gas. The division is focused on developing accurate, cost effective, and efficient technology solutions and best practices to identify, measure, monitor, and minimize CH_4 emissions from these sources. DOE has funded several technology investigations through NETL that deal with produced water management and life cycle assessments of the natural gas value chain (DOE, 2023b).

DOE's shale gas research program brings together federal and state agencies, industry, academia, non-governmental organizations, and national laboratories to develop technologies that enable safe, environmentally sustainable oil and gas production. DOE's shale gas research program is tasked with calculating the risks of oil and gas exploration and production undertakings. ~~DOE has funded several technology investigations through NETL that deal with produced water management and life cycle assessments of the natural gas value chain (DOE, 2023b).~~

On April 21, 2023, a Request for Information was issued by FECM to obtain input to inform DOE's research and development activities within the Office of Research and Development's Methane Mitigation Technologies Division and the Office of Carbon Management Technologies' Point Source Carbon Capture Division. In addition, such data and information could help inform the Office of Regulation, Analysis, and Engagement's capabilities to assess natural gas import and/or export applications ~~under the Natural Gas Act of 1938, as amended~~. Through the R~~equest for Information~~, DOE ~~is~~ requested~~ing~~ information on strategies and technologies that natural gas and LNG companies are deploying, or could deploy, to reduce GHG emissions and other air pollutants associated with natural gas delivered to liquefaction facilities, housed at liquefaction facilities, and being loaded, transported, and delivered to regasification facilities (DOE, 2023a).

1.3.2 States

States have the power to implement their own requirements and regulations for unconventional natural gas drilling that are equivalent to or more stringent than established federal practices. ~~with federal oversight.~~ All states that produce natural gas have at least one agency charged with issuing new permits for production wells. While state requirements for permits can differ, any requirements set forth by federal regulations must be met ~~in order~~ for a state-level permit to be issued.

Commented [ST46]: We issued an RFI, but do we have funded work on these paths today?

Commented [ST47R46]: NETL: we softened this language as we have not funded CCS or electric motor conversion to support the verb "deployment".

Commented [HSAJ48R46]: No answer on top question required. Double check changes don't impact author's point/message.

Commented [ST49]: This sentence is broader than Shale Gas Research and better aligns to the Methane Mitigation paragraph above for the LCA work. Produced water is in a different program line as well.

Commented [HSAJ50R49]: Moved sentence so just double check it is still within context.

Commented [EK51]: Please add NGOs to the Acronym List.

Commented [ST52]: This sentence is broader than Shale Gas Research and better aligns to the Methane Mitigation paragraph above for the LCA work. Produced water is in a different program line as well.

Commented [ST53R52]: NETL: We moved the sentence. Please confirm you are okay with the move.

Commented [EK54]: Please add RFI to the Acronym List.

Commented [EK55]: Please add R&D to the Acronym List.

NETL evaluated the state regulatory programs for oil and natural gas production for their applicability and adequacy of protecting water resources (NETL, 2014). NETL also reviewed regulations for permitting, well construction, hydraulic fracturing, temporary abandonment, well plugging, tanks, pits, and waste handling and spills. This evaluation revealed several key messages (NETL, 2014):

1. State oil and gas regulations are adequately designed to directly protect water resources through the application of specific programmatic elements such as permitting, well construction, well plugging, and temporary abandonment requirements.
2. Experience suggests that state oil and gas regulations related to well construction are designed to be protective of groundwater resources relative to the potential effects of hydraulic fracturing. However, development and dissemination of best management practices related to hydraulic fracturing would assist states and operators in ensuring continued safety of the practice, especially as it relates to hydraulic fracturing of zones near groundwater, as determined by the regulatory authority.
3. Many states divide jurisdiction over certain elements of oil and gas regulation between the oil and gas agency and other state water protection agencies. This is particularly evident in the areas of waste handling and spill management.
4. The implementation and advancement of electronic data management systems has enhanced regulatory capacity and focus. However, the inclusion of more environmental data is needed, as well as further work in the areas of paper-to-digital data conversion.

In 2014, EPA compiled a summary of state regulatory programs for oil and natural gas exploration, development, and production (EDP) solid waste management. This review was conducted by EPA personnel in the Office of Resource Conservation and Recovery within the Office of Solid Waste and Emergency Response ~~and. The review~~ included relevant regulations for Ohio, Oklahoma, Pennsylvania, Texas, and West Virginia, which are presented below that help to drive sustainable practices within these leading oil and gas producing states (EPA, 2014).

1.3.2.1 Ohio

Regulations concerning technical requirements for waste pits are found in Chapter 1501 of the Ohio Administrative Code (OAC) and Rule 1509 of the Ohio Revised Code (ORC), which contains the statutory authority for the regulations promulgated in the OAC as regulated by the Division of Mineral Resources Management in the Department of Natural Resources. The complete set of applicable regulations can be found in Appendix OH-3. Regulations relevant to this addendum include the following:

- OAC 1501:9-1-02 details the requirements for the permitting of wells, including the plan for disposal of water and other waste substances resulting from oil and gas exploration and production activities.
- OAC 1501:9-3-08 details temporary storage of saltwater and other related waste, including design criteria for storage pits.

Commented [TC56]: States also have authority to regulate air emissions from facilities. I would recommend deleting the detailed summary of the adequacy of protecting water resources and include a high-level discussion of state authorities to regulate oil and gas production and associated impacts.

Commented [EK57]: Should we add language that indicates these state O&G regulatory programs, originally summarized in 2014, remain essentially unchanged and continue to be highly effective? Do we have current or recent information that confirms that state of play nearly a decade later? Just concerned potential gas development opponents will consider state regulatory regimes - if they are essentially unchanged in the past decade might be deemed potentially lacking given the U.S. is now a net natural gas exporter?

Commented [ST58R57]: NETL: we are strongly concerned that a 2014 summary is no longer accurate. Can you confirm your summary is current? If yes, please explain. If not, then we need to pull this back to a higher level discussion of the role that states have in regulating solid waste from NG operations. This comment is in line with HQ's broader comments on accuracy of regulatory sections with respect to representing current landscape.

Commented [HSAJ59R57]: Latest consolidated analysis of states - but we should likely take this out because it is dated.

Commented [HSAJ60]: States can be consolidated into one general section but could reference "following x states are leading in regulatory space." Want to avoid calling out specific state w/o providing context for why specific states are highlighted. Might be better to break it out by impact - water, seismicity, etc.

Commented [HSAJ61]: Could summarize what is in the bullets at a high-level but **also provide link to "latest" regulations.**

- OAC 1501:9-9-05 specifies tank location restrictions, including setbacks from public roads, inhabited structures, wells, heaters, and other equipment.
- OAC 1501:9-9-03 requires pits of sufficient size and shape to be constructed adjacent to each drilling well to contain all the drilling muds, cuttings, saltwater, and oil.
- OAC 1501:9-9-05 specifies that where a hazard exists, any production equipment at the wellhead and related storage tanks must be protected by an earthen dike or earthen pit with a capacity to contain any substances produced by operation of the related oil or gas well.
- ORC 1509.072 discusses the obligation to restore the land surfaces after drilling operations have ceased, including removing all equipment, revegetating the affected area, preventing sedimentation and erosion, and authorizing the chief retains in the closure of a well.
- ORC 1509.22 discusses the prohibition of water contamination and covers storage and disposal of brine. This section also discusses the storage of waste fluids and the management allowances for these fluids.

1.3.2.2 Oklahoma

Regulations concerning technical requirements for oil field waste pits in Oklahoma are found primarily in Oklahoma Administrative Code, Title 165, Chapter 10, Subchapters 3 and 7 as regulated by the Oklahoma Corporation Commission Division of Oil and Gas. Regulations relevant to this addendum include the following:

- 165: 10-7-16 details minimum technical design standards for waste pits.
- 165:10-7-5 details operating requirements for pits, specifically operating standards in the event of a discharge, including reporting details and requirements along with record-keeping requirements.
- 165:10-7-16.(d) details operating requirements for oil and gas exploration and production activity pits.
- 165:10-3-16.(e) details closure requirements for pits.
- 165:10-3-17 details further closure requirements, primarily the return of the surface conditions at the site of the pit to their original state, free of trash, debris, and equipment, within 90 days of the completion of well activities.

1.3.2.3 Pennsylvania

Regulations concerning technical requirements for oil field waste pits in Pennsylvania are found primarily in Pennsylvania Code, Title 25 (Environmental Protection), Part 1 (Department of Environmental Protection), Subpart C (Protection of Natural Resources), Article I (Land Resources), Chapter 78 (Oil and Gas Wells) and Chapter 91 (General Provisions). Additional language can be found in Pennsylvania (PA) Act 13 of 2012. Regulations relevant to this addendum include the following:

- PA Act 13 of 2012 §3215 prevents wells from being sited in any floodplain if the well is to employ a pit or impoundment or a tank managing solid wastes from oil and gas exploration and production.
- PA Act 13 of 2012 §3216 requires that a well site be restored following cessation of drilling operations. This includes restoration of the earthwork or soil disturbed, removal of all drilling supplies and equipment within nine months after completion of the drilling well, and compliance with all applicable requirements of the Clean Streams Law. The restoration period is subject to an extension if certain conditions are met.
- PA Act 13 of 2012 §78.56 details requirements for pits and tanks that are used to manage waste temporarily. Some requirements include a minimum of 2 ft of freeboard for pits or impoundments, structural soundness of pits and tanks, minimum liner requirements, and waste separations and prohibitions.
- PA Act 13 of 2012 §78.57 details requirements for management of production fluids, including collection of brine and other fluids from the well operations, requirements for pits, removal and disposal of fluids, and restoration of the waste management units or facilities following the closure or cessation of operations.
- PA Act 13 of 2012 §78.61 details the requirements for disposal of drill cuttings, including criteria to be met to allow for disposal in a pit, criteria to be met to allow for disposal by land application, other methods of disposal of drill cuttings, and compliance requirements for disposal.
- PA Act 13 of 2012 §78.64 details secondary containment criteria to be met for tanks used on drill sites, including required capacity and inspection requirements.
- PA Act 13 of 2012 §78.65 details site restoration requirements following the cessation of operations at a well site.

1.3.2.4 Texas

Regulations concerning technical requirements for solid waste management of oil and gas exploration, production, and development in Texas are found primarily in the Texas Administrative Code, Title 16, Part 1, Chapters 1–20. The Railroad Commission of Texas (RRC) is the primary authority in Texas regarding the regulation of oil and natural gas. Regulations relevant to this addendum include the following:

- Rule §3.3 details that all tanks must be clearly identified by signage at all times.
- Rule §3.5 details that a permit is required, issued by the RRC, in order to drill, deepen, plug back, or reenter any oil, gas, or geothermal resource well. The rule does not include any required specifications for waste management in the permit.
- Rule §3.8 defines the various types and functions of pits that are to be found in the regulations. Additionally, the rule defines oil and gas waste. The rule sets forth~~defines~~ what types of pits are prohibited, including for the storage of oil products, the requirement to obtain a permit for constructing and operating a pit, authorized disposal

methods, liner requirements, minimum freeboard provisions, steps to ensure prevention of run-on from stormwater, and procedures for the draining of pits and inspection of pit liners. In addition, tThe Rule details instances in which a pit may be used without a permit, including as a reserve pit, completion pit, or basic sediment pit. The Rule also notes that the pit operator must keep records detailing that the pit liner requirements are met.

- Rule §3.15 details the requirements for the removal of all surface equipment from inactive wells, including the removal of all tanks or tank batteries.
- Rule §3.22 details the requirements of screening or netting of pits to protect wildlife, specifically birds.
- Rule §3.57 details the requirements for reclaiming tank bottoms and disposal of other EDP wastes. This includes the requirement for a permit, the use of a reclamation plant, and other miscellaneous requirements.
- Rule §3.78 details financial assurances and fees required ~~in order~~ to commence drilling activities. These financial assurances include bonding requirements for varying operations and number of wells.
- Rule §4.620 prohibits the disposal of naturally occurring radioactive material (NORM) waste by burying it or applying it with the land surface without obtaining a permit. The section details that the disposal of NORM waste is subject to Rule §3.8.

1.3.2.5 West Virginia

The following are oil and natural gas solid waste regulations for the state of West Virginia (WV):

- WV Code Chapter 22 Art. 6 Section 7, Chapter 22 Art. 11 Section 1–27, and Chapter 22 Art. 6 details permitting requirements and authority.
- WV Code Chapter 22 Article 6 Section 7 details waste pit authority of the general permit.
- WV Code Chapter 22 Series 6A contains the Horizontal Well Control Act.
- WV Code Title 35 Series 8 details horizontal well permits regarding the requirements and handling of waste cuttings.

Additionally, documentation that dictates surface and groundwater pollution prevention requirements for WV include the following:

- General Water Pollution Control Permit
- Erosion and Sediment Control Field Manual
- 35-8 Rules Horizontal Well Development
- 35-1 Water Pollution Control Rule

Below is a summary of some relevant sections of the WV code regarding oil and natural gas solid waste regulations relevant to this Addendum:

Commented [EK62]: NETL Team - please edit this awkward phrasing. It seems to suggest NORM may be 'applied' with the land surface. Just not sure what the writer here means precisely.

Commented [ST63]: No air regs in WV?

Commented [HSAJ64R63]: Do they just cover VOCs or Methane & Co2?

- §35-1-7 details requirements for dikes, berms, and retaining walls at oil and gas operations, requirements for secondary containment of tanks or tank systems, and other associated mechanical operational requirements.
- §35-4-16 details design and operation criteria for pits and impoundments.
- §35-4-21 describes design and construction requirements for pits and impoundments with a capacity greater than 5,000 barrels, including inspections.
- §35-2-3 requires that a permit be obtained by the Division of Environmental Protection, Office of Oil and Gas prior to the commencement of ~~any~~ solid waste management efforts ~~facilities~~ at the ~~site of~~ oil and gas exploration and production site.
- §35-4-10 details financial assurance requirements for oil and gas exploration and production activities, including the demonstration of financial responsibility of individual and grouped wells, coincidence with permit application for financial assurance, and the varying forms of financial assurance allowable.
- §35-8-5 details requirements for permits, notice, and review of horizontal wells, including siting restrictions, financial assurance for horizontal wells, and permitting requirements.

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Zendehboudi, S. and Bahadori, A. (2017). Chapter One - Shale Gas: Introduction, Basics, and Definitions, Shale Oil and Gas Handbook, Gulf Professional Publishing, Pages 1-26, ISBN 9780128021002

2 Greenhouse Gas Emissions and Climate Change

CH_4 and CO_2 emissions from the LNG life cycle ~~and natural gas end uses~~ vary widely across different regions and supply chains. This section presents a review of contemporary (2014 and after) life cycle analysis (LCA) as it pertains to LNG and natural gas GHG emissions.

2.1 Introduction

To account for all sources of GHG emissions in the natural gas supply chain, and to evaluate their relative contributions and mitigation opportunities, a systems-level perspective is both necessary and preferred. LCA is one type of systems approach available to account for the different sources of GHG emissions in the natural gas supply chain. LCA specifically considers the material and energy flows of an entire system, ~~-~~"from cradle to grave~~.~~," ~~W~~where ~~the~~ "cradle" refers to the extraction of resources from the earth, and ~~the~~ "grave" refers to the final use and disposition of all products.

Depending on the type of LCA conducted, different system boundaries can be put in place to more accurately estimate the GHG emissions associated with natural gas. Generally, GHG emissions occur from the beginning of the natural gas supply chain (during exploration) through the end (during utilization). In some cases, an LCA may not consider every step of the natural gas supply chain within its analysis framework. This can happen for a variety of reasons, including lack of emission data for a particular step or set of steps, or simply to focus specifically on the emissions associated with one particular ~~part~~ step. Exhibit 2-1 provides an illustration of the natural gas supply chain with examples of key emissions sources (Balcombe et al, 2016).

Exhibit 2-1. Natural gas supply chain with examples of key emission sources

Permission pending from Balcombe et al. (2016)

Commented [TS65]: This diagram is missing a few steps.

Gathering and Boosting

Piped Transmission and Storage between "Processing" and "Liquefaction".

Is there a more accurate diagram that better aligns with the NETL or EPA GHGRP or GHGI categories and emission sources?

Commented [HSAJ66R65]: Create custom NETL graphic.

There are two primary approaches used to conduct natural gas LCA: 1) top-down and 2) bottom~~s~~-up (Rutherford et al., 2021; Alvarez et al., 2018; Balcombe et al., 2016). A top-down approach ~~1~~a) measures the atmospheric concentrations of CH_4 as reported by fixed ground monitors, mobile ground monitors, aircraft, and/or satellite monitoring platforms; ~~2~~b) aggregates the results to estimate total CH_4 emissions; and ~~3~~c) allocates a portion of these total emissions to each of the different supply chain activities. A bottom~~s~~-up approach measures ~~CH_4~~ GHG emissions directly from each source of emissions, then aggregates and extrapolates these measurements to estimate emissions for an entire region or process. Both approaches have ~~their~~ advantages and disadvantages.

For example, several studies (Rutherford et al., 2021; Alvarez et al., 2018; Balcombe et al., 2016) have noted that top-down approaches may lead to a general upward bias in emissions reporting while bottoms-up approaches may lead to a general downward bias in emissions reporting. There are several factors that may lead to these biases, which can be generally explained as follows:

- Top-down approaches sometimes fail to distinguish between different sectors. For example, aircraft that are used to collect emissions data for a particular area may struggle to distinguish between the CH_4 emissions coming from a natural gas processing facility in the area from those coming from a near-by dairy farm. This can lead to incorrect contributions of total CH_4 emissions to specific natural gas activities.
- Bottom~~s~~-up measurements sometimes fail to capture "super emitters"—a small number of facilities (or types of equipment) ~~who~~ that emit disproportionately large quantities of emissions. Because bottom~~s~~-up approaches measure emissions from individual sources and because super emitters, by definition, represent only a small proportion of the total number of facilities (or equipment) represented within the natural gas supply chain, it can be challenging to accurately capture the contributions of ~~a~~ super emitter activity to total emissions.

Alvarez et al. (2018) also notes that in many bottom~~s~~-up approaches to modeling, operator cooperation is required to obtain site access for accurate emissions measurements. Operators with lower-emitting sites are plausibly more likely to cooperate with ~~the conduct of~~ such studies and workers are plausibly more likely to be careful to avoid errors or fix problems when measurement teams are on site or about to arrive, which could lead to a downward bias in estimates of potential emissions (Rutherford et al., 2021; Alvarez et al., 2018; Balcombe et al., 2016).

Another key difference in LCA methodology or assumptions that can lead to differences in LCA outputs (i.e., estimates of emissions) is tied to the choice of which climate-forcing impacts of CH_4 are is used (Balcombe et al., 2016). CH_4 emissions have a large short-term and climate-forcing impact[f] compared to CO_2. The instantaneous forcing impact of CH_4 is around 120 times that of CO_2 ~~on a~~ for an equivalent amount of mass ~~basis~~. CH_4, however, only has an average

[f] Climate or radiative forcing, a measure, is defined by the Intergovernmental Panel on Climate Change (IPCC) as the influence a given climatic factor has on the amount of downward-directed radiant energy impinging upon Earth's surface.

Commented [LBD67]: GHG emissions? Not only CH4, correct? In this section generally, sometimes reference is made to CH4 monitoring/detection - suggest some explanation of when only CH4 is measured and when all GHGs are considered.

Commented [HSAJ68R67]: Make distinction between just CH4 and GHG more clear.

Commented [TS69]: This needs to be balanced with the understanding that in the 12 year the radiative forcing is changing. I can not find a reference to support the 120 times? Is this in watts/meter perspective?

Recommend we stay with IPCC 100 yr and 20 year perspective of difference in radiative forcing.

The temporal period of how long the pollutant stays in the atmosphere is critical to understanding its relative radiative forcing when compared to other GHGs, CO2. Remove or provide the complete story.

Commented [HSAJ70R69]: Take this out.

lifespan of 12 years in the atmosphere, after which it oxidizes into CO_2. CO_2 emissions remain in the atmosphere for much longer—25 percent of CO_2 emissions ~~still exists~~remain in the ~~atmospheres~~atmosphere ~~after~~ 1,000 years after emission (Balcombe et al., 2016). Consequently, while the climate-forcing impact of CH_4 emissions changes significantly over time, the impact of CO_2 emissions remains ~~much more~~ constant for a longer time.

Commented [TS71]: CO2 also declines over time, not constant. The temporal period is just longer. You confirm my point in the previous sentence.

This paragraph is misleading because it is not telling the complete story. A radiative forcing decay graphic showing a single pulse of emissions at time = zero is needed to tell the complete story.

Alternatively, this paragraph. I would keep the first two sentences and use them as the start of the next paragraph on GWP.

Typically, studies use global warming potential (GWP) to compare the climate impact of emissions of different GHGs such as CH_4 with CO_2. The GWP is defined as a measure of how much energy the emissions of 1 ton of a gas will absorb over a given period, relative to the emissions of 1 ton of CO_2 (Balcombe et al., 2016). The IPCC progressively raised the GWP for CH_4 to 28 over a 100-year period and 84 over a 20-year period in their Fifth Assessment Report (AR5) published in 2014 (Stern, 2022). IPCC's Sixth Assessment Report (published in 2021) raised the GWP of CH_4 to 29.8 over a 100-year horizon but reduced the 20-year horizon factor to 82 (Stern, 2022). Adding climate feedback mechanisms and oxidation, these figures were increased to 36 and 87.15, respectively in the IPCC's Sixth Assessment Report.

To illustrate, if the GWP of CH_4 for a time horizon of 100 years is 36, this means that a pulse emission of CH_4 absorbs 36 times more energy than CO_2 over 100 years, on average. Note that the GWP of CH_4 for a time horizon of 100 years does not give any information on the climate forcing of CH_4 at the end of the 100 years; it gives only the average impact across the 100 years. ~~Additionally, the use of a single value to compare GHGs does not consider the changing impacts over time.~~ It is important to consider ~~the~~ which GWP is used when analyzing the outputs of an LCA, particularly when comparing the outputs of two or more LCAs (Balcombe et al., 2016).

2.2 Federally-Funded LCA

NETL has used LCA to calculate the environmental impacts of natural gas production and use for the generation of electric power for nearly a decade (NETL, 2023). Their work has been documented in a series of reports produced between 2010 and 2019.[g] Together, these reports provide in-depth assessments of the potential GHG emissions resulting from unconventional natural gas production in the United States. The GHG emissions results recorded in the NETL 2019 report considers five stages of the natural gas supply chain, which are visualized in Exhibit 2-2 (NETL, 2019):

Commented [TS72]: Need to mention the LNG work at the beginning and discuss that the LNG report builds upon the NELT upstream natural gas report by adding liquefaction, ocean transport, regasification, distribution and end use of the gas in a large scale power plant.

This will help create synergies to the Exhibit 2-1 description of the natural gas and LNG system boundary.

For Exhibit 2-1, you may want to create your own graphic.

1. **Production:** Sources of emissions include the gas vented from pneumatically controlled devices and fugitive emissions from flanges, connectors, open-ended lines, and valves. When vapor recovery units are feasible, vented gas is captured and flared; otherwise, vented gas is released to the atmosphere. Production operations also include the combustion of natural gas and diesel in compressors and other equipment.
2. **Gathering and Boosting (G&B):** Natural gas G&B networks receive natural gas from multiple wells and transport it to multiple facilities. G&B sites include acid gas removal, dehydration, compressors operations, pneumatic devices, and pumps.

[g] The GHG results in the NETL (2019) report supersede the GHG results in the previous NETL reports.

3. **Processing:** A natural gas processing facility removes impurities from natural gas, which improves its heating value and prepares it for pipeline transmission. Natural gas processing facilities include acid gas removal, dehydration, hydrocarbon liquids removal, and compression operations.

4. **Transmission Stations, Storage Facilities, and Transmission Pipelines:** A natural gas transmission system is a network of large pipelines that transport natural gas from processing facilities to the city gate (the point at which natural gas can be consumed by large-scale consumers or transferred to local distribution companies). Transmission stations are located along natural gas transmission pipelines and use compressors to boost the pressure of the natural gas.

5. **Distribution:** Natural gas distribution networks transport natural gas from the city gate to commercial, residential, and some industrial consumers. This analysis uses the distribution portion of the supply chain only for the upstream functional unit; distribution is not necessary for the functional unit of electricity in which natural gas power plants receive natural gas directly from transmission pipelines.

Exhibit 2-2. Supply chain stages that compose the overall LCA boundary

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Commented [HSAJ74R73]: Could give its own page to sharpen

The flexible, consistent framework of NETL's LCA model allows different natural gas sources to be compared on a common basis (per megajoule [MJ] of delivered natural gas). In the NETL (2019) report, five types of natural gas are considered:

1. **Conventional natural gas** is natural gas extracted via vertical wells in high permeability formations that do not require stimulation technologies for primary production.

2. **CBM** is extracted from coal seams and requires the removal of naturally occurring water from the seam before natural gas wells are productive.

3. **Shale gas** is extracted from low permeability formations and requires hydraulic fracturing and horizontal drilling.

4. **Tight gas** is extracted from non-shale, low permeability formations and requires hydraulic fracturing and directional drilling.

5. **Associated gas** is found with petroleum (either dissolved in oil or in a gas cap in a petroleum formation) and is produced by oil wells.

EPA estimates oil and natural gas CH_4 emissions in the annual Greenhouse Gas Inventory (GHGI) it produces. The GHGI uses a ~~bottoms~~-up approach to estimate national CH_4 emissions.

In its 2019 LCA analysis of the natural gas supply chain, NETL used the GWP reported in the IPCC AR5. Other key input data was sourced from EPA's GHGI, Drilling Info (DI Desktop), and EIA. Results from the 2019 NETL LCA analysis performed suggested the following:

Commented [TS75]: Add citation

Commented [TS76]: Add GHGRP (this is the primary data source, not GHGI)

- The life cycle GHG emissions associated with the U.S. natural gas supply chain were 19.9 grams (g) of carbon dioxide equivalents (CO_2e) per MJ of natural gas delivered (with a 95% mean confidence interval of 13.1–28.7 g CO_2e per MJ).
- The top contributors to CO_2 and CH_4 emissions were combustion exhaust and other venting from compressor systems. Compressor systems are prevalent in most stages of the natural gas supply chain and as such were key contributors to the total life cycle emissions estimated.
- Emission rates ~~were~~ are highly variable across the entire supply chain. According to the study (NETL, 2019), the national average CH_4 emissions rate was 1.24 percent, with a 95 percent mean confidence interval ranging 0.84–1.76 percent.

Exhibit 2-3 shows the upstream GHG emissions from the different parts of the natural gas supply chain. he blue bars represent CO_2 emissions, the green bars represent CH_4 emissions, and the orange bars represent nitrous oxide (N_2O) emissions. The vertical black lines in Exhibit 2-3 and Exhibit 2-4 represent the error bars in this analysis, and the shaded grey area represents the 95 percent mean confidence interval.

Commented [LBD77]: Suggest citing somehow that Exhibits 2-3 and 2-4 are from the referenced NETL 2019 report.

Exhibit 2-3. Life cycle CH_4 emissions from the U.S. natural gas supply chain

Commented [LBD78]: Figure would benefit from a legend or explanation of the different elements.

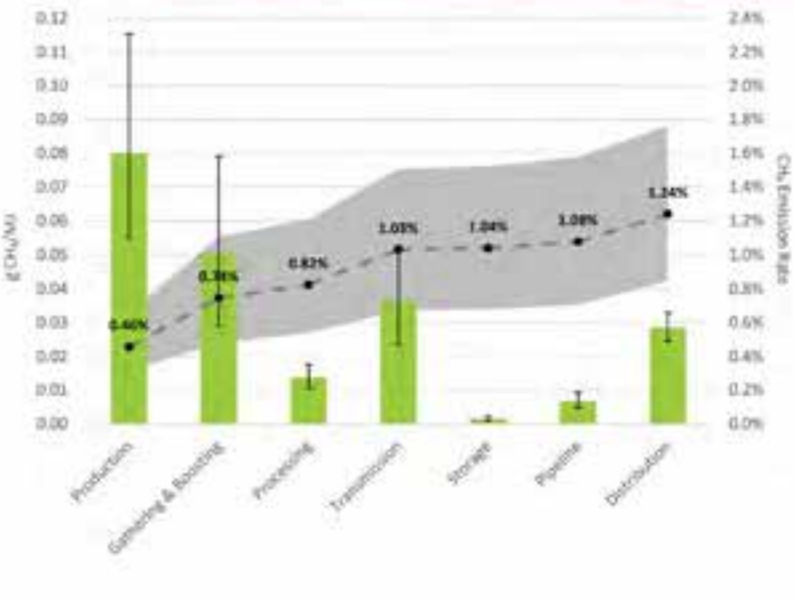
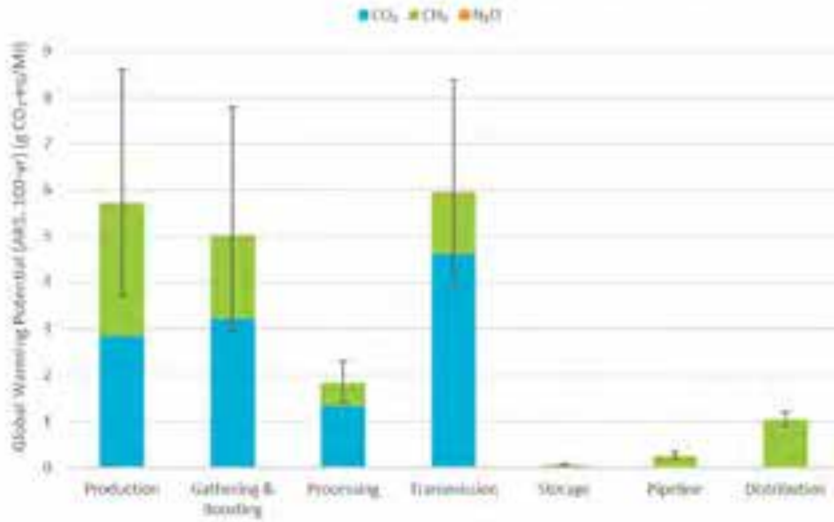


Exhibit 2-4. Life cycle GHG emissions for the U.S. natural gas supply chain



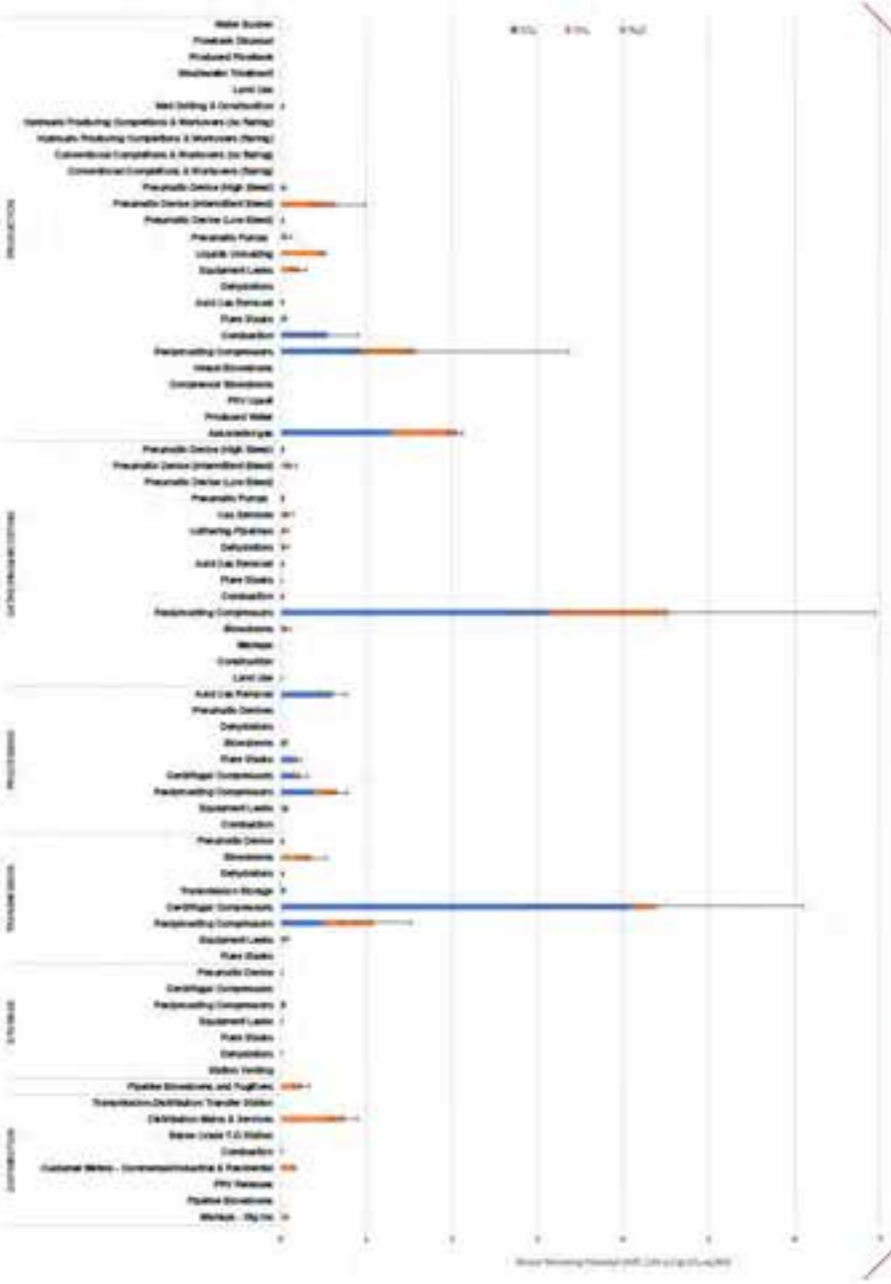
Key drivers of GHG emissions results for the entire natural gas supply chain are illustrated in Exhibit 2-5 (NETL, 2019). Pneumatic devices and compression systems represent a significant portion of the total life cycle GHG emissions associated with the natural gas supply chain (NETL, 2019). Pneumatic devices are used to operate level controllers, valves, and other equipment at natural gas facilities. According to EPA's GHGI, production pneumatics emitted 1,060 kilotons of CH_4 in 2017, accounting for 16 percent of the total CH_4 emissions from the natural gas supply chain. Pneumatic device activity is concentrated at production facilities and there were 833,000 pneumatic devices used by U.S. production facilities in 2019 (NETL, 2019).

Natural gas is compressed for transport from processing facilities to end-consumers. As such, upstream GHG emissions are sensitive to pipeline distances and the number of compressors along these pipelines that the natural gas must pass through. The energy intensity of compression and the fugitive CH_4 emissions from compressors both contribute to upstream GHG emissions (NETL, 2019).

In addition to being a source of CH_4 emissions, compressors are also a source of CO_2 emissions. Most compressors in the U.S. pipeline transmission network are powered by natural gas that is withdrawn from the pipeline itself. Electric motors are not widely used by natural gas pipelines but are installed where local emission regulations limit the use of internal combustion engines or where inexpensive electricity is available. Approximately three percent of compressors used by the natural gas transmission network are electrically driven.

Commented [TS79]: Cite source.

Exhibit 2-5. Detailed GHG emission sources for the U.S. natural gas supply chain

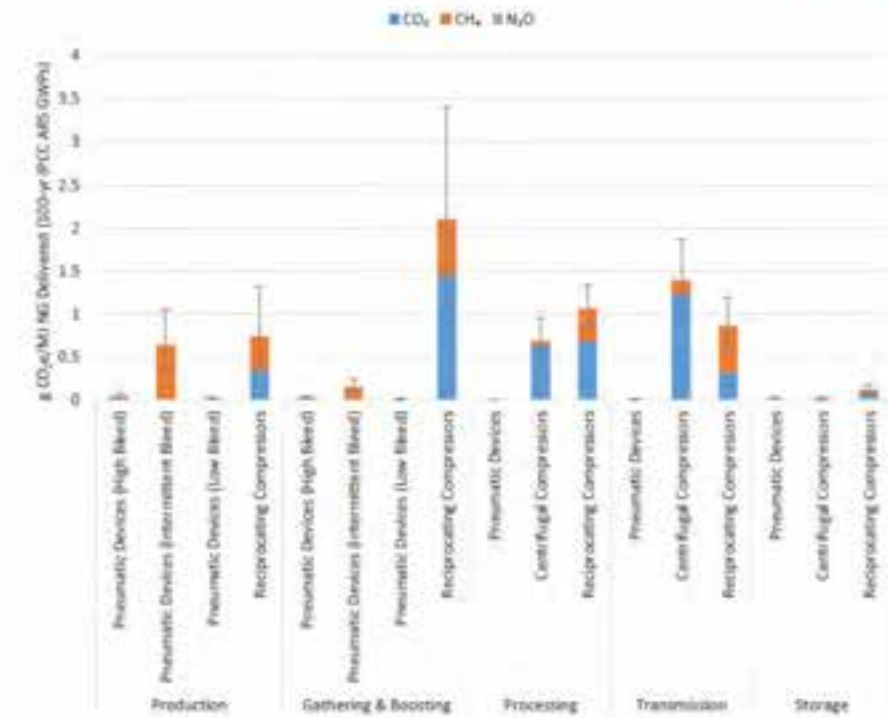


Commented [TS80]: State what year the data represents in the caption and what scope? US average for transmission and distribution combined?

Commented [TS81]: Need higher resolution image.

Two sources of CH_4 emissions from compressor systems include 1) CH_4 that slips through the compressor uncombusted~~ion~~ into the exhaust stream and 2) CH_4 that escapes through compressor seals or packing. Natural gas systems use both centrifugal and reciprocating compressors. Centrifugal compressors are more appropriate for pressure boosting applications in a steady-state applications (such as with a transmission pipeline), while reciprocating compressors are more appropriate when gas flow is variable and when large increases in pressure are required. Centrifugal compressors are typically driven by gas-fired turbines but, in some instances, are driven by an electric motor. Reciprocating compressors are driven by gas-fueled engines. Exhibit 2-6 illustrates the emissions associated with pneumatic devices and compressors.

Exhibit 2-6. GHG emissions from pneumatic devices and compressors across the NG supply chain



For all natural gas production types, the GHG emissions results produced by an LCA are sensitive to production rates and episodic emissions (either liquid unloading or workovers).

Commented [LBD82]: "slips through the compressor uncombusted into the exhaust stream"?

Commented [TS83R82]: Yes.

Commented [TS84]: Exhibit 2-5 and 2-6 units, while the same, are described differently. Exhibit 2-5 is the general standard with the exception of carbon dioxide equivalents are ported as CO2e (subscripted 2) and not as CO2-eq in Exhibit 2.5.

Commented [TS85]: The data does not support this statement. Liquids Unloading is 0.5 g CO2e (Exhibit 2-5)per the life cycle total of 19.9 with a mean uncertainty range of 13.1 to 28.7. The variance in liquids unloading is well within the mean uncertainty range and therefore not a sensitive parameter.

Exhibit 6-8 in the NETL 2019 report provides a ranking of GHG emissions uncertainty (not model sensitivity) but does indicate which sources contribute have an influence on the accuracy of the results.

Results are sensitive to:

- EUR
- Regional natural gas composition differences (dry versus sour gas).
- Compression energy requirements and type.
- Pneumatic device type, frequency, and number of devices per operation.
- Episodic events that result in higher (than normal operations) methane emissions over a short time frame (not a consistent emission source) originating from maintenance and inspection activities or non-standard operator practices.

The above bullet provides a more generic way of describing episodic emissions. My concern was calling out specifically liquids unloading and workovers.

Commented [HSAJ86R85]: Adjust sentence to reflect list provided above.

In addition to its characterization of domestic upstream natural gas, NETL also developed life cycle data for exported LNG, including the GHG emissions from liquefaction, transport, regasification, and ~~the~~ combustion for electricity generation (NETL, 2019).

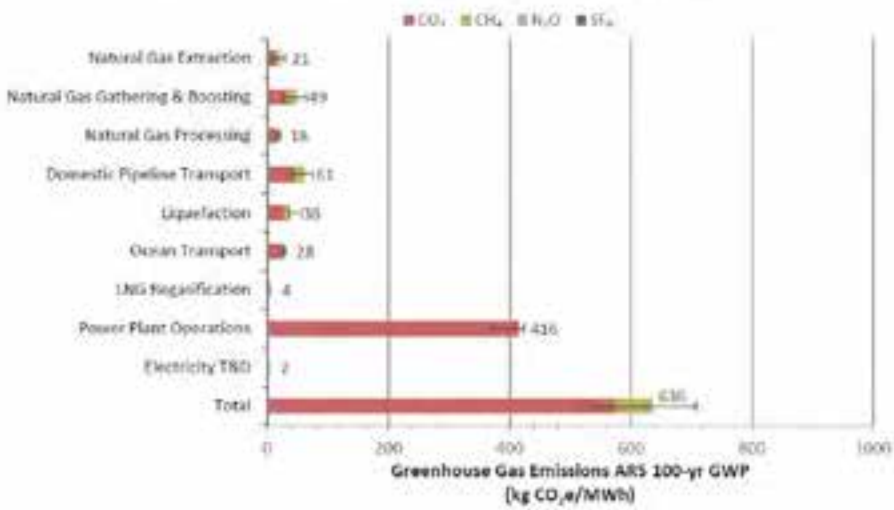
The NETL (2019) report that analyzed the lifecycle emissions of exporting U.S. LNG to Europe yielded the emissions results (assuming end-use in electricity generation) detailed in Exhibit 2-7.

Commented [LBD87]: Is this a separate NETL 2019 report? Or the same one as above? If the same, suggest citing it in full on first mention.

Commented [TS88R87]: Yes a different report.

Commented [LBD89]: Suggest somewhere a comment be made that the supply chain study presented above is "cradle to gate," and excludes end-use, while the LNG study is more truly "cradle to grave," and does include end-use (power generation), meaning extra care should be taken by readers in comparing results and figures.

Exhibit 2-7. GHG emissions from exporting LNG from the United States to Europe



Littlefield, Rai, and Skone (2022) show that geography matters in terms of the GHG emissions estimated for the global natural gas supply chain~~,~~ – where natural gas is produced and ultimately used plays a tremendous role in the total amount of GHG emissions estimated for the supply chain. ~~As such~~Accordingly, a national average value is not necessarily an adequate representation of an individual (source to sink) natural gas supply chain. Littlefield, Rai, and Skone (2022) provide a detailed life cycle perspective on GHG emissions variability where natural gas is produced and where it is delivered. They disaggregate transmission and distribution infrastructure into six regions, balance natural gas supply and demand locations to infer the likely pathways between production and delivery (estimated via modeling as actual tracking of natural gas from well to customer is not technically feasible), and incorporate new data on distribution meters. They find the average transmission distance for U.S. natural gas is 815 kilometers (km) but ranges 45–3,000 km across estimated production-to-delivery pairings examined (Littlefield, Rai, and Skone, 2022). In terms of total GHG emissions, their results suggest the delivery of 1 MJ of natural gas to the Pacific region has the highest mean life cycle GHG emissions (13.0 g CO_2e/MJ) and the delivery of natural gas to the Northeastern region of the United States has the lowest mean life cycle GHG emissions (8.1 g CO_2e/MJ).

Commented [TS90]: This report does not discuss global natural gas supply sources?

I think you mean US.

Commented [LBD91]: How does this compare with other analyses we rely on? Do we rely on national averages elsewhere

In 2020, NETL collaborated with industry and published an analysis of Our Nation's Energy Future's (ONE Future) portfolio of assets (Rai et al., 2020). ONE Future is a natural gas industry partnership dedicated to improving the efficiency of the domestic natural gas supply chain. ONE Future represents 1–13 percent of total throughput in the respective segments of the natural gas industry supply chain. The expected life cycle CH_4 emission rate for ONE Future average natural gas is 0.76 percent (with a 95 percent mean confidence interval ranging 0.49–1.08 percent).

The expected life cycle CH_4 emission rate for the U.S. average scenario is 1.06 percent. In terms of IPCC 100-year GWP, the ONE Future and U.S. average scenarios emit 9.7 and 14.1 g CO_2e/MJ of delivered natural gas, respectively.

2.3 Other Natural Gas Analyses

Balcombe et al. (2016) document the wide range of CH_4 emissions estimates across the natural gas supply chain. Estimates of combined CH_4 and CO_2 emissions range 2–42 g CO_2e/MJ. A ~~s~~Significant drivers of this wide range of projections are 1) the emissions associated with upstream natural gas production, and 2) whether the natural gas is ultimately converted to LNG or not. This sub-section explores these different segments of the supply chain.

2.3.1 Natural Gas Production Analyses

Several studies have found that CH_4 emissions from the natural supply chain are about 1.5–2.5 times the amount reported in EPA's GHGI (Rutherford et al., 2021; Alvarez et al., 2018; Balcombe et al., 2016). Much of the discrepancy can be attributed to differences in the analyses performed for the production segment of the natural gas supply chain where super emitters and emissions-intensive equipment are both prevalent (Rutherford et al., 2021; Alvarez et al., 2018; Balcombe et al., 2016).

To isolate specific sources of disagreement between EPA's GHGI and other studies, Rutherford et al. (2021) reconstruct EPA's GHGI emission factors, beginning with the underlying datasets, and uncover some possible sources of disagreement between inventory methods and top-down studies. The adjusted emissions factors are direct inputs in the Rutherford et al. (2021) study outputs. Rutherford et al. use~~s~~ a bottom~~s~~-up measurement approach, yet the approach differs from the GHGI in that it applies a bootstrap resampling statistical approach to allow for inclusion of infrequent, large emitters, thus robustly addressing the issue of super-emitters in a more robust way.

Rutherford et al. (2021) estimate the mean, production-normalized emissions rate from the production segment as 1.3 percent (1.2–1.4 percent at 95 percent confidence interval, based on gross natural gas production of 32 Tcf and an average CH_4 content of 82 percent), slightly lower than Alvarez et al., 2018) who estimate it at 1.4 percent. Rutherford et al. (2021) estimate mean natural gas production-segment CH_4 emissions as equal to 6.6 teragrams (Tg) per year (6.1–7.1 Tg per year, at 95 percent confidence interval). Both the results of Rutherford et al. (2021) and Alvarez et al. (2018) are approximately two times larger ~~the~~ than estimates of the 2015 EPA

Commented [LBD92]: Comment applicable to other sections as well – is text being updated with more recent studies? (apologies if updating is ongoing in some sections and I'm not aware of it) Most or all of these studies (aside from NETL's) are >10 years old.

Commented [LBD93]: Comment applicable to other sections as well – is text being updated with more recent studies? (apologies if updating is ongoing in some sections and I'm not aware of it) Most or all of these studies (aside from NETL's) are >10 years old.

GHGI, which suggests that 3.6 Tg of emissions per year (year 2015 data, excludes offshore systems) come from the natural gas production segment.

Importantly, the difference in U.S. production-segment emissions estimates between the Rutherford et al. (2021) study and EPA's GHGI is approximately the same volume as Rutherford et al. (2021) study estimate of the contribution from super-emitters (top 5 percent of emissions events). Given that Rutherford et al. (2021) results match the Alvarez et al. (2018) site-level results, the former concludes that the divergence between the GHGI and top-down/site-level studies is not likely to be due to any inherent issue with the bottoms-up approach. A results comparison of the Rutherford et al. (2021) study, the Alvarez et al. (2018) study, and 2015 EPA GHGI data can be found illustration in Exhibit 2-8.

Commented [TS94]: This sentence seems to conflict with the 2.5 times difference between Rutherford and EPA?

I am not sure I am interpreting your point correctly.

Also, what year does the data represent in the EPA GHGI to Rutherford comparison?

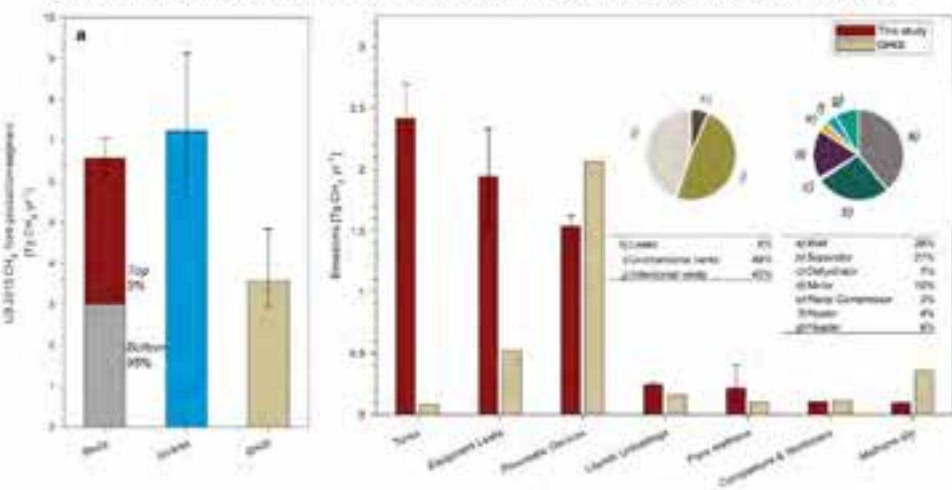
Commented [HSAJ95R94]: Revise sentence.

Commented [TS96]: If this is 2015 data, is this still a current perspective of the industry performance?

Does the latest EPA GHGI still result in this conclusion?

Commented [HSAJ97R96]: Is the comparison still accurate? If we cannot find a more contemporary comparison, should we make a statement on them? Suggest framing the discussion that updates have been made by EPA, etc. Adjust framing.. Softening context.

Exhibit 2-8. Comparison of GHG Emissions Results from Rutherford et al., Alvarez, et al., and EPA GHGI



Permission pending from Rutherford et al. (2021)

2.3.2 LNG Studies

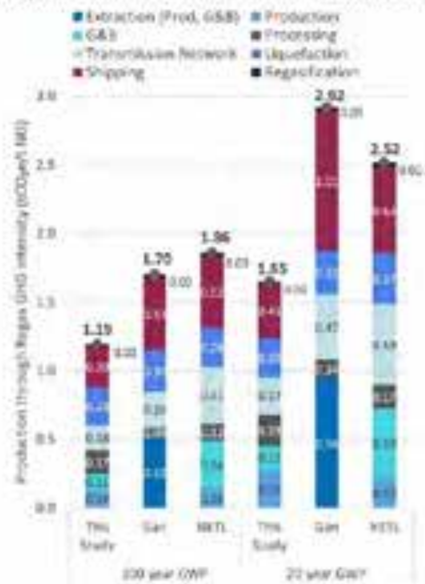
Commented [LBD98]: Comment applicable to other sections as well – is text being updated with more recent studies? (apologies if updating is ongoing in some sections and I'm not aware of it) Most or all of these studies (aside from NETL's) are >10 years old.

Relative to traditional natural gas supply chains where pipelines are ~~primarily~~ the primary means by which natural gas is transported, LNG supply chains also involve liquefaction, shipping, and regasification stages ach of ~~which~~ these stages drive even greater variability in emissions profiles in LCA studies. A review of 37 global LNG supply scenarios between the United States and China by Gan et al. (2020) concluded that GHG emissions intensities varied by about 150 percent. Abrahams et al. (2015) note that emissions from the shipping of LNG exports from the United States to ports in Asian and European markets account for only 3.5–5.5 percent of precombustion life cycle emissions; hence, shipping distance is not a major driver of GHGs in the LNG supply chain.

Commented [LBD99]: Does this mean +/- 150%? Or something else?

At the end of 2020, Cheniere Energy was the largest exporter of LNG from the United States in terms of volume. Roman-White et al. (2021) developed an LCA framework to estimate GHG emissions representative of Cheniere's LNG supply chain, considering both upstream and downstream sources of emissions from Cheniere's Sabine Pass Liquefaction facility, using supplier-specific data collected from wellhead through ocean transport. Roman-White et al. (2021) compare the GHG emissions intensity of Cheniere LNG to two similar assessments of emission intensity from U.S. LNG transported to China (Gan et al., 2020; NETL, 2019). The results of their comparison are illustrated in Exhibit 2-9.

Exhibit 2-9. Comparison of GHG emissions results from Roman-White et al., Gan et al., and NETL



Used with permission from Roman-White et al. (2021)

The NETL (2019) LNG study uses more recent production emission data (2016 data) than Gan et al. (2020). The study is based on natural gas production in Appalachia with relatively low emissions intensity. The NETL analysis differs from the Roman-White et al. study primarily in the intensity of the G&B and transmission stages, which are driven by differences in individual facility performance.

Commented [LBD100]: Which study? Roman-White or NETL?

When modeling transmission compression, the NETL (2019) study assumes a factor of 0.97 horsepower-hour (HPh)/thousand cubic feet (Mcf) to estimate the transmission station throughput (derived from NETL-published parameters). The average ratio of HPh to Mcf of throughput, from Cheniere's known suppliers (used in the Roman-White et al. study) is 0.27 HPh/Mcf, which is based on supplier data collection completed. For modeling gas from other transmission operators, the GHGRP does not publicly provide the throughput of compressor stations. ~~As such, t~~The Roman-White et al. (2021) study assumes 0.29 HPh/Mcf based on data reported by EIA.

The higher factor used by the NETL (2019) study results in increased modeled fuel consumption across the transmission network. The Roman-White et al. liquefaction GHG intensity is 8–13 percent less than the intensity estimated by Gan et al. and is comparable to the NETL (2019) study estimate on a 100-year basis. The Roman-White et al. (2021) study concludes ocean transport stage emission intensity is 42–60 percent less than the transport emission intensity of Gan et al. (2020), and 35–42 percent less than that of the NETL (2019) study.

Jordaan et al. (2022) estimate~~s~~ ~~the~~ global average life cycle GHG emissions from the delivery of gas-fired electricity to be 645 gCO_2e per kilowatt hour (kWh) (334–1,389 gCO_2e per kWh), amounting to 3.6 gCO_2e yr−1 in 2017 (10 percent of energy-related emissions). This result is within range of the results obtained by Roman-White et al. (2021), who report life cycle GHG emissions of 524 gCO_2e kWh for electricity in China from LNG supplied by U.S. LNG exporter Cheniere, and 636 gCO_2e per kWh reported by NETL (2019).

Cai et al. (2017) assess GHG emissions of using compressed natural gas and LNG as transportation fuels by three heavy-duty natural gas vehicles types from a wells-to-wheels perspective. Cai et al. that natural gas vehicle wells-to-wheels GHG emissions are largely driven by the vehicle fuel efficiency, as well as CH_4 leakage rates of both the NG supply chain and vehicle end use; the study estimates wells-to-wheels GHG emissions of natural gas vehicles to be slightly higher than those of the diesel counterparts given the estimated wells-to-wheels CH_4 leakage.

2.4 Mitigation Measures

Compressor seals include ~~the~~ wet seals used by ~~the~~ centrifugal compressors and ~~the~~ rod packing used by reciprocating compressors. Wet seals surround the rotating shaft of a centrifugal compressor with oil, which prevents gas leakage from the compressors. The oil used by wet seals must be continuously regenerated, which releases CH_4 into the atmosphere. By replacing wet seals with mechanical dry seals, the CH_4 emissions from centrifugal compressors can be reduced.

Reciprocating compressors prevent CH_4 leakage by encasing each compressor rod with a set of oil-coated, flexible rings. Proper maintenance and routine replacement of these rings prevents unnecessary leakage of CH_4. Storage tanks hold flowback water and liquid hydrocarbons recovered from the production stream. Variable loading levels and temperatures cause the venting of CH_4 and other gases from these tanks. By installing vapor recovery units on storage tanks, producers can more effectively reduce emissions from natural gas production. The captured emissions can be combusted on site to provide process energy, or they can be channeled to the sales stream.

Pneumatic controllers use gas pressure to open and close valves throughout a natural gas production and processing system. Natural gas is commonly used to pressurize pneumatic control systems. The bleeding of natural gas from pneumatic controllers leads to venting CH_4 to the atmosphere. The GHG impact of pneumatic control systems can be reduced by installing pneumatic systems that use pressurized air instead of pressurized natural gas.

Commented [LBD101]: This paragraph seems a little bit tacked-on. Consider adding context or possibly deleting.

Commented [LBD102]: Consider adding an introductory sentence or paragraph with an overall statement about types of mitigation measures discussed in this section.

Commented [TS103R102]: Agree to delete this paragraph and replace with a concluding paragraph for Section 2.3. What is the takeaway message from all of these reports and data?

Commented [LD104R102]: Note to reviewers - I think Tim's response here goes with the comment above – regarding the current last para of section 2.3

Since ~~the~~ regulations focus on reduced emissions completions (RECs), they are more applicable to unconventional wells. RECs employ~~use~~ equipment that allow the capture of gas during flowback, either to be sent to the product line or, if this is not feasible, to be flared. However, ~~the~~ regulations also mandate emission reductions from pneumatically controlled valves and compressor seals, which are two types of emission sources common to conventional and unconventional natural gas technologies. Lastly, ~~F~~flowback emissions are governed by whether RECs are used or not.

The data suggest that the use of this equipment reduces completion emissions by approximately 75–99 percent. For the most established unconventional gas industry, the United States, the use of RECs is compulsory. However, once RECs are employed and CH_4 is flared to some degree, resultant CO_2 emissions from flaring may become significant (Balcombe, 2016).

A~~n~~ NETL (2020) report notes that compressed-air pneumatics are a mature technology that reduces CH_4 emissions from pneumatic systems. The technology replaces existing devices, which are actuated by natural gas, with devices that are actuated with compressed air. This requires the addition of electric-powered air compressors at natural gas facilities but can result in zero CH_4 emissions from pneumatics. A barrier to implementation of compressed-air pneumatics is electricity availability. The United States has an extensive electricity grid, but grid connections are not always near production sites. The same NETL (2020) report notes that proven technologies exist for reducing CH_4 emissions from compression systems (as described below):

- Centrifugal compressors emissions can be reduced by replacing wet seals with dry seals. These seals are used around the rotating shaft of the compressor and prevent high pressure gas from escaping the compressor. Wet seals involve the use of recirculating oil that emits 40–200 standard cubic feet (scf) of natural gas per minute (min). Dry seals use gas to seal the compressor shaft and emit only 6 scf/min. The replacement of wet seals with dry seals reduces centrifugal compressor emissions by 85–97 percent.

- Reciprocating compressor emissions can be reduced by replacement of rod packing. Packing prevents gas from moving around piston rods and escaping the compression cylinder. New packing that is properly installed on a well-maintained compressor will emit about 12 scf/hour. The emission rate for old or poorly installed packing can range 25–67 scf/hour. When compared to the emission rate for new packing, this equates to potential emission reductions of 52–82 percent. Rod packing replacement is a mature technology, but there are new technologies that can also reduce reciprocating engine exhaust slip. These new technologies include advanced materials that increase piston rod service life while reducing rod wear and Teflon-coated rings that reduce friction while maintaining a tight seal. There are no data currently available, however, on the emission reduction potential tied to deploying~~s~~ ~~of~~ these new technologies.

- The majority of the CH_4 emissions from reciprocating compressors are due to the CH_4 slip from engine exhaust. Comparing the exhaust emission factors for rich burn and lean burn engines, respectively, shows that [illegible] burn engines have a combustion effectiveness of 97 percent and lean burn engines have combustion effectiveness of 99

Commented [LBD105]: Which regulations? Suggest explain why they are being mentioned here.

Commented [LBD106]: It may be confusing that this is the name of "equipment." Suggest a little explanation if possible.

Commented [TS107]: RECs are required by law now this not a current issue for the industry. The point that REC implementation has shifted the emissions from methane to CO2 has occurred and did reduce GHG intensity form a global warming perspective.

Commented [HSAJ108R107]: Make clear its mandatory.

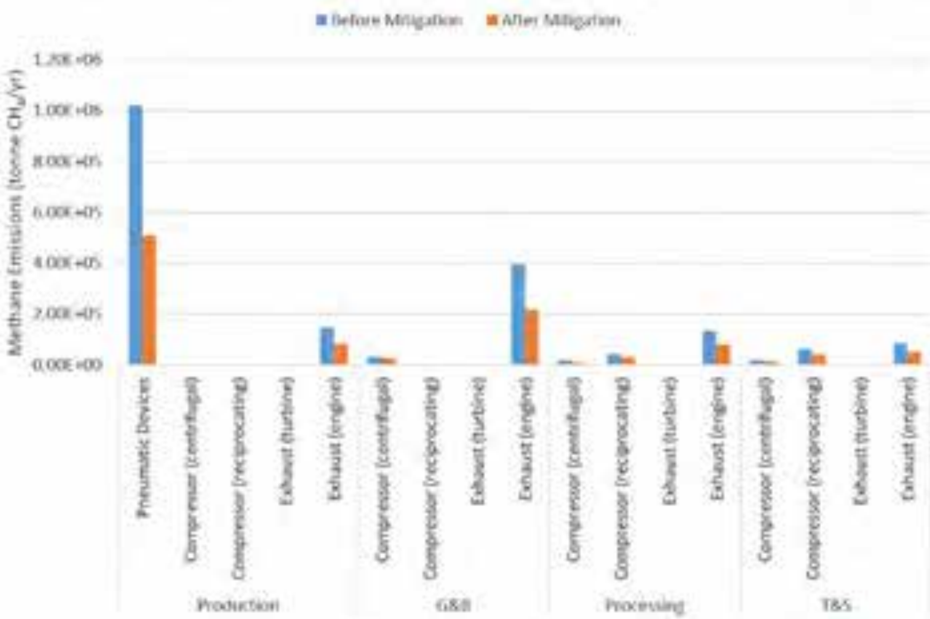
Commented [EK109]: NETL Team - with this proposed text correction, is the statement now accurate?

percent. Air-fuel-ratio controls are an option for improving the combustion effectiveness of lean burn engines while keeping NOx emissions low. More research is required to understand the limits of air-fuel-ratio controls but, for this analysis, it is assumed that they can increase the combustion effectiveness of a lean burn engine by 97–99 percent.

Exhibit 2-10 illustrates the impact of these mitigation approaches.

Exhibit 2-10. Illustration of mitigation measure impact for pneumatic devices and compressors

Commented [TS110]: What is the source? If this the ONE Future report, it was limited to the ONE Futures value chain and not the US average.



Balcombe et al. (2018) note that pre-emptive maintenance and a faster response to ~~high~~ detection of high emissions, ~~detection~~ are methods for reducing the impact of super emitters. Identifying a cost-effective solution is imperative and much attention is being given to developing lower cost emission monitoring and detection equipment. As Brandt et al. (2016) point out, identifying larger leaks from the highest emitters may be carried out using less sensitive, and consequently cheaper, detectors in areas at the highest risk.

Alvarez et al. (2018) note that key aspects of effective mitigation include pairing well-established technologies and best practices for routine emission sources with economically viable systems to rapidly detect the root causes of high emissions arising from abnormal conditions. The latter could involve combinations of current technologies, such as on-site leak surveys by company personnel using optical gas imaging, deployment of passive sensors at individual facilities or mounted on ground-based work trucks, and in situ remote-sensing approaches using tower networks, aircraft, or satellites. Over time, the development of less failure-prone systems would be expected through repeated observation of and further research into common causes of abnormal emissions, followed by reengineered design of individual components and processes.

With respect to liquefaction, Mokhatab et al. (2014) note that most of the plant energy consumption and resultant emissions in natural gas liquefaction facilities occur in the compressor drivers, where fuel energy (usually natural gas) is converted to mechanical work (or electricity in case of electrically driven compressors). Due to the energy consumption scale of the LNG plants, any enhancement to the energy efficiency of a plant will result in a significant reduction in gas consumption and consequently CO_2 emissions (Mokhatab et al., 2014).

There are two ways to increase the energy efficiency of LNG plants: 1) liquefaction cycle enhancement and 2) driver cycle enhancement. Liquefaction cycle enhancements reduce ~~the~~ compressor power and consequently the compressor driver's fuel consumption. Driver cycle enhancement reduces the amount of fuel consumption to generate a specific amount of power. Typical fuel sources for natural gas liquefaction cycles include either pure refrigerant in cascade cycles, expansion-based cycles, or mixed refrigerant cycles.

Pure refrigerant cycles have a constant evaporating temperature that is a function of the saturation pressure. Mixed refrigerant cycles do not maintain a constant evaporating temperature at a given pressure. Their evaporating temperature can range and change depending on the pressure and composition. A refrigerant mixture of hydrocarbons and nitrogen is chosen so that it has an evaporation curve that matches the cooling curve of the natural gas with the minimum temperature difference. ~~As such~~Therefore, small temperature differences reduce entropy generation, and, thus, improve thermodynamic efficiency, reduce power consumption, and reduce the emissions associated with liquefaction facilities (Mokhatab et al., 2014).

A study from Pospíšil et al. (2019) notes that a certain part of the energy spent on liquefaction can be recovered by the utilization of the cold stream from LNG. The amount of usable cold is given by thermophysical properties of natural gas and corresponds to 830 kilojoule (kJ)/kg of LNG. This cold energy can be recovered during the regasification process. Regasification is carried out either in port terminals before natural gas is transported via gas lines or directly before the use of natural gas. The exploitation of cold from LNG is quite limited at present. Most of the available cold is wasted during the regasification process when LNG is heated up by water or ambient air. Inefficient use of cold temperature streams reduces the overall efficiency of this primary energy source and leads to greater emissions. Promising ways of utilizing cold from LNG in the regasification process should be explored and implemented (Pospíšil et al., 2019). For LNG that is ultimately combusted for electricity, Jordaan et al. (2022) find that deploying mitigation options can reduce global emissions from gas-fired power by 71 percent with carbon capture and storage, CH_4 abatement, and efficiency upgrades contributing 43 percent, 12 percent, and 5 percent, respectively—and this suggested mitigation falls within national responsibilities, except an annual 20.5 $MtCO_2e$ of ocean transport emissions generated.

Roman-White et al. (2021) note that for LNG, harmonized data collection and reporting would build confidence in supplier claims about LCA emissions, enabling comparisons between natural

Commented [LBD111]: Suggest explain this term

Commented [LBD112]: Can you add a parenthetical example?

Commented [TS113]: This reads like an NETL statement. When quoting another others recommendations or key conclusions, it would help if the text read

Pspeisel et al. 2019 recommends....

Universal comment to ensure clarity on who's recommendations or findings are being discussed.

Commented [LBD114]: Do you mean aggregate emissions in the world? Or GHG emissions?

Commented [EK115]: Please add CCS to the Acronym List.

Commented [LBD116]: Unclear what this means gas supply chains and supporting climate goals for all participants in the supply chain. This could stimulate a virtuous cycle of demand for GHG accounting and reduction and provision of more granular, company-specific emissions estimates.

MacKinnon et al. (2018) demonstrate that natural gas-fired power generation and the natural gas system could play several important roles in supporting sustainable energy strategies over time that can achieve societal GHG reduction goals and help the transition to renewable sources. Natural gas generation can support transitions to renewable resources 1) by use in advanced conversion devices to provide complementary grid services efficiently and with very low emissions to maximize the benefits of intermittent renewable resources (e.g., running a natural gas compression system during peak renewables production), and 2) natural gas generation and the existing natural gas infrastructure can support the use of renewable natural gas with high energy and environmental benefits.

Commented [LBD117]: A term like "natural gas-fired power generation" might be more clear.

According to Stern (2022), three major requirements for creating credible measuring, reporting, and verification of CH_4 emissions are 1) to move measurement and reporting of CH_4 emissions from standard factors—either engineering-based or from EPA data—to empirical (Tier 3) measurements, and to reconcile bottoms-up (ground level) and top-down (satellite/aircraft/drone) observations; 2) to ensure that data measurement and reporting has been verified and certified by accredited bodies; and 3) to require asset-level emissions data to be transparent and publicly available. Failure to do so on grounds of commercial confidentiality risks being interpreted as evidence that the data is not credible.

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3 AIR QUALITY

The natural gas supply chain contributes to air pollution in several ways, including 1) the leaking, venting, and combustion of natural gas during production and 2) the combustion of natural gas and other fossil fuel resources or other emissions during associated operations (e.g., extraction, transportation, downstream combustion). Emissions sources include pad, road, and pipeline construction; well drilling, completion, and flowback activities; and natural gas processing and transmission equipment such as controllers, compressors, dehydrators, pipes, and storage vessels. Pollutants include, most prominently, CH_4 and volatile organic compounds (VOCs)—of which the natural gas industry is one of the highest-emitting industrial sectors in the United States—in addition to nitrogen oxides , sulfur dioxide (SO_2), and various forms of other hazardous air pollutants (HAPs) (Congressional Research Service [CRS], 2020). Pollutants are described in detail below (CRS, 2020):

- CH_4 is the principal component of natural gas and is a precursor to ground-level ozone formation (i.e., "smog").
- NOx is a ground-level ozone precursor. Significant amounts of NOx are emitted during the combustion of natural gas and other fossil fuels (e.g., diesel). The combustion of natural gas occurs when it is flared during drilling and well completions and when used to drive the various compressors that move products through the system. Combustion also occurs in engines, drills, heaters, boilers, and other production equipment.
- VOCs are a ground-level ozone precursor. The crude oil and natural gas sector is currently one of the largest sources of VOC emissions in the United States, accounting for approximately 20 percent of man-made VOC emissions nationwide (and representing almost 40 percent of VOC emissions released by stationary sources). VOCs—in the form of various hydrocarbons—are emitted throughout a wide range of natural gas operations and equipment. The interaction among VOCs, NOx, and sunlight in the atmosphere contributes to the formation of ozone.
- SO_2 is emitted from crude oil and natural gas production and processing operations that handle and treat sulfur-rich, or "sour," gas.
- HAPs, also known as air toxins, are those pollutants that are known or suspected to cause cancer or contribute to other serious health effects including reproductive issues and birth defects. Of the HAPs emitted from natural gas systems, VOCs are the largest group and typically evaporate easily into the air. The most common HAPs produced from natural gas systems are n-hexane and benzene, toluene, ethylbenzene, and xylenes (BTEX) compounds. Some natural gas reservoirs may also contain high levels of hydrogen sulfide (H_2S). HAPs are found primarily in natural gas itself and are emitted from equipment leaks and during processing, compressing, transmission, distribution, or storage operations. HAPs are also a byproduct of incomplete fuel combustion and may be components in various chemical additives.

Commented [LBD118]: "exploration and production"? Are we including exploration?

Commented [EK119]: Please add Nox to the Acronym list.

Commented [LBD120]: Suggest explain in parens or a footnote what compounds this represents

3.1 UPSTREAM PRODUCTION AND HYDRAULIC FRACTURING

The venting of natural gas during extraction and processing is a key source of VOC emissions. Similar to CH_4, VOCs are a naturally occurring constituent of natural gas and can react with other pollutants to produce ground-level ozone.

Emissions of VOCs and CH_4 are lower for offshore conventional production compared to other types of natural gas types because offshore platforms generally have higher production rates helping to justify capital expenditures on loss reduction technologies, which help to prevent unnecessary venting.[h] Another source of VOC emissions during upstream operations is venting from condensate storage tanks, which occurs in regions with wet gas.[i]

Commented [TC121]: Is the a reference for this finding? I would have thought safety at offshore platforms also would have driven lower emission rates.

If we don't have a reference or more supporting documentation, I think the sentence could be deleted without impacting the narrative.

Commented [HSAJ122R121]: Offshore lower profile is due to greater safety measures needed to manage greater risks.

Commented [LBD123]: Suggest explain wet gas vs. dry gas

Commented [SW124R123]: I think that would be helpful.

Commented [SH125R123]: Included as footnote.

The combustion of natural gas in compressors and gas processing equipment produces NOx and carbon monoxide (CO). Similarly, the combustion of diesel in drilling equipment produces NOx and CO, as well as significant quantities of SO_2 emissions. Beyond VOCs, CH_4, NOx, CO, and SO_2 emissions, upstream processes can also produce aliphatic hydrocarbons, (e.g., C2–C5), alkanes, VOCs (e.g., BTEX), H_2S, n-hexane, and formaldehyde, which can contaminate ambient air (Wollin et al., 2020).

Elliott et al. (2017) estimates that up to 143 air contaminants can be released during hydraulic fracturing. The International Agency for Research on Cancer generates hazard assessments for only 20 percent of these identified contaminants. Twenty of these air contaminants are known carcinogens. Other air contaminants are generated by the peripheral plant components. These include particulate matter, NOx, precursors of ozone and polycyclic aromatic hydrocarbons (Wollin et al., 2020).

The following activities are known to contribute to air contamination at oil or gas drilling sites:

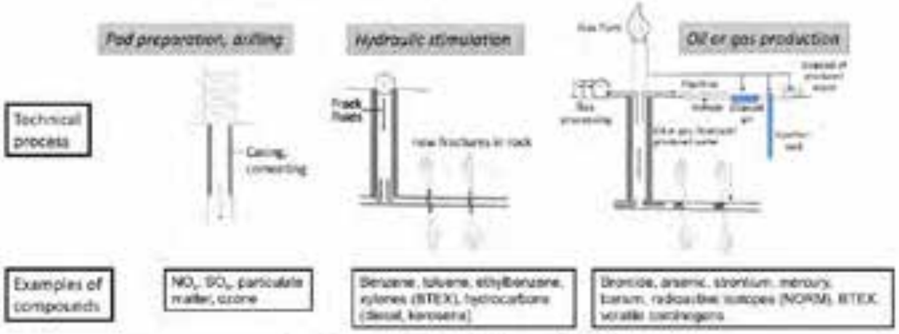
- Preparation of the drilling site including road connections
- Drilling of the well
- Truck traffic for delivery and disposal of materials
- Removal of acid gases and water from gas; separation of natural gas from other hydrocarbons
- Operation of compressor stations to enable the transport of natural gas into transport pipelines
- Preprocessing of crude oil prior to refinery

Exhibit 3-1 illustrates the supply chain for natural gas where each of these activities occurs (Wollin, 2020).

[h] There are no technological barriers to applying such emission reduction technologies to shale gas or other sources of natural gas.h

[i] When natural gas is retrieved, it can be considered wet or dry. Dry natural gas is at least 85 percent methane, but often more. Wet natural gas contains some methane, but also contains liquids such as ethane, propane or butane. The more methane natural gas contains, the "dryer" it is considered.

Exhibit 3-1. Illustration of supply chain steps where upstream air pollution occurs



Permission pending from Wollin et al. (2020)

NOx and SOx emissions have been reported to be higher during the development of the drilling site compared to during the production phase (Wollin et al., 2020). Similar observations have been made for particulate matter (PM) (e.g., PM2.5 and PM10). Analysis of shale gas production sites in North Texas showed an increase in ozone concentrations by 8 percent at natural gas production sites compared to control sites (Wollin et al., 2020).

Indirect energy consumption can also affect the air quality profile of gas extraction technologies. If the development or operation of a natural gas well uses grid electricity, then the fuel mix of the electricity grid will affect the life cycle performance of the well. The indirect air quality impacts of electricity consumption depend on the fuel mixes and combustion characteristics of power plants that compose a regional electricity grid.

A critical aspect concerning emissions from hydraulic fracturing processes is that several of the organic toxic compounds that are emitted are not regulated. EPA's National Ambient Air Quality Standards only places limits on six Criteria Air Pollutants including CO, ozone near the surface, NOx, PM, SO_2, and lead. Since the N do not place limits on nor consider the effects of organic compounds beyond those listed previously, EPA's Integrated Risk Information System is frequently used to identify and characterize the health hazards of other compounds. Unlike , the Integrated Risk Information System does not place any legal restrictions on the release of the compounds it provides data on. ~~As such~~ ~~Therefore, national regulations for the breadth of air emissions released during hydraulic fracturing are insufficient~~. Exhibit 3-2 offers a perspective on non-GHG air pollutant by supply chain step or equipment.

Commented [TC126]: I'm not following the discussion in this paragraph.

Air toxics, or hazardous air pollutants (HAPs), are regulated by EPA under the NESHAP (https://www.epa.gov/stationary-sources-air-pollution/oil-and-natural-gas-production-facilities-national-emission). Would the organic toxic compounds discussed here be regulated under the NESHAP?

Commented [EK127R126]: Agreed. I'm slightly confused as well. After NETL provides clarification, please add NAAQS to the acronym list.

Commented [HSAJ128R126]: Add more context to sharpen discussion.

Commented [LBD129]: "Incomplete"?

Commented [TC130]: Does Exhibit 3-2 use EPA's Integrated Risk Information System? I don't understand the connection between the Integrated Risk Information System and the other statements in this paragraph or the Exhibit.

Exhibit 3-2. Perspective of non-GHG air pollutant by supply chain step or equipment

Source	Air pollutant				Data quality
	NO_x	VOC	PM	Other toxic substances	
Well development					
Drilling rigs	•	+	•	•	Medium
Frac pumps	•	+	•	•	Medium
Truck traffic	•	+	•	•	Medium
Completion venting		•		•	Poor
Frac ponds		+			Poor
Gas production					
Compressor stations	•	•	+	•	Medium
Wellhead compressors	+	+	+	+	Medium
Heaters, dehydrators		+	+	+	Medium
Blowdown venting		+		+	Poor
Condensate tanks		•		+	Poor
Fugitives				+	Poor
Pneumatics		+		+	Poor

• Major source, + minor source

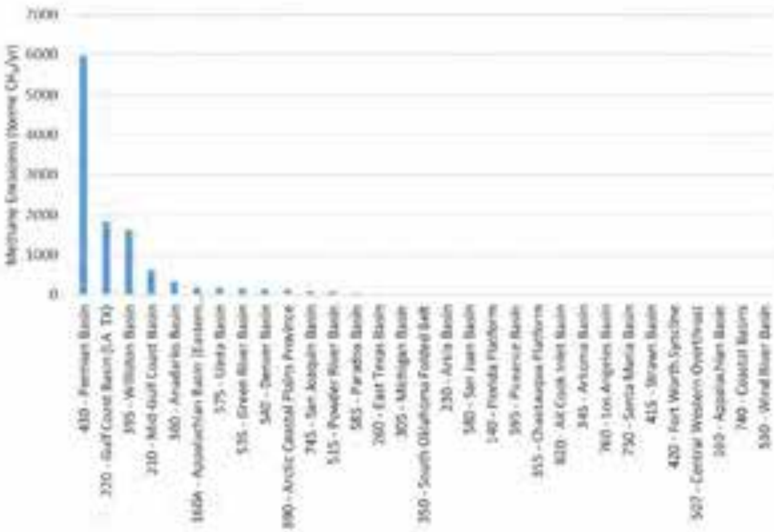
Permission pending from Wollin et al. (2020)

McMullin et al. (2018) analyzed exposure to VOCs emitted during hydraulic fracturing in Colorado. They identified 56 different VOCs that were emitted during hydraulic fracturing using data ~~they~~ compiled from 47 existing air monitoring devices that measured these VOCs at 34 different locations across the region.

Plant et al. (2022) used airborne sampling to measure flare efficiency[i] in three major gas production regions in the United States. They found that both unlit flares and inefficient combustion contribute comparatively to ineffective CH_4 destruction, with flares effectively destroying only 91.1 percent (90.2–91.8 percent; 95 percent confidence interval) of CH_4 emissions. Other emissions from flaring can include carbon particles (soot), unburned hydrocarbons, CO, partially burned and altered hydrocarbons, NOx, and (if sulfur containing material such as H_2S or mercaptans is flared) SO_2. The combustion products of flaring at natural gas production and processing sites specifically include CO_2, CH_4, and N_2O. Exhibit 3-3 illustrates the annual methane emissions from flaring for U.S. production basins (NETL, 2020).

i The flare efficiency is a measure of the effectiveness of the combustion process to fully oxidize the fuel. When inefficiencies occur, unburned fuel, CO, and other products of incomplete combustion (e.g., soot, VOCs, etc.) are emitted into the atmosphere.

Exhibit 3-3. Annual CH_4 emissions from flaring for U.S. production basins



3.2 MIDSTREAM TRANSPORT EMISSIONS

While the presence of HAPs in unprocessed, upstream natural gas has been documented, little has been published on their presence in the midstream segments of the natural gas supply chain. Nordgaard et al. (2022) systematically evaluated publicly available, industry-disclosed HAP composition data from natural gas infrastructure applications submitted to FERC between 2017 and 2020. These applications covered 45 percent of the U.S. onshore natural gas transmission system (as measured by pipeline miles). Given that reporting HAP composition data is not required by FERC, only 49 percent of approved projects disclosed their HAP composition data to FERC. Of the applications that did disclose their HAP composition data, HAP concentrations were typically reported as higher for separator flash gas and condensate tank vapor, compared to [illegible] and transmission-grade natural gas, with mean benzene concentrations of 1106, 7050, 77, and 37 parts per million, respectively.

Nordgaard et al. (2022) also identified one pipeline operator that reports real-time HAP concentrations for natural gas at five pipeline interconnection points. Similar to the FERC applications, this operator reported BTEX and H_2S as present in the pipelines used to transport their natural gas. ~~Notably, mercury was also reported as detectable in 14 percent of real-time natural gas measurements but was not reported in any FERC applications.~~ Because current transmission infrastructure releases natural gas during uncontrolled leaks, loss of containment events, and routine operations (e.g., blowouts and compressor station blowdowns), having access to HAP composition data may be ~~critical~~ important for conducting both air quality and health-focused evaluations of natural gas releases.

Commented [TC131]: Recommend deleting this figure or moving to the GHG chapter.

Commented [EK132R131]: If we retain the figure and move it to the GHG chapter, I still have the following concern: given the enormous flaring outlier data from the Permian Basin reflects, if there is positive movement there (in Texas and / or New Mexico, etc.) in terms of new / proposed flaring regulations, sustainable practices voluntarily advanced by key / several operators, etc., I suggest we add that additional context to the text narrative. The flaring problems in the Permian profiled previously by EDF and others influenced European buyers (e.g., French utility Engie back in 2020) who became increasingly concerned with and began to oppose the importation of 'dirty gas' from that massive play.

Commented [ST133R131]: NETL: Move to GHG section or delete.

Commented [HSAJ134R131]: Open to making the point but chart should reflect. Reflect flaring is issue in some basins but not nation wide. Don't want to talk about outliers.

Commented [LBD135]: Would it be desireable to provide specific comment on midstream methane emissions, since methane has been cited as an ozone precursor in addition to being a GHG? Possibly it could be a reference to the chapter on GHGs.

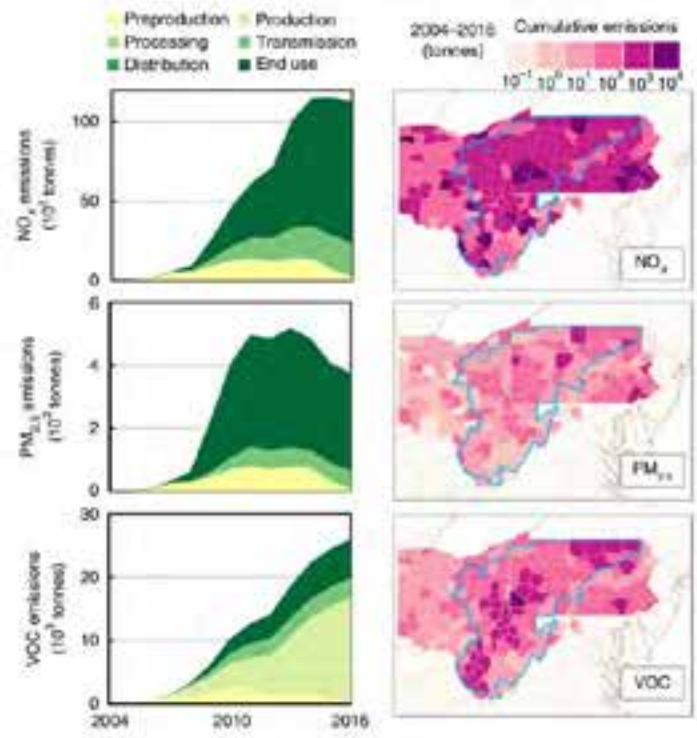
3.3 END-USE PROCESSES

Commented [TC136]: Please delete this section, end use emissions are out of scope. Some of the information about upstream air emission source might be appropriate to move above.

Commented [HSAJ137R136]: End-Use is not within scope so we don't need a discussion. Could remove unless there is something recyclable. If so add to another section.

Mayfield et al. (2019) performed an analysis of the environment impacts associated with the shale gas boom in the Appalachian Basin and found the majority (61 percent) of VOC emissions from the natural gas supply chain can be largely attributed to upstream processes and are spatially concentrated in counties with the highest cumulative production. Upstream processes contribute the most to total NOx (67 percent) and PM2.5 (73 percent) emissions across the natural gas supply chain; NOx and PM2.5 emissions are relatively evenly distributed across counties (Mayfield et al., 2019). Exhibit 3-4 presents annual NOx, PM2.5, and VOC emissions from the natural gas supply chain within Pennsylvania, Ohio, and West Virginia, along with the spatial distribution of cumulative NOx, PM2.5, and VOC emissions by county between 2004 and 2016. It is important to note that the blue lines delineate shale gas-producing counties (Mayfield et al., 2019).

Exhibit 3-4. Annual (left graphs) and cumulative (right graphs) (2004–2016) NOx, PM2.5, and VOC emissions from natural gas supply chain within Pennsylvania, Ohio, and West Virginia



Permission pending from Mayfield et al. (2019)

3.4 References

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Wollin, K.-M., Damm, G., Foth, H., Freyberger, A., Gebel, T., Mangerich, A., Gundert-Remy, U., Partosch, F., Röhl, C., Schupp, T., and Hengstler, J. G. (2020). Critical evaluation of human health risks due to hydraulic fracturing in natural gas and petroleum production. Archives of Toxicology, 94(4), 967–1016. https://doi.org/10.1007/s00204-020-02758-7

4 WATER USE AND QUALITY

The literature describes the treatment and management of wastewaters as the central environmental concern regarding natural gas production. Especially in the eastern regions of the United States where—although water is abundant—significant natural gas production has been occurring. In the western part of the United States, persisting dry climates limit the use and availability of freshwater for natural gas production—~~, S~~specifically, freshwater availability for drilling and hydraulic fracturing.

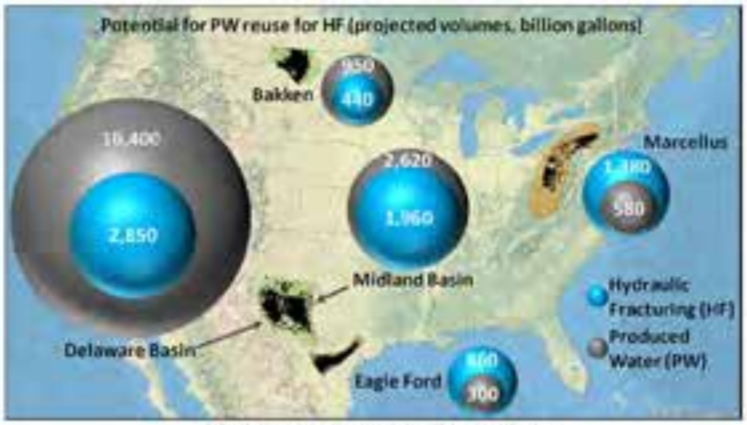
Gallegos et al. (2015) estimate that drilling and hydraulically fracturing a shale gas well can consume 2.6–9.7 MM gallons (gal) of water (Gallegos et al., 2015). From 2015 to 2014, unconventional shale gas in the United States used 187 billion (B) gal of water. From 2012 to 2014, the average use for hydraulic fracturing was 30.6 B gal annually. Additionally, Gallegos et al. (2015)'s integrated data from 6–10 years of operations suggest 212 B gal of combined flowback and produced water are produced from unconventional shale gas and oil formations. While the extensive growth in hydraulic fracturing revolution has increased water use for natural gas production across the United States, the water use and produced water intensity of these well stimulation activities~~hydraulic fracturing~~ is lower than the water use and produced water intensity of other energy extraction methods and represents only a small fraction of total industrial water use nationwide (Kondash and Vengosh, 2015). However, even the smallest local or seasonal water supply shortages can cause issues.

Water quality can also be impacted by natural gas production processes if water is inadequately managed or by the use of fracturing chemicals both on the surface—before injection and after flowback—and in produced water. Subsurface water quality impacts can result from the migration of fracturing fluids, formation waters, and CH_4 along well bores and through rock fracture networks. Management and disposal efforts increasingly include efforts to minimize water use through recycling and re-use of fracturing fluids, in addition to treatment and disposal of wastewater through deep underground injection.

The shale boom has made energy more available and affordable globally, but has also contributed to environmental concerns surrounding the use of water. Scanlon et al. (2020) analyze the water-related sustainability of energy extraction. They focus on meeting the rapidly rising water demand for hydraulic fracturing and managing growing volumes of water co-produced with oil and gas. They also analyze historical (2009–2017) volumes of water in ~73,000 wells and projected future water volumes in major U.S. unconventional oil and gas plays. Their results show a marked increase in fracking water use, depleting groundwater resources in some semiarid regions (Scanlon et al., 2020).

Water issues related to both fracking water demand and produced water supplies may be partially mitigated through the reuse of produced water to frac [illegible] fracking of new wells. As shown in Exhibit 4-1, projected produced water volumes exceed fracking water demand in semiarid Bakken (2.1×), Permian Midland (1.3×), and Delaware (3.7×) oil plays, with the Delaware oil play accounting for ~50 percent of the projected U.S. oil production (Scanlon et al., 2020). Therefore, water issues could constrain future energy production, particularly in semiarid oil plays.

Exhibit 4-1. Map showing ratio between produced water and fracking water demand for major shale basins



Permission pending from Scanlon et al. (2020)

4.1 WATER USE FOR UNCONVENTIONAL NATURAL GAS PRODUCTION

Most of the water used for unconventional natural gas production is used for drilling for hydraulic fracturing. For example, of the total water used by the shale gas industry, hydraulic fracturing is estimated to account for about 89 percent, drilling about 10 percent, and infrastructure the remainder (<1 percent) (Hayes and Severin, 2012). Water is also the main component of the fluids used for hydraulic fracturing, making up approximately 99 percent of the total volume.

Reporting from Gallegos, et al. (2015) suggests hydraulic fracturing uses 2.6–9.7 MM gal of water per well drilled, while the American Petroleum Institute (API) (2023) indicates that the average hydraulically fractured well uses 4 MM gal of water. As water is a scarce resource, it is important to consider the potential environmental impacts of using water from different sources (e.g., ground water, surface water). If available surface water is used to support natural gas production, then the ecosystems that rely on this water could be harmed. Significant groundwater withdrawals can also permanently deplete aquifers.

The process of hydraulic fracturing uses large volumes of water mixed with chemicals and proppant (sand) to fracture low-permeability shale and tight oil rocks, allowing the extraction of hydrocarbons ~~to occur~~. Despite the higher water intensity (the amount of water used to produce a unit of energy; for example, liters per gigajoules) compared to drilling conventional vertical oil and gas wells, overall water withdrawals for hydraulic fracturing is negligible compared to other industrial water uses on a national level (Vengosh et al., 2014; Jackson et al., 2014; Kondash, Albright, and Vengosh, 2017; Kondash and Vengosh, 2015). On a local scale, however, water use for hydraulic fracturing can cause conflicts over water availability, especially in arid regions such as the western and southwestern United States, where water supplies are limited (Scanlon, Reedy, and Nicot, 2014; Scanlon et al. 2017; Nicot and Scanlon, 2012; Ikonnikov et al., 2017; Kondash, Lauer, and Vengosh, 2018).

Commented [HSAJ141]: Comment for FE HQ - While this source is older than 2014 it helps to build the context for this section. Please advise if another more recent source is available and we will update accordingly.

Commented [HH142R141]: Hello Amanda.

Thank you for your comment. Please see the references below. Also, please feel free to reference our FOA 2796 (especially in the background section) for updates on the WM program's vision and technical focus areas:

https://www.gwpc.org/wp-content/uploads/2023/05/State-Regulations-Report-2021-Published-May-2023-FINAL.pdf

https://www.gwpc.org/wp-content/uploads/2023/06/2023-Produced-Water-Report-Update-FINAL-REPORT.pdf

https://www.gwpc.org/wp-content/uploads/2021/09/2021_Produced_Water_Volumes.pdf

https://www.energy.gov/fecm/funding-notice-water-research-and-development-oil-and-gas-produced-water-and-coal-combustion

Commented [EK143]: HH: Note about induced seismicity, which has become one of the main reasons for regulatory "Sticks" that are driving technological innovation.

4.1.1 Water Consumption Impacts

Water use for hydraulic fracturing and wastewater production in major shale gas and oil producing regions increased between 2011 and 2016, with water use per well increasing by up to 770 percent—with flowback and produced water volumes generated within the first year of production increasing up to 550 percent. ~~The w~~Water-use intensity (that is, normalized to ~~the~~ energy production) increased in all U.S. shale basins, except the Marcellus shale basin, over this period (Kondash, Lauer, and Vengosh, 2018).

Water consumption per shale gas well can vary due to four conditions:

- *Geology*: maturity of the shale and formation depth, thickness, and lateral extent
- *Technology*: horizontal or vertical drilling, water recycling
- *Operations*: operator decisions, availability of nearby freshwater
- *Regulatory*: requirements for use and treatment of water

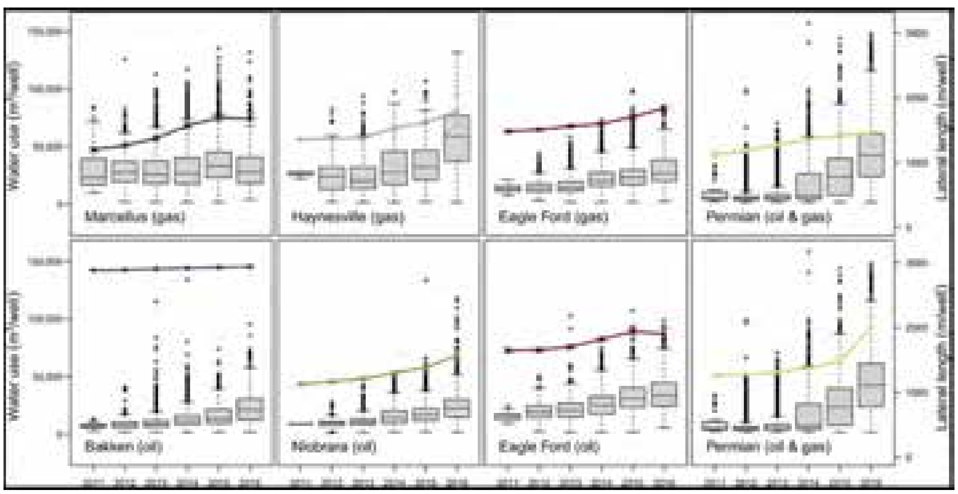
During 2009–2017, ~73,000 wells, or an aggregated total lateral length of ~440 × 10^6 ft (134,000 km), were drilled in the eight studied plays, equivalent to ~3× the Earth's circumference (40,000 km). Dieter et al. (2018) ~~find~~ found that to fracture the rock along that length, a total of ~480 B gal of water was used, equivalent to ~0.1 percent of the U.S. 2015 total water withdrawal, or almost two days of freshwater withdrawal (280 B gal/day). Exhibit 4-2 shows the water consumption for hydraulic fracturing, the amount of produced water used and oil and gas outputs from 9 major plays in the United States (Scanlon et al., 2020). The Eagle Ford play has used 173 B gal of combined hydraulic fracturing and produced water, at nearly a 1.83 ratio of freshwater~~:~~to produced water and the Marcellus has a freshwater~~:~~ to produced water ratio of 5.83. Other plays use more produced water than freshwater, like Bakken, Delaware, and Barnett, where the ratios of produced water to freshwater are 1.83, 2.21, and 2.11 respectively.

Exhibit 4-2. water use in nine shale plays in the U.S.

Play	Total Length (10^6 ft)	Median Well Length (ft)	Number of Wells	Hydraulic Fracturing Water (10^9 gal)	Produced Water (10^9 gal)	Oil (10^9 gal)	Gas (10^9 gal of oil equivalent)
Bakken	114	9,580	12,036	49	75	100	22
Eagle Ford	95	6,061	17,366	112	61	103	78
Midland	49	8,575	6,461	79	44	30	14
Delaware	36	5,272	7,070	51	113	40	26
Marcellus	51	7,139	9,651	70	12	3	214
Niobrara	21	7,438	3,842	21	5	14	11
Barnett	27	5,241	7,453	35	74	1	111
Haynesville	15	6,270	3,215	30	16	0.03	107
Fayetteville	21	6,386	4,717	24	-	-	55

Exhibit 4-3 from Kondash et al. (2018) indicates that, parallel to the increase in lateral lengths of the horizontal wells and hydrocarbon extraction yields through time, ~~the~~ water use has also increased. The relative increase in lateral length (4–60 percent) was, however, significantly lower than the increase in water use (14–770 percent). When water use per well is normalized to the length of lateral section of the horizontal well, in almost every case among oil producing regions, an increase in water use per length of the horizontal well is observed. This pattern is most evident in the Permian region, where water use increased from 4.4 cubic meter (m^3) per meter in 2011 to 29.3 m^3 per meter in 2016 for gas-producing wells, and from 3.9 m^3 per meter in 2011 to 21.1 m^3 per meter in oil-producing wells. In all cases, with the exception of the Marcellus shale play in 2016, the flowback and produced (FP) water generation ~~was~~ also increased~~ing~~ through time, with particularly higher rates after 2014.

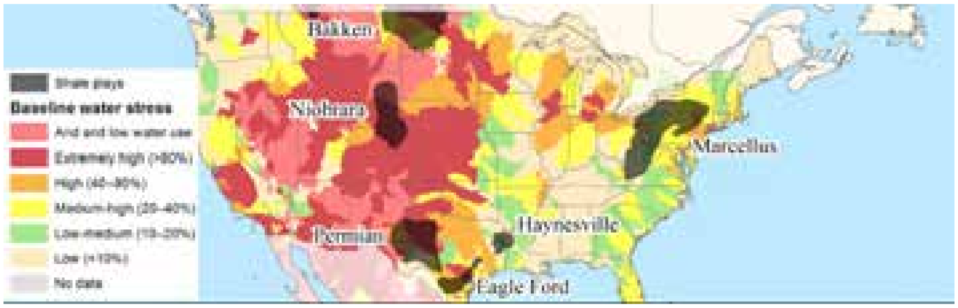
Exhibit 4-3. Water usage and lateral length by shale play



Used with permission from Kondash et al. (2018)

Kondash et al. (2018) also illustrate water conditions where the major plays across the United States are located, see Exhibit 4-4. The Bakken, Niobara, Permian and Eagle Ford plays are all located in arid to extremely dry climates where drought conditions have persisted for many years.

Exhibit 4-4. Baseline water stress and location of shale plays



Permission pending from Kondash et al. (2018)

4.1.2 Water Quality

Concerns have been raised about potential public health effects that may arise if hydraulic fracturing-related chemicals were to impact drinking water supplies. The chronic oral toxicity values—specifically, chronic oral reference values (RfVs) for noncancer effects, and oral slope factors (OSFs) for cancer are available for the list of 1,173 chemicals EPA identified as "associated with hydraulic fracturing." These include 1,076 chemicals used in hydraulic fracturing fluids and 134 chemicals detected in the flowback or produced waters from hydraulically fractured wells.

EPA compiled RfVs and OSFs for these chemicals using six different governmental and intergovernmental data sources. Ninety (8 percent) of the 1,076 chemicals used in hydraulic fracturing fluids and 83 (62 percent) of the 134 chemicals found in flowback/produced water had a chronic oral RfV or OSF reported in at least one or more of the six data sources used. Thirty-six of the chemicals used in hydraulic fracturing fluids have been measured in at least 10 percent of the hydraulically fracted wells drilled nationwide (identified from EPA's analysis of the FracFocus Chemical Disclosure Registry 1.0). Eight of these 36 chemicals (22 percent) had an available chronic oral RfV. The lack of chronic oral RfVs and OSFs for the majority of these chemicals highlights the significant knowledge gap that exists to assess the potential human health hazards associated with hydraulic fracturing (Yost et al., 2016).

Ecological risks to surface waters are present throughout the well life cycle and may manifest themselves differently locally compared to regionally. These risks can also vary temporally, as development activity like surface water withdrawal may only result in a single, brief impact, while the network of roads required for accessing ~~the~~ well pads could increase erosion and sediment runoff for years. Previous work identified the primary risks to surface water quality as sediment runoff from devegetation, leakage and spillage of chemicals into surface waters, unsustainable water withdrawal, landscape fragmentation, and insufficient treatment of oil and gas wastewater prior to discharge (Krupnick, Gordon, and Olmstead, 2013; Slonecker et al., 2012; Drohan et al., 2012; Kiviat, 2013). Unfortunately, few sites exist where baseline environmental monitoring occurred prior to hydraulic fracturing operations commencing (McBroom, Thomas, and Zhang, 2012). This greatly complicates efforts to precisely quantify impacts of hydraulic fracturing, particularly if these operations are occurring in watersheds with preexisting anthropogenic influence and a host of existing ecological stressors (Mauter et al., 2014).

The surface water risks and impacts associated with unconventional resource development ~~will~~ vary significantly by region (Clements, Hickey, Kidd, 2012). To date, those in the Marcellus region have been examined most extensively. This scrutiny has been motivated by the nexus of regionally-specific risk drivers, such as high gradient terrains that could lead to increased erosion, an abundance of small streams, highly variable in-stream flow rates, and the high salinity of produced water in the Marcellus. Moreover, during the early development of the Marcellus shale in ~~PA~~Pennsylvania, the state permitted the disposal of hydraulic fracturing brines in municipal wastewater treatment plants. To reduce the human and environmental impacts associated with this practice, energy and production companies have adopted a moratorium on the disposal of produced water in wastewater treatment plants in ~~PA~~ the state (Wilson and Van Briesen, 2012; Wilson, Wang, and Van Briesen, 2013; Warner et al., 2013; Wilson and Van Briesen, 2013; Renner, 2009).

In the Marcellus and Fayetteville plays, more than 80 percent of the active gas wells are located within 300 meters of drainage areas and recent studies have reported a positive correlation between total suspended solids and the density of upstream gas wells in both the Marcellus and Fayettville.

4.1.3 General Guidelines for Leading Regulatory Practices on Water Sourcing

Increasing demand for water for drilling and hydraulic fracturing in shale gas plays has driven operators to seek supplemental sources of water, and alternatives to local freshwater supplies. Potential alternatives include industrial wastewater, water treatment plant outflows, abandoned mine waters, saline groundwater, and reuse of produced waters.

Ceres (Freyman, 2014) developed a set of guidelines based on gathering the experiences, best practices, and issues throughout the U.S. shale industry. The following is a list developed by Ceres that describes the leading best practices for water sourcing:

- Catalogue the consumptive water use from hydraulic fracturing operations, including sources of water used and the amounts recycled.
- Require information on how operators are planning to manage wastewater streams including final disposal of water.
- Create integrated management structures for joint oversight of ground and surface water (as some are now proposing in British Columbia).
- Realize that higher disclosure requirements alone will not solve water sourcing impacts and risks and must be accompanied by proactive water management plans that include monitoring and enforcement components.
- Ensure that water-sourcing oversight is independent from the department granting oil and gas permits to minimize conflicting mandates and objectives.

Commented [RH144]: It was the State of PA that asked companies to stop doing this, so I would rephrase. According to PSU, "PaDEP asked gas drilling operators to voluntarily stop using these plants for Marcellus wastewater disposal by May 2011 because of mounting water quality concerns downstream of municipal wastewater discharge points." https://extension.psu.edu/water-journey-through-the-shale-gas-processes

Commented [LBD145]: In places like this where literature cited is of this vintage, it might be helpful to add something saying that these are the most recent studies available. [See global comment at beginning of document.]

Commented [LBD146]: Suggest adding a citation or some reference - the reader has just been provided information from 10+ year old sources, so "recent" could seem ambiguous; if this point is based on more recent information, suggest being as specific as possible about that.

Commented [EK147]: HH: Similar to previous comments—would recommend referencing the GWPC PW handbook, which was recently published. Updated guidelines include managing induced seismicity, CM recovery, and identifying safe beneficial reuse opportunities.

- Create systems of incentives and/or mandate requirements to encourage recycling and non-freshwater use.
- Implement measures to prevent invasive species transfers.
- Provide more resources to map and monitor groundwater resources, including remote aquifers and brackish water resources, across North America.
- Reduce reliance on aquifer exemptions and create incentives to minimize use of deep well injection sites.

4.2 REGULATIONS

Although EPA is generally responsible for water quality by regulating underground injection, hydraulic fracturing is exempt from federal regulation under the SDWA (except when diesel fuel is included in the fluid or there is an imminent and substantial danger to the health of persons). As a result, the responsibility to protect drinking water from hydraulic fracturing activity falls primarily on the states (Zirogiannis et al., 2016).

Rapidly growing demand for water for hydraulic fracturing has challenged water resource managers in many regions. Many state and regional water plans have quickly become outdated as demand for water for shale oil and gas development increases and expands into new regions (Collier, 2011).

States ~~or provinces~~ have the primary responsibility for permitting oil and gas development and related water sourcing, but there is currently significant disparity in their approaches to regulating shale water requirements and associated impacts. A recent study by Resources for the Future (RFF) looked at regulations relevant to shale gas energy development and found markedly different water withdrawal policies across 30 of the states they surveyed, including those with major shale energy development (Exhibit 4-5, states with major shale energy development are outlined in yellow). The study found that for most of the 26 states with any water withdrawal permitting requirements, only half require permits for all withdrawals. Several states do not require permits at all, but only disclosure of water use over a certain threshold, as represented by the light purple states (Freyman, 2014).

In addition, some states ~~and provinces~~ exempt the oil and gas operators industry from permitting requirements for water withdrawals, including the following:

- Kentucky, which exempts the industry from both surface and groundwater reporting
- Texas, which requires permits for surface water withdrawals, but generally not for groundwater

Commented [HH148]: The Groundwater Protection Council recently published a report on the state of produced water as well as state regulations.

Please reference the reports to ensure changes, especially state regulations, are represented:

https://www.gwpc.org/wp-content/uploads/2023/05/State-Regulations-Report-2021-Published-May-2023-FINAL.pdf

https://www.gwpc.org/wp-content/uploads/2023/06/2023-Produced-Water-Report-Update-FINAL-REPORT.pdf

https://www.gwpc.org/wp-content/uploads/2021/09/2021_Produced_Water_Volumes.pdf

Commented [TC149]: Please remove this section.

Commented [LBD150]: This verb tense (present perfect) doesn't match well with a source that is 12 years old – realizing that some editing is ongoing, but just pointing this out.

Exhibit 4-5. Water withdrawal regulations by state

Used with permission from Richardson et al. (2013)

In many cases, states where hydraulic fracturing is taking place have had to set their own regulations. The following is a list of examples of state-based water regulations related to hydraulic fracturing. This list is not exhaustive.

4.2.1 Pennsylvania

Pennsylvania is leading the way in requiring strong disclosure of freshwater and recycled water use during hydraulic fracturing. Within 30 days after completion of a well, the operator must submit a completion report to the Pennsylvania Department of Environmental Protection (PADEP). That report must include a stimulation record, which provides technical details associated with hydraulic fracturing, and list water resources that were used under an approved water management plan, including volume of water used from each source (25 Pa. Code § 78.122(b)(6); 25 Pa. Code § 78.122(b)(6)(vi)). Operators must also disclose the volume of recycled water used during well drilling (25 Pa. Code § 78.122(b)(6)(vii)). The PADEP then reviews individual plans and approves them, provided that water withdrawals:

- Do not adversely affect the quantity or quality of water available to other users of the same water sources.
- Protect and maintain the designated and existing uses of water sources.
- Do not cause adverse impact to water quality in the watershed considered as a whole.
- Are mitigated through a reuse plan for fluids that will be used to hydraulically fracture wells (58 Pa. Cons. Stat § 3211(m)(2)).

Other PA water regulations include the following:

- § 78a.15: If the proposed limit of disturbance of the well site is within 100 ft measured horizontally from any watercourse or any high quality or exceptional value body of water or any wetland 1 acre or greater in size, the applicant shall demonstrate that the well site location will protect those watercourses or bodies of water.
- § 78a.51. Protection of water supplies
    - A well operator who affects a public or private water supply by pollution or diminution shall restore or replace the affected supply with an alternate source of water adequate in quantity and quality for the purposes served by the supply as determined by the Department.
    - A landowner, water purveyor or affected person suffering from pollution or diminution of a water supply ~~as a result of~~ due to oil and gas operations may ~~to~~ notify the Department and request that an investigation be conducted. Notice shall be made to the appropriate Department regional office or by calling the Department's Statewide toll-free number at (800) 541-2050. The notice and request must include the following:
- Require operators to demonstrate how they will prevent damage to aquatic life during water withdrawals.[8]

Commented [EK151]: NETL Team - If we don't have the information / text to complete this sentence, I suggest we strike it altogether.

4.2.2 Colorado

The Air Pollution Control Division issued revised versions of Operating and Maintenance Plan Templates for Produced Water Storage Tanks.

In January 2013, the Colorado Oil and Gas Conservation Commission (COGCC) approved the most rigorous statewide mandatory groundwater sampling and monitoring rules in the United States. The purpose of Rule 609, "is to gather baseline water quality data prior to oil and gas development occurring in a particular area, and to gather additional data after drilling and completion operations" (COGCC, 2020).

Wells are constructed with multiple layers of steel casing and cement; COGCC rules require the following specifications for each well:

- In the water-bearing and hydrocarbon zones, the casing is cemented into place, and cement fills the void space between each layer of casing.
- At least two layers of steel casing and cement are in place from the ground surface to the lowest point of the freshwater aquifer.
- In the hydrocarbon formation, several thousand feet below the aquifer in most cases, there is at least one layer of steel and cement, and the hydrocarbons move through the inner-most casing to the surface.

[8] See section C.6 titled "Withdrawal Impacts Analysis," in the PADEP Water Management Plan For Unconventional Gas Well Development Example Format (2013).

Colorado requires disinfection of water suction hoses when water withdrawals occur in cutthroat trout habitats to avoid transfer of invasive or harmful species (Colo. Code Regs. § 404-1:1204, Westlaw 2012.).

4.2.3 Texas

The RRC (the agency that regulates the state's oil and gas industry) recently amended its rules to make it easier to recycle wastewater streams from hydraulic fracturing operations. Operators no longer need permits to recycle water and can even accept water from other areas or companies, as long as the recycling takes place on land leased by the operator so that oversight can be maintained. This new rule also allows operators to turn around and sell the water to other operators (Osborne, 2013).

Commented [EK152]: May want to state the actual year rather than 'recently' - especially if this reference is about a regulatory action that's no longer recent in 2023.

4.2.4 Ohio

Ohio's freshwater and recycled water use rules require operators to identify each proposed source of groundwater and surface water that will be used (Ohio Rev. Code §1509.06(A)(8)(a).). Ohio does not, however, require post-drilling disclosure of actual volumes of freshwater and recycled water used.

4.3 Current Research and Development and Analysis

NETL is performing advanced remediation technology research to better manage effluent water from energy production. The Water ~~Energy Effluent~~ Management Program aims to ensure that American water is affordable, reliable, sustainable, and resilient for energy use, and to reduce the environmental impact of freshwater consumption for energy production related to oil and gas operations (and coal combustion) as well as to reduce the volume of produced water disposal during oil and gas activities by:

- Improving treatment methods for produced water constituents that are ~~both~~ hard ~~and~~ costly ~~and energy intensive~~ to treat.
- Increasing the beneficial use possibilities for treated produced water outside of the oil and gas industry.
- Reducing environmental impacts related to produced water such as freshwater consumption in water scarce regions and induced seismicity.
- Characterizing produced water and energy effluent waters to identify potential resources such as critical minerals that could be harvested for uses within other industries.

To support this vision, the program aspires to reduce the environmental impact of freshwater consumption for energy production related to oil and gas operations and coal combustion as well as to reduce the volume of produced water disposal during oil and gas activities. The research areas include the following:

Commented [EK153]: HH: This is one of the few times we mention coal in this section–should we mention it throughout the section or should we remove reference to coal altogether?

- Treatment technologies – developing effective and cost-effective technologies and treatment trains to treat produced water

- Beneficial use technologies – increasing the likelihood that treated produced water can be utilized in other industries besides oil and gas
- Resource characterization – characterization of produced water constituents for potential harvesting for other industrial uses

A goal of the program is to engineer water composition to improve imbibition into the formation matrix with ionic modification, surfactants, and nanoparticles, which can change the wettability of carbonate rocks toward more water-wet conditions under which water can imbibe into the matrix and displace oil into the fractures. The modified water composition will be injected to improve oil recovery from the carbonate matrix in fractured reservoirs. The result can increase production from the well with no increase in the amount of water, chemicals, proppants, and energy required. This translates to minimized air emissions and other environmental impacts associated with production of a unit volume of oil and gas.

Currently, Water Management Program has existing projects:

- Develop effective treatment technologies to treat produced water via energy- and cost-efficient approaches for use within the oil and gas industry (2 projects)
- Develop advanced or novel membrane specific technologies for treatment of produced water (1 project)
- Developing methods characteriz extract rare earth elements or critical minerals (project)

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Commented [EK154]: HH: Would it be possible to provide the names of the projects? We have three additional ones in a university partnership effort, as well as initiatives in the digital space—just to ensure I don't double count.

Commented [ST155R154]: NETL: we need to ensure consistency in the depth and breadth of R&D sections across the chapters. Lets discuss.

Commented [EK156]: HH: Our program pivoted from this some time ago and we are no longer pursuing research in this area.

Commented [EK157R156]: HH: Please reference language about the new program from the NETL article (page 2). Text also copied below:

The Department of Energy (DOE) Office of Fossil Energy and Carbon Management (FECM) is celebrating the integration of the produced water (PW) management research and development (R&D) activities (originally housed within NETL Oil & Gas upstream research) with the Water Management for Power Systems program (operated under NETL's Crosscutting Research Program). These joined programs will be based in the Advanced Remediation Technologies Division (ART). The water-related R&D within FECM will be executed by ART-Water Management (ART-WM), representing one of the first combined programs of its type within DOE.

ART-WM's mission is to deliver societal benefits

Commented [EK158R156]: HH: This does not include the 7-8 FOA awards which will be announced in the coming weeks - yes?

Commented [EK159R156]: @Hadjeres, Hichem - I'm doing my best to integrate your excellent peer review feedback into this Sharepoint version of the Addendum. That said, I'm not exactly sure what you need with this comment RE: the 7-8 FOA

Commented [HH160R156]: @Easley, Kevin we are expecting another 7-8 projects to be added to our portfolio, which will cover new areas (e.g. CM recovery and extraction). The awards are expected to be made in a few weeks. The

Commented [EK161R156]: OK, thanks for the clarification, Hichem. I'll bring this up tomorrow when I meet with @Sweeney, Amy and @Curry, Thomas.

Commented [HH162R156]: @Easley, Kevin Thanks, Kevin!

Commented [HH163]: Please feel free to reword—basically talking about analysis and modeling of produced water samples and the work we do through PARETO to optimize PW management

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5 INDUCED SEISMICITY

Induced seismicity is ground motion (earthquakes) caused by human activities. Earthquakes have been detected in association with both oil and natural gas production, underground injection of wastewaters (i.e., wastewater disposal), and hydraulic fracturing (Rubinstein and Mahani, 2015). Each of these processes involves injecting large volumes of foreign fluids at various pressures into underground formations.[1] Earthquakes from induced seismicity have happened in multiple countries, including ~~in~~ the United States (Shultz et al., 2020).

5.1 IMPACTS FROM INDUCED SEISMICITY AND ENERGY TECHNOLOGIES

The term seismic activity is generally used to describe vibrations of mechanical energy that pass through the earth, much like sound waves vibrate through the atmosphere. The seismic activity of a region is defined by the frequency, kind, and magnitude of earthquakes experienced in the region during a given period. The National Earthquake Information Center (NEIC) is the entity responsible for determining, as rapidly and as accurately as possible, the location and size of all significant earthquakes that occur worldwide. At present, the NEIC locates and publishes detailed data on the 30,000 "most significant" earthquakes that occur in each year (USGS, 2023).

While millions of earthquakes occur each year, not all are felt at the surface. Earthquakes with magnitudes of 2.0 or less generally cannot be felt at the surface by people, while earthquakes with magnitudes greater than 3.0 tend to produce noticeable shaking. Earthquakes with magnitudes greater than 5.0 are felt at the surface and have the potential to cause structural damage to buildings and property. Most earthquakes that do occur are in response to natural, yet sudden slips and shifts of large masses of rock along geologic faults.

The seismicity rate in the central and eastern United States increased 40-fold within the past decade, predominantly as a result of human activities (Ellsworth, 2013; van der Baan and Calixto, 2017). This recent increase in seismicity rate in the central and eastern United States has largely been attributed to large-volume wastewater disposal wells injecting fluids into deep sedimentary formations (e.g., Keranen et al., 2014; Rubinstein and Mahani, 2015). Other human activities, including hydraulic fracturing (Skoumal, Brudzinski, and Currie, 2015) and carbon sequestration (e.g., Kaven et al., 2015), have induced seismicity to a lesser extent in the central and eastern United States (Skoumal et al., 2020).

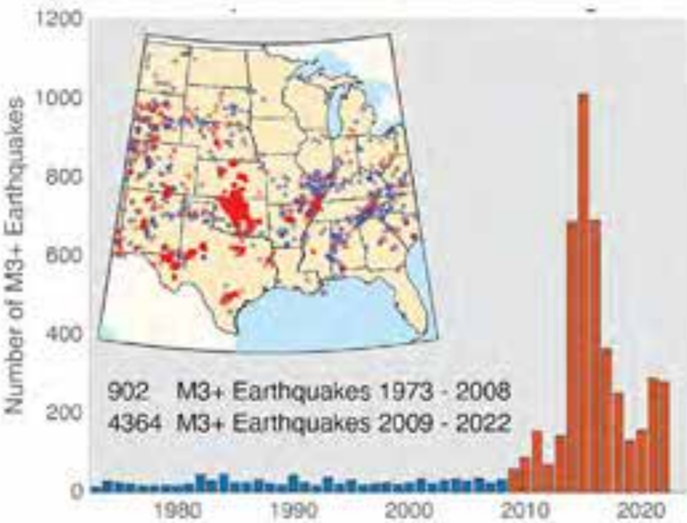
Commented [LBD164]: Suggest update phrasing to more precise years as this reads as 2013-2023 to a current reader.

Exhibit 5-1 presents the annual number of earthquakes (with a magnitude of 3.0 or larger) occurring in central and eastern areas of the United States for 1973–2022. Many of these earthquakes have taken place in areas where hydraulic fracturing has been and is actively occurring (e.g., Oklahoma) (USGS, 2022). Between 1973 and 2008, approximately 25 earthquakes of magnitude three or greater occurred on average annually. Since 2009, at least 58 earthquakes of this same size (magnitude of 3.0 or larger) have occurred annually, and at

[1] Hydraulic fracturing involves injecting large volumes of fluids into the ground to release trapped oil and natural gas. Wastewater from oil and gas production, including shale gas production, is typically disposed of by being injected at relatively low pressures into extensive formations that are specifically targeted for their porosities and permeabilities to accept large volumes of fluid.

least 100 earthquakes of this same size have occurred annually since 2013. The annual number of earthquakes (with a magnitude of 3.0 or larger) peaked in 2015 when 1,010 magnitude 3+ earthquakes were recorded. Given their magnitude, most of these earthquakes are large enough to have been felt by people, yet ~~small~~ not large enough to cause significant damage (USGS, 2022).

Exhibit 5-1. Earthquakes in the Central and Eastern U.S. 1973–2022



The following are examples of induced seismic events in the United States that have occurred in basins where unconventional natural gas production via hydraulic fracturing has occurred.

5.1.1 Utica and Marcellus Shales in the Appalachian Basin

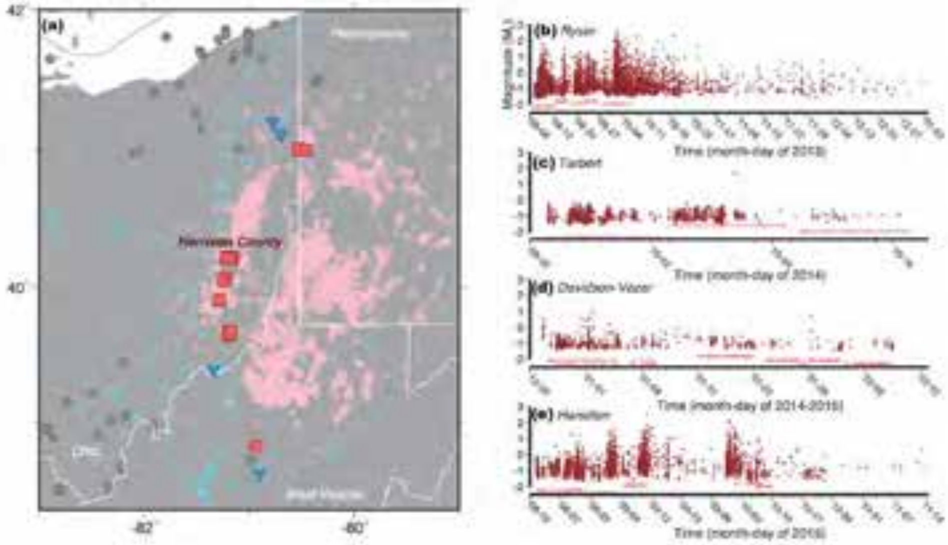
The Appalachian Basin is currently the largest natural gas producing area in the United States. The basin produced over 18 Mcf of natural gas a day (500 m^3/day) in 2019 (EIA, 2019a). The Marcellus and Point Pleasant Utica shale plays are both located in the Appalachian Basin and extend from New York to Kentucky. They each cover prospective areas of 190,000 and 220,000 square kilometers (km^2), with proven reserves of 135 and 24 Tcf of natural gas, and 345 and 210 MM barrels of oil, respectively (EIA, 2019b). Earthquakes detected in the basin during 2013–2015 are presented in Exhibit 5-2.

Commented [EK165]: Is the 2015 induced seismicity information presented here sufficiently 'recent' for the purposes of this Addendum? Is more recent data available from USGS as the graph at the top of the page and supporting text narrative refers to a 2022 data source.

The map on the left provides the location sequences of cataloged (magnitude > 2.0) seismic events in Ohio and neighboring states for 2010–2017. Blue triangles show earthquake sequences induced by wastewater disposal; red squares show earthquake sequences induced by hydraulic fracturing; and pink squares and blue triangles depict the horizontal and wastewater disposal wells that remain in the area. Grey circles represent earthquakes assumed to be occurring from natural causes. The four graphs on the right provide the temporal

distribution of hydraulic fracturing induced seismic events for four wells in Harrison County, Ohio (Schultz, 2020).

Exhibit 5-2. Location and timing of induced and natural seismic events in the Appalachian Basin



Permission pending from Schultz (2020)

5.1.2 Anadarko and Arkoma Basins of Oklahoma

Dramatic increases in seismic activity have been reported for areas in both central and northern Oklahoma, where the Anadarko and Arkoma Basins are located. Historically, an average of one to two ML[m] ≥ 3.0 earthquakes occurred in Oklahoma annually. The number of ML ≥ 3.0 earthquakes occurring in the state, however, rose to over 900 in 2015.

While the seismicity rate began to decline in 2016 the yearly total seismic moment of Oklahoma remained high in response to three Mw[n] ≥ 5.0 earthquakes occurring during the year. Including the Pawnee earthquake, the largest earthquake (5.8 Mw) ever recorded for the state of Oklahoma. The seismicity rate increase has generally been attributed to the disposal of large volumes of produced water into the Arbuckle Group basin (Haffener, Chen, and Murray, 2018).

Exhibit 5-3 shows the location (left) and magnitude (right) of induced seismic events in Oklahoma between 2010 and 2020. In the map on the left seismic events from natural causes are represented by the blue circles, while induced seismic events are represented by the red (Skoumal et al., 2018) and orange circles (Shemeta, Brooks, and Lord, 2019). The graph on the

Commented [EK166]: NETL Team - 'moment' (as written) or events or some other term? If 'moment,' it's unclear what message / finding the sentence is trying to convey. Also, 'of' Oklahoma' (as written) or 'in' Oklahoma.

Commented [EK167]: NETL Team - this sentence appears to be incomplete. If it is meant to amplify the preceding sentence, I suggest it be reworded as it's confusing / unclear as written.

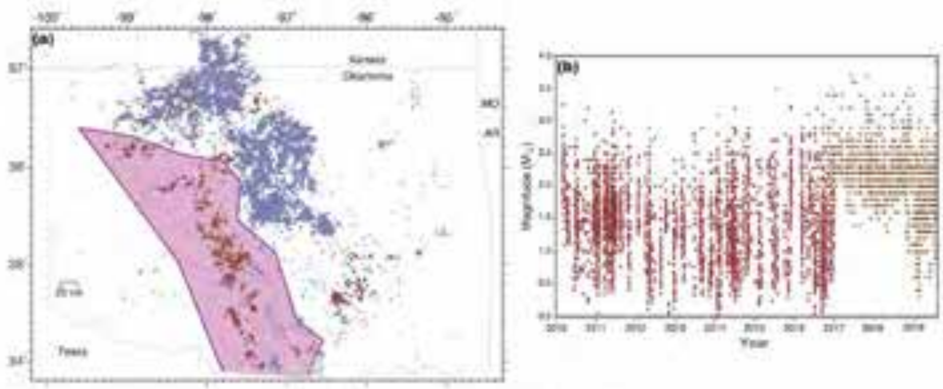
[m] ML refers to the magnitude on the Richter scale, where M stands for magnitude and L stands for local.

[n] Mw is known as the moment magnitude of an earthquake. For very large earthquakes, moment magnitude gives the most reliable estimate of earthquake size.

left shows the number and magnitude of the induced seismic events over time (Skoumal et al., 2018; Shemeta, Brooks, and Lord, 2019).

Commented [EK168]: NETL Team - did you mean to type the graphy on the right in Exhibit 5-3 as it's the one that has a 'time series' (2010 - 2019) along the horizontal axis.

Exhibit 5-3. Induced seismicity events in Oklahoma



Permission pending from Schultz (2020)

5.1.3 Fayetteville Formation in the Arkoma Basin of Arkansas

Following the success of the Barnett Shale (Fort Worth Basin, Texas) the Fayetteville Formation in Arkansas became an early target for continued shale gas development in the United States. This unconventional play runs east to west across north central Arkansas, extending across nearly 150 km. By 2005, horizontal well completions in the middle to lower organic rich facies at depths typically 1–2 km were coming online and, by 2009, 0.5 Tcf of gas was being produced per year (Browning et al., 2014).

The Fayetteville Formation has a history of seismicity that dates back to before the region was developed for oil and natural gas extraction. In September 2010, a series of seismic events reaching magnitudes close to 5.0 Mw on the Richter Scale occurred along the Guy-Greenbrier Fault within the basin. Not long after, on February 28, 2011, a 4.7 Mw earthquake—the largest ever recorded—occurred within the basin. This led to concerns that even larger earthquakes could potentially occur in the area, which resulted in an emergency shutdown order for any injections being put in place by the Arkansas Oil and Gas Commission. Analysis of the seismicity, injection patterns, and pore pressure diffusion built a strong case for the activation of the Guy-Greenbrier Fault by wastewater disposal (Horton, 2012; Ogwari, Horton, and Ausbrook, 2016; Ogwari and Horton, 2016; Park et al., 2020). In the neighboring states of Oklahoma and Texas, wastewater disposal by injection is understood to be the primary driver of induced seismicity.

5.1.4 Eagle Ford Shale Play in the Western Gulf Basin of Texas

Texas has a long history of active oil and natural gas production, hydraulic fracturing, wastewater disposal, and general seismicity, ~~S~~some of which occurs within or near areas of

pervasive faulting (see Exhibit 5-4a) (Ewing, 1990; Frohlich et al., 2016). Advancements in horizontal drilling and hydraulic fracturing since 2008 have prompted the Eagle Ford shale play to focus on hydrocarbon production from the Upper Cretaceous Eagle Ford and Austin Chalk Formations (Frohlich and Brunt, 2013; Martin et al., 2011; Pearson, 2012; RRC, 2019).

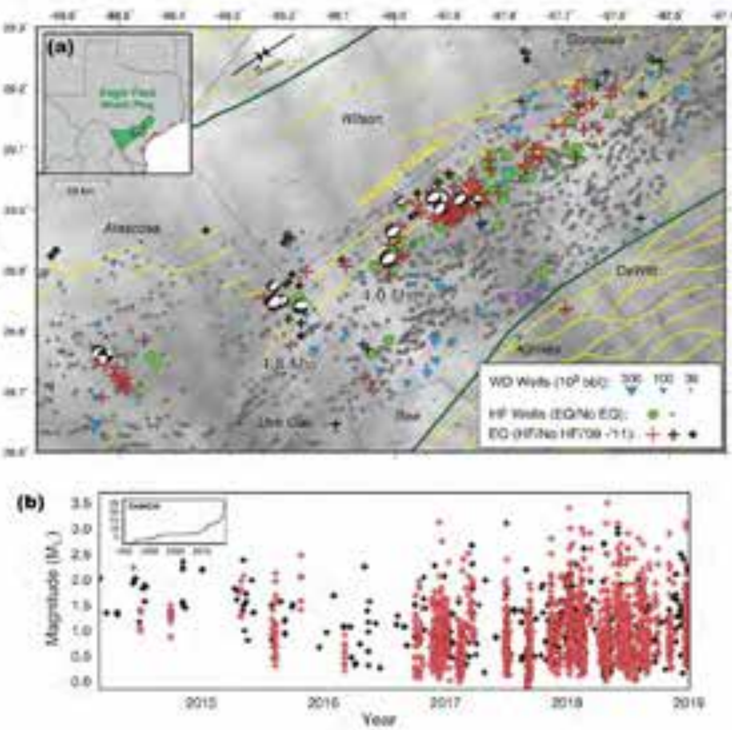
In 2018, the rate at which ML ≥ 3.0 earthquakes occurred in the Eagle Ford shale play was 33 times higher than background levels (3 earthquakes per 10 years during 1980–2010; see Exhibit 5-4b). Fasola et al. (2019) investigated seismicity that has occurred since 2014, in an effort to identify how hydraulic fracturing has contributed to seismicity within the play. Comparing both times and locations of hydraulic fracturing to a catalog of seismic activity, Fasola et al. (2019) suggest more than 85 percent of the seismicity that occurred was spatiotemporally correlated with hydraulic fracturing. More specifically, there were 94 ML ≥ 2.0 earthquakes correlated will 211 hydraulic fracturing well laterals.

Commented [EK169]: NETL Team - 'will' (as written) or 'with' - or perhaps something else?

Exhibit 5-4a provides a map from the Texas Seismological Network showcasing earthquakes (crosses) and focal mechanisms (beach balls) that have occurred since 2017. Hydraulic fracturing wells are indicated by black circles in Exhibit 5-4. Correlated earthquakes and hydraulic fracturing wells are displayed as red plus signs and green circles, respectively. Black diamonds show the earthquakes that occurred during 2009–2011 (Frohlich and Brunt, 2013). Purple square shows the seismic station (735B) used for template matching. Wastewater disposal wells are provided as teal triangles sized by median monthly volumes. Arrows show regional orientation (Lund Snee and Zoback, 2016). Faults (Ewing, 1990) are in yellow.

Exhibit 5-4b provides the magnitudes of the various earthquakes both correlated and not correlated with hydraulic fracturing that occurred annually after 2011 within the play (the black and red plus signs shown in Exhibit 5-4a). The inset shows the cumulative number of earthquakes (magnitude ≥ 3.0) occurring in the area, available from the United States Geological Survey (USGS) Comprehensive Catalog.

Exhibit 5-4. Locations and timings of Eagle Ford hydraulic fracturing induced event



Permission pending from Fasola et al. (2019)

5.2 Regulations to Address Induced Seismicity and On-Going Research and Development

State regulators have long been focused on identifying the precise location and magnitude of earthquakes and determining their cause. When earthquakes can be linked to wastewater injection, regulators operators to cease or limit either injection rates and/or water volumes in nearby wells (EPA UIC National Technical Workgroup, 2015). Many regulators also require that new injection wells avoid areas near known active faults. In Oklahoma, these techniques have effectively reduced the number of felt earthquakes.

Commented [EK170]: NETL Team - Changed 'If' to 'When' since the Addendum has already cited wastewater injection is one driver of induced seismicity.

Similar procedures have been applied to hydraulic fracturing operations in some states. That is, when earthquakes are detected, operations are either modified or suspended (AGI, 2017). Oklahoma, Texas, and Ohio have all taken steps to mitigate induced seismicity linked to hydraulic fracturing. In Oklahoma, regulators have instituted the following actions to address induced seismicity (Boak, 2017)

- Governor created the Coordinating Council on Seismicity (2014)

- Oklahoma Corporation Commission directives reduce injection (2015)
- Oklahoma Geological Survey position paper published (2015)
- Secretary of Energy fund $200,000 seismicity projects (2015)
- Governor's Water for 2060 Produced Water Working Group (2015)
- Research Partnership to Secure Energy for America funded stations that were added to the Oklahoma Geological Survey network (2016)
- Governor's Emergency Fund allocated $1,387,000 to bolster the emergency response capacity of the Oklahoma Corporation Commission, and Oklahoma Geological Survey (2016)
- ~~New~~ Created a tracking system for earthquakes and injection activities for the Oklahoma Corporation Commission to monitor and assess these events and operator practices (2016)

In Texas, the state's ~~Texas'~~ Center for Integrated Seismicity Research (TexNet) is charged with monitoring, locating, and cataloging seismicity across the state. Capable of detecting and locating earthquakes with magnitudes ≥ 2.0. TexNet's backbone network improves investigations of ongoing sequences of seismic activity by deploying temporary seismic monitoring stations and conducting site-specific assessments (Young et al., 2017). TexNet will continue to conduct fundamental and applied research to better understand both naturally and potentially induced seismic events that are occurring across the state of Texas, their associated risks, and potential strategies for communicating with stakeholders and responding to public concerns raised regarding seismicity. (Young et al., 2017)

~~Component~~Additional state requirements and activities associated with seismicity include the following (Young et al., 2017):

- Applicants are required to search the USGS seismic database for historical earthquakes within a circular area of 100 square miles around a proposed, new disposal well (~5.6-mile radius)
- Clarifying the Texas Railroad Commission's (RRC)'s authority to modify, suspend or terminate a disposal well permit, or modify operations if scientific data indicates a disposal well could be contributing to seismic activity
- Increased disclosure of reported volumes and pressures, at RRC's discretion
- RRC may require applicants to provide additional technical information to demonstrate disposal fluid confinement

Ohio has regulated seismic permits for injection wells for some time; obtaining a permit can require the following tests or evaluations of a proposed brine injection well be completed, in any combination that the chief deems necessary (Dade, 2017):

Commented [EK171]: NETL Team - to your knowledge, is this 2015 funding reference the most recent DOE / S-1 investment into induced seismicity projects?

Commented [LBD172]: Is any update available?

Commented [EK173]: NETL Team - It's unclear who the 'Applicants' are, what they are applying to, etc. Please provide additional details.

Commented [EK174R173]: Are we referring to operators in Texas applying for permits of one type or another RE: drilling, disposal, etc.? Please clarify.

Commented [LBD175]: Is any update available?

- Geological investigation of potential faulting within the immediate vicinity of the proposed injection well location, which may include seismic surveys or other methods determined by the chief to assist analysis.
- Permit conditions may include seismic monitoring, pressure fall-off tests, spinner tests, radioactive tracer, geophysical and electrical logs, and downhole pressure monitoring.

Restrictions may be placed on wells drilled near faults or areas known for seismic activity, in which seismic monitors must be installed for a specified period prior to completion operations (Dade, 2017). Related actions include:

- ML ≥ 1.5 – Direct communication starts between operator and division
- ML = 2.0–2.4 – Work with operator to propose or modify operation
- ML ≥ 2.5 – Temporary halt completions on lateral
- ML = 3.0+ – ompletion on pad suspended until an

The mitigation techniques employed by Ohio include the following:

- Direct communication with the operator is essential
- Discussion of seismic events and stages of the operation need to occur in real-time
- Spatial analysis and time correlation with completion data conducted during the operation

Mitigation techniques when induced seismicity occurs during hydraulic fracturing include the following:

- Change from zipper fracking to stack fracking
- At least 20% reduction in volume and/or pressure
- Skipping stages may be necessary, especially if seismic events indicate a lineament or fault structure near a lateral of the operation
- Switch to smaller sieve sizes for proppant, full effect still unsure

5.3 References

AGI. (2017). *State Responses to Induced Seismicity.* AGI.

Boak, J. (2017). *Patterns of Induced Seismicity in Central and Northwest Oklahoma*, [Online]. *Oklahoma Geological Survey*. Available at https://www.americangeosciences.org/sites/default/files/webinar/assets/AGI_InducedEQ_Webinar_Apr2017_Boak.pdf

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Commented [EK176]: NETL Team - the 'shorthand' in these bullets is confusing, poorly written, and as such I'm uncertain if my proposed text revisions are correctly adjusting the text to make it more understandable. Please feel free to expand upon / revise this section as needed.

Commented [EK177]: NETL Team - please flesh this out as this is very technical terminology many prospective users / readers of the Addendum may not readily recognize / understand.

Commented [EK178]: NETL Team - please add some text to describe why stages may need to be skipped due to seismic events indicating "a lineament or fault structure near a lateral of the operation."

Commented [EK179]: NETL Team - what is meant by / the consequences of this phrase: "full effect still unsure' when switching to smaller sieve sizes for proppant.

Dade, S. (2017). *OhioNET: State of Ohio's Response to Induced Seismicity,* [Online]. Ohio Department of Natural Resources: Division of Oil & Gas Resources Management. Available at https://www.americangeosciences.org/sites/default/files/webinar/assets/AGI_InducedEQ_Webinar_Apr2017_Dade.pdf

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6 LAND USE AND DEVELOPMENT

The growing land use footprint of energy development, termed "energy sprawl," ~~will~~ likely causes significant habitat loss and fragmentation with associated impacts to biodiversity and ecosystem services (McDonald et al., 2009). Land presents a critical yet often overlooked constraint to energy development, including the development of domestic natural gas. Natural gas is set to act as a transition fuel and dominant technology during the grid decarbonization process in the United States, making an understanding of its land use implications critical and necessary consideration (Dai et al. 2023).

Expanding energy development is now the primary source of anthropogenic land cover change in natural ecosystems in North America (Allred et al., 2015; Trainor, McDonald, and Fargione, 2016), including eastern deciduous forests, boreal forests, prairie grasslands, sagebrush-steppe, and deserts (Copeland, Pocewicz, Kiesecker, 2011; McClung and Moran, 2018; Appiah, Opio, Donnelly, 2019). Land use and development issues associated with natural gas production include local surface disturbance; cumulative landscape impacts; habitat fragmentation; and traffic, noise, and light. Vertical wells are typically spaced with 40 acres per well, the drill pads from which each horizontal well originates are typically spaced with 160 acres per well. If wells are drilled conventionally (i.e., vertically) a single square mile of surface area can support 16 pads with one well per pad. If wells are drilled horizontally then the same amount of surface area could ~~support~~ be used to develop 1 pad, from which 6–8 different wells could be drilled (NETL, 2009).

The Citizens Marcellus Shale Coalition (CMSC) (2011) explored two issues related to impacts of shale gas production on public lands and the other industries that rely on these lands. They also explored ~~the~~ impacts on private property rights. CMSC stated that shale gas development must consider the cumulative impacts on state parks and forests and on timber and tourism industries as part of responsible stewardship of public resources. Property rights and environmental degradation are a growing public concern, and eminent domain laws, drill spacing requirements, and grouping of leased lands could help protect these rights.

Commented [HSAJ180]: Comment for PE/HQ: In some cases the best source of information we had for land use impacts predated 2014. Please advise if you would like to see these removed.

Commented [EK181R180]: Amanda - I love that paragraph. Except for the '2011' reference in parentheses. Do we have to 'hang a lantern' there on how dated that reference is? If what was true then remains true today, I would prefer we remove the "(2011)" reference and continue along. Anyone else have strong feelings on this? @Curry, Thomas @Skone, Timothy @Lavoie, Brian D.

6.1 SURFACE DISTURBANCE AND LANDSCAPE IMPACTS

The infrastructure ~~to~~ needed to support the supply chain of electricity produced from natural gas involves production sites (production pads and their access roads), transportation facilities (e.g., gathering and transmission pipelines for natural gas), processing facilities, and power plants (end-use) (Dai et al., 2023). Such activities can disturb Earth's surface, the impacts of which can extend over large areas and result in habitat fragmentation that impacts both plant and animal species. Mitigation options include adoption of best-practices for site development and restoration, avoidance of sensitive areas, and minimization of impacts to disturbed areas.

Dai et al. (2023) used machine learning, remote sensing, and geographic information systems to obtain spatially explicit information on the land required to support natural gas production. Their analysis considered land use across five life cycle stages of natural gas produced for electricity production from wells (production stage), natural gas transportation via gathering pipelines (gathering stage), natural gas processing ~~plants~~ (processing stage), natural gas

Commented [EK182]: NETL Team - suggest removing 'plants' here as we're focused on the activity itself; if you want to footnote a point RE: land required for all of the processing plants involved in unconventional production here in the U.S., if necessary, that would be fine.

transportation via transmission pipelines (transmission stage), and through combustion in gas-fired power plants (use stage).

Commented [EK183]: NETL Team - 'the use through' was somewhat clunky so I switeched up the text.

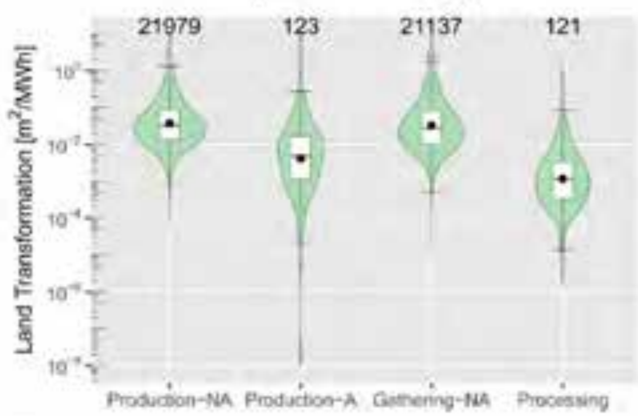
For the production stage, Dai et al. (2023) map land-use for 100,009 wells located at 75,915 different well pads. Among the 100,009 wells examined, 31,716 were co-located. In non-agricultural areas, results suggest vertical wells occupy ~4000 square meters (m^2) less land per site than horizontal-/directional-drilled wells. During the gathering stage in both agricultural and non-agricultural areas, sites with horizontal-/directional-drilled wells, on average require ~230 meters less pipeline in length than sites with vertical-drilled wells, whereas due to the requirement for larger width of right-of-way, the extent of land use is almost doubled for sites with horizontal-/directional-drilled wells. Results from Dai et al. (2023) are summarized in Exhibit 6-1.

Exhibit 6-1. Land use throughout the life cycle of gas-fired electricity

Stage			Unit	Average
Production	Agricultural	Directional	m^2 per site	9,346
		Vertical	m^2 per site	2,100
	Non-agricultural	Directional	m^2 per site	18,170
		Vertical	m^2 per site	14,090
Transportation by gathering	Length	Directional	m^2 per site	597
		Vertical	m^2 per site	818
	Area	Directional	m^2 per site	20,157
		Vertical	m^2 per site	10,128
Processing			m^2 per (MM cubic feet per day)	4,318

Exhibit 6-2 from this study illustrates the land transformation by stage, showing that production in non-agricultural areas utilizes more land than agricultural areas.

Exhibit 6-2. Land transformation in natural gas production



Note: NA = non-agricultural area, A = agricultural area

Used with permission from Dai et al. (2023)

Notably, technological advancements will play a significant role in decreasing the amount of land that will be transformed during the life cycle stages of production, gathering, and of natural gas (Dai et al., 2023).

Commented [LBD184]: Suggest a few words explaining how, or possibly delete this sentence.

6.2 HABITAT FRAGMENTATION

The construction and installation of the infrastructure necessary for development of natural gas development can lead to a habitat being converted from a large contiguous patch of similar environments to several smaller, isolated environments. Long-term effects of shale gas production on habitat disturbance will have to be evaluated as the development of these resources continues. Mitigation measures such as avoidance, best management practices, and prompt reclamation of the drilling site have been put forward as ways to best minimize the possible impacts that shale gas production may have on habitats. Habitat disruption can also result from a lack of surface water availability in response to withdrawals to support natural gas production and quality from erosion and chemical spills. The potential water use implications of natural gas are discussed in Chapter 4 – Water Use and Quality.

There are several impacts associated with the development of gas drilling sites and natural gas production that can disrupt the habitat of both plant and animal species. These impacts can arise from a variety of sources and at various points throughout the extraction and production process. Habitat fragmentation occurs when infrastructure must be installed, or land clearing must take place to allow access to a well location. Habitat fragmentation was given as one of the environmental risk pathways that were identified as a consensus priority risk pathway in a survey of 215 experts in government, industry, academia, and non-governmental organizations (RFF, 2013).

When contiguous core habitats are fragmented into smaller patches, many sensitive species are unable or unwilling to cross non-habitat regions to reach alternative habitat patches. While habitat loss can have an immediate impact on wildlife population, the ecological response to fragmentation is lagged, and affects different species at varying timescales (Makki et al., 2013).

A secondary impact of fragmentation is the creation of edges. Edges are generally defined as the 100 meters between core forest and non-forest habitat (PADEP, 2014; Kargbo, Wilhelm, and Campbell, 2010; Johnson et al., 2010). New edges affect the physical or biological conditions at the ecosystem boundary and within adjacent ecosystems (Fischer and Lindenmayer, 2007). Edge effects are believed to be detrimental by increasing predation, changing lighting and humidity, and increasing the presence of invasive species (Johnson et al., 2010).

Exhibit 6-3 provides a schematic depicting the habitat loss and fragmentation from natural gas production. Exhibit 6-3 progresses from infrastructure development that has quantifiable land impacts leading to temporally extended land changes, impacts which account for habitat loss and fragmentation.

Exhibit 6-3. General procedure for depicting land disturbance from natural gas extraction

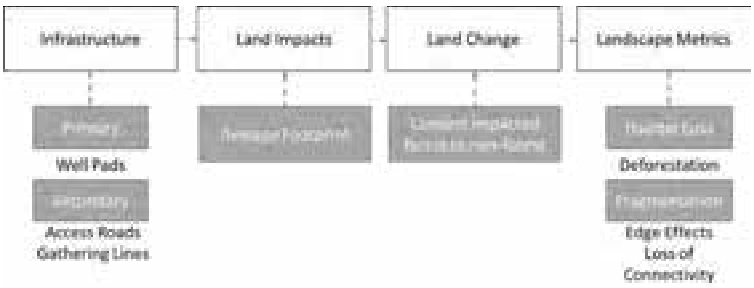
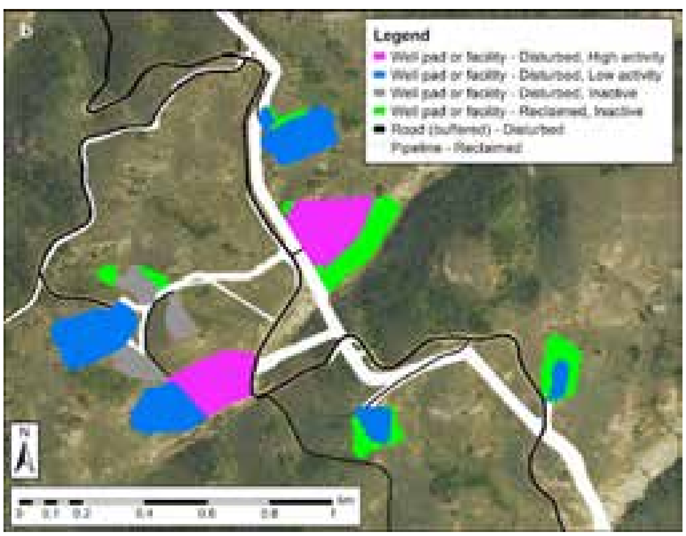


Exhibit 6-4 provides an example of energy infrastructure features digitized from 2013 National Agricultural Inventory Program satellite imagery overlaid with well locations reported in COGCC data. Each mapped feature (or portion thereof) was classified by type (well pad, facility, road, or pipeline) and by surface type (disturbed or reclaimed), and well pads and facilities (or portions thereof) were assigned an activity status (high, low, or inactive) (Walker et al., 2020).

Exhibit 6-4. Footprint of a well pad and surrounding infrastructure



Used with permission from Walker et al. (2020)

Each region where natural gas extraction takes place has unique species and habitat therein~~that inhabit the particular regions~~. Within those species, some are more greatly affected than others, whether it be core habitat fragmentation or~~f~~ edging.

6.3 Noise, Light, and Traffic

Natural gas development processes are associated with both noise and light pollution, which can contribute to stress among those living in nearby communities (Down, Armes, Jackson, 2013; Korfmacher et al., 2013; Peduzzi et al., 2013; Witter et al., 2008a; Witter et al., 2008b). Construction, vehicles, drilling, compressors, flaring, and other processing equipment and facilities can all pollute through excessive noise and continuous illumination (Cleary, 2012).

6.3.1 Noise Pollution

~~The~~ A health impact assessment in Colorado identified noise pollution as an area of concern and noted that it occurs during drilling and completion operations, flaring, and because of ~~as a result of~~ vehicular traffic (Witter et al., 2013). Workers can be exposed to noise through many sources on site, including diesel engines, drilling, generators, mechanical brakes, ~~operation of~~ heavy equipment operations, and radiator fans (Witter et al., 2014); therefore, hearing impairment is a noise-related health concern for workers on site.

A biomonitoring study from Texas found residents reporting concerns about odors and noise apparently related to shale gas well and compressor station operations, although this was a separate, independent component from the biomonitoring portion designed ~~in order~~ to address residents' concerns (Texas Department of State Health Services, 2010). While the authors noted that it was difficult to determine if the levels were above acceptable limits that may be harmful to human health, and that noise may affect quality of life, this is speculative because noise levels were not measured to establish decibels of noise in the study area.

Noise standards for a single well pad may be met; however, the cumulative effects of multiple operations in one area might exceed these established decibel levels. In terms of setback distances, some noise regulations distinguish between maximum decibels for day and night, while others distinguish between maximum decibels for certain phases of the operation such as drilling, fracturing, and production; however, there is often variability and, in some areas, it is suggested that distances are set as monitoring points, not necessarily points indicative of being protective of health (Fry, 2013).

6.3.2 Light Pollution

Light pollution has significant implications for the environment and public health, and its effects have become more pronounced over time due to the increasing extent and radiance of artificially ~~-~~lit areas (Kyba, 2017). Substantial economic values have been attached to affected outcomes, such as biodiversity, recreation, and public health. With respect to human health, artificial lights at night are associated with sleep deprivation and mental health (Patel, 2019; Xiao, 2020); sleep deprivation, in turn, has been shown to reduce cognition and labor market productivity, as well as elevate mortality risks associated with dementia, heart attacks, and vehicle accidents (Hafner et al., 2017; Paksarian et al., 2020; Ma et al., 2020; Jin and Ziebarth, 2020; Prats-Uribe, Tobías, and Prieto-Alhambra, 2018.). A study in Australia quantified the financial and non-financial costs of inadequate sleep in 2016–2017 to be $45 B (Hillman et al., 2018) and another study estimates that $680 B is lost due to sleep deprivation across five

Organisation for Economic Co-operation and Development countries (Hafner et al., 2017; Boslett, 2021).

Light pollution also has significant consequences for wildlife populations. It affects nighttime behavior and habits of terrestrial (Bennie et al., 2015) and marine (Davies et al., 2014) wildlife populations, particularly for species that use sun or moon light for guidance. It disrupts natural sleep and reproductive cycles, geographical orientation, and predator-prey relationships (Longcore and Rich, 2004). Other effects of light pollution include changes in bird singing behavior (Miller, 2006), estrus patterns in nocturnal primates (LeTallec, Théry, and Perret, 2015), insect pollination (MacGregor, 2015), and fish biological rhythms (Brüning et al., 2015). These impacts have led to ecosystem-wide changes in biodiversity and growing disparities between entire taxonomic groups (Davies et al., 2013).

The impacts of light pollution also extend to human health and well-being. Artificial light disrupts melatonin secretion and circadian rhythm (Haim and Zubidat, 2015) with corresponding changes on mood regulation, depression, and sleeping disorders (Cho et al., 2016). Light pollution-driven changes in circadian rhythms may also have contributed to recent growth in obesity and metabolic dysfunction (Fonken et al., 2010). Growing laboratory and epidemiological evidence also support the long-hypothesized relationship between nighttime light exposure and cancer rates (Kerenyi, Pandula, and Feuer, 1990; Kloog, et al., 2010; Schwimmer et al. 2014; Jones, Pejchar, and Kiesecker, 2015).

While there is some work speculating that light pollution associated with shale development induces psychosocial stress (Fisher et al., 2017), sleep and mental health issues (Casey et al., 2018), and local ecosystems (Kiviat, 2013), the literature directly connecting the recent resource boom to light pollution is extremely limited. Importantly, no work has documented the causal impact of U.S. shale development on light pollution.

6.3.3 Traffic Pollution

Traffic may increase in any given area of unconventional natural gas development, but the magnitude of this increase has not been studied in depth. The phases of development that require the most traffic load involve well pad construction, drilling and well completion, and pipeline construction (Witter et al., 2014). It appears that changes in traffic patterns will be dependent upon the area and the individual project or cumulative effects of multiple projects in an area. Industrial truck traffic can be detrimental to health-related air quality due to vehicle exhaust, as well as pose an increased risk of motor vehicle crashes.

In the *Revised Draft Supplemental Generic Environmental Impact Statement on The Oil, Gas and Solution Mining Regulatory Program*, the New York State Department of Environmental Conservation (NYSDEC) identified temporary but adverse noise and visual impacts from construction activity and increased truck traffic among the potential land-use environmental impacts associated with natural gas production (Witter et al., 2014). Significant adverse impacts in terms of damage to local and state roads could also result. Among mitigation measures described for environmental impacts, NYSDEC suggests imposing measures to reduce the adverse noise and visual impacts from well construction. A transportation plan could also be

Commented [EK185]: Please add OECD to the Acronyms List.

Commented [LBD186]: This section should be alongside material in the first para of this section that addresses some human health effects.

Commented [LBD187]: Is "pollution" the right term? Air pollution from traffic is addressed above, so perhaps just "traffic"?

required that would include proposed truck routes and assess road conditions along the proposed routes. Exhibit 6-5 tabulates the number of truck trips for a typical shale gas well (Massachusetts Institute of Technology [MIT], 2011).

Exhibit 6-5. Truck trips for a typical shale gas well drilling and completion

Activity	1 Rig, 1 Well	2 Rigs, 8 Wells
Pad and Road Construction	10–45	10–45
Drilling Rig	300	60
Drilling Fluid and Materials	25–50	200–400
Drilling Equipment (casing, drill pipe, etc.)	25–50	200–400
Completion Rig	15	30
Completion Fluid and Materials	10–20	80–160
Completion Equipment (pipe, wellhead, etc.)	5	10
Fracturing Equipment (pump trucks, tanks, etc.)	150–200	300–400
Fracture Water	400–600	3,200–4,800
Fracture Sand	20–25	160–200
Flowback Water Disposal	200–300	1,600–2,400
TOTAL	1,160–1,610	5,850–8,905

The large volumes of water involved in hydraulic fracturing operations can create high volumes of road traffic given the majority of the water used for fracking~~turing~~ is transported by truck. It should be emphasized that the large number of traffic movements shown in the table above are worst-case estimates. In particular, re-use of flowback wastewater significantly reduces the amount of road traffic associated with hauling water, which represents much of the traffic movement. Furthermore, large-scale operators are also using pipelines to transport water to the site, substantially reducing the amount of road traffic (MIT, 2011).

The Eagle Ford Shale Task Force Report for the RRC identified increased traffic and deterioration of roads and bridges among the infrastructure impacts from shale gas development (Porter, 2013). Exhibit 6-6 lists estimates of the number of truck-trips-per-shale-gas-well in the Eagle Ford (Porter, 2013).

Exhibit 6-6. Loaded truck trips per gas well

Activity	Number of Loaded Trucks
Bring well into production	1,184
Maintain production (per year)	Up to 353
Re-fracturing (every 5 years)	997

These impacts are enough of a concern that the task force considered alternative financing methods to help meet the increased demands on roads and bridges (Porter, 2013).

Upadhyay and Bu (2010) surveyed the visual impacts of Marcellus drilling and production sites in ~~PA~~Pennsylvania. They reviewed the drilling process, assessed direct visual impacts, and compared the results to the impacts of other technologies (e.g., windmills and cell towers). They also studied drill-pad density from map and aerial perspectives to examine the likelihood of seeing drill towers across a landscape, and the modeled potential impacts for increased drilling, making the following conclusions:

- Serious impacts from light and noise are a potential problem within a small radius of drilling sites.
- Indirect impacts like increased truck traffic, equipment storage, and temporary structures compose the most salient visual impacts, rather than the drill pads themselves.
- Timelines for site restoration of visual impacts vary significantly.

Upadhyay and Bu (2010) recommended that visual impacts be addressed during the siting and design phase and that nighttime impacts could be avoided by pointing lights downward.

The RFF (2013) report also gave several options in their survey of experts under the category of community disruption. Included in this category, as well as in the habitat fragmentation section, were such risks as light pollution, noise pollution, odor, and road congestion. The industry respondents identified a number of these community disruptions as risk pathways of high priorities, while the other respondent groups identified more conventional (e.g., air pollution, water pollution, etc.) risks.

6.4 Regulations and Strategies to Reduce Land Impacts

While there are very few regulations to reduce the impacts on land, habitat, noise, light, and traffic pollution, best practices have been developed in some cases.

6.4.1 Mitigation Options for Habitat Fragmentation Impacts

The NYSDEC (2011) study proposed that, if the development area included a region of continuous forest over 150 acres in size or a region of grassland over 30 acres, an ecological assessment should be conducted to identify best management practices.

A 2012 study of hydraulic fracturing practices in the Inglewood oil field in California, operated by the Plains Exploration & Production Company, proposed that the best way to mitigate habitat fragmentation impacts is to adopt best management practices, perform wildlife surveys, and implement restrictions during migration and mating seasons (Cardno ENTRIX, 2012). The study also found that ensuring that well pad reclamation occurs is the most productive method to reduce harm to populations (Cardno ENTRIX, 2012).

Avoiding disturbances to sensitive areas such as wetlands, waterways, and wildlife habitats when locating drilling sites could be the best method for mitigating impacts. Reclaiming the land upon completion of drilling activities is the best way to mitigate impacts in those cases when avoiding disturbances is impossible (NETL, 2009). Proceeding with reclamation processes as quickly as possible can minimize the disturbances, but all mitigation measures (including

avoiding disturbances to begin with) are subject to the landscape, plants, and wildlife that are present at a site.

The Western Governors' Association (2006) released a handbook outlining the best management practices for CBM development to be shared among the Association's shareholders. The practices are split into multiple categories, including planning, water, landowner relations, and infrastructure. Several subcategories can be applied to mitigating habitat fragmentation, such as protection of wetland areas, roads and transportation, pipelines and power lines, habitat and species protection, and wells. To protect wetland and riparian areas, facilities such as well pads should be sited outside of such regions as much as possible, and features that cut across the landscape, such as roads and pipelines, should avoid crossing wetlands and riparian areas as much as possible (Western Governors' Association, 2006).

Best practices for mitigating disturbance from roads and transportation include keeping road development to a minimum, using existing access roads as much as possible, using unimproved roads as little as possible during wet weather, following road construction and maintenance standards, avoiding sensitive areas, and attending to safety issues and other problems (Western Governors' Association, 2006). Recommendations of best practices for pipelines and other lines include using existing pathways, installing as many lines as possible in a single location, and using the least invasive construction equipment possible. To protect habitat and sensitive species, lines should be buried rather than installed above ground if possible. Well sites should minimize the amount of surface disturbance that occurs and should be reclaimed as quickly as possible upon completion of development activities (Western Governors' Association, 2006). Again, these best management practices have been developed in areas of CBM production by the Western Governors' Association, but many of these practices are applicable to shale gas development.

Commented [EK188]: NETL Team - my guess is that CBM production BMPs identified by WGA in '06 have indeed been applied to shale gas development sometime in the past 17 years. If we have to show the '06 date of this WGA study, I'm reluctant to include it - unless we can substantiate the BMPs referenced remain unchanged (which, with technology development and continuous improvement efforts I highly doubt). What do others feel? @Curry, Thomas @Skone, Timothy @Sweeney, Amy @Lavoie, Brian D.

Drilling on federal or public lands is subject to oversight by federal agencies, and sections of the Endangered Species Act may require that species of plants or animals not be threatened by the permitted drill site (NETL, 2009). Mandatory plans for mitigation and reclamation may be required to ensure that impacts on wildlife and habitat will be as minimal as possible (NETL, 2009).

Commented [EK189]: Please add ESA to the Acronym List.

With approximately 33 units of the National Park System in or near the Marcellus Shale, NPS found it important to be informed and current with development issues. Moss (2012) provides an overview of the geology, technology, current activity, and potential environmental impacts. Among the effects described are widespread development and well spacing, site space needs, water use, aquifer contamination, air quality, and truck transportation. There are then four recommendations to help park units prepare for potential shale gas development on and around NPS lands (Moss, 2012):

1. Check land and mineral ownership – Know if private in-holdings or private or state mineral estate underlie an NPS unit.
2. Be aware of industry interest adjacent to park boundaries – Land speculation, exploration, or drilling could signal increased requests for drilling permits. Contact the state oil and gas agency to express concerns and issues.

3. Work with state agencies – Meet with the state permitting agency, establish agreements, engage with stakeholders before issuance of permits, and if possible, have protective mitigation measures included directly in the lease.

The NPS Geologic Resources Division assists parks with policy and technical issues and reviews permitting and environmental documents to help mitigate or eliminate adverse impacts (Moss, 2012).

In January 2013, the BLM updated a presentation detailing best management practices for wildlife management that can help to minimize habitat fragmentation. The document offers several practices that can be implemented or planned to lessen impacts on habitat. The well pad itself and the immediate surroundings can be fit to the space available to minimize the disturbed area, rather than constructing a generic rectangular pad (BLM, 2013). There are also multiple examples of reclamation practices, both at the drill site and on access roads, that can be implemented to lessen the impact of the infrastructure. The well pad and supporting infrastructure (roads, pads, storage, and pipes) can be designed to be as efficient and minimally obstructive as possible (BLM, 2013). Wells can be remotely monitored using telemetry, pipelines and other lines can be buried where possible, and any existing corridors for roads and lines should be used whenever possible (BLM, 2013). It is helpful to monitor local wildlife populations to ensure that mitigation and reclamation measures are effective, and final reclamation upon abandonment of the well is critical to the long-term effectiveness of mitigation options (BLM, 2013).

6.4.2 Reducing Light Pollution

Even two decades after the establishment of designated programs by non-government organization(NGO)s to recognize and certify the quality of night skies and nighttime darkness resources, the very notion of what a "dark sky" is remains unsettled from a scientific standpoint (Crumey, 2014); while appropriate instrumentation can quantify night sky brightness, it cannot properly account for the human aesthetic experience of natural night. However, various lines of research increasingly suggest that unsafe thresholds of exposure to artificial light at night in terms of intensity, duration, wavelength, and timing likely exist for humans, plants, and animals. In this sense, light-sensing technologies applied in the field could effectively serve as "dosimeters" for monitoring these exposure parameters (Barentine, 2019).

6.5 DOE Research and Development and Analysis

An independent review of the literature suggests there is currently no [illegible] or analysis with respect to land use, habitat fragmentation, or light, noise, or traffic pollution being conducted by DOE.

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7 Social Justice and Natural Gas/Liquefied Natural Gas Market Development

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7.1 Introduction

Granting authorizations to import and/or export natural gas into and from the United States could potentially generate and, in some cases, ~~further~~ contribute to perpetuating~~e~~ instances of energy, environmental, and social injustice. Conversely, if potential impacts to disadvantaged and frontline communities[a] are both carefully considered and minimized, then opportunities to advance environmental, energy, and social justice may also be present. Ensuring the advancement of energy, environmental, and social justice across the domestic natural gas market, however, requires meaningfully engaging historically disadvantaged and frontline communities and ensures exposure to harms or burdens for these communities are prevented and minimized.

These types of considerations have driven the implementation of the Biden-Harris Administration's Justice40 initiative that was mandated under Executive Order 14008, and which has an explicit goal that 40 percent of the overall benefits from federal investments should flow to historically disadvantaged and disenfranchised communities and communities burdened by pollution. Specific types of projects include those related to the clean energy transition both in energy production and the advancement ~~for~~ of net-zero emission transportation. Additional categories include affordable housing and "green" workforce development and training, as well as those focused on ~~the~~ remediation of legacy pollution, clean water initiatives, and wastewater projects. Introducing the Justice40 (2023) framework to the ways in which government measures the distribution of investment benefits attempts to right the historical wrongs that have resulted in the unequal outcomes seen today by requiring the success of projects to be measured according to whom the benefits and burdens are distributed.

This chapter seeks to summarize the incorporation of social, environmental, and energy justice concepts found in the broader research literature as they relate to natural gas and LNG market development. The goal is to summarize what already exists and provide guidance as to how future research might be pursued at the nexus of social, energy, and environmental justice and project development. This literature review specifically focuses on the development of large-scale energy infrastructure intended to supplement the energy-transition goals outlined by the current administration and its policies. However, the challenge (and opportunity) researchers face in this space is rooted in the relatively less robust focus that has been spent on applying energy, environmental, and social justice concepts to the development of energy infrastructure projects specifically for natural gas and LNG markets.

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[a] Per the National Oceanic and Atmospheric Administration (NOAA), frontline communities are "those who are the most vulnerable to and will be the most adversely affected by climate change and inequitable actions because of systemic and historical socioeconomic disparities, environmental injustice or other forms of injustice" (NOAA, 2023).

Due to the nascency of research that links social, environmental, and energy justice issues with the development of natural gas and LNG markets, this literature review will cover research that has already connected these issues and weave together the separate literature areas into the discussion. For reference, this review uses the structure presented in Spurlock et al. (2022) that outlines a tractable framework to incorporate energy justice tenets into energy infrastructure planning decisions and deep decarbonization policy implementation strategies.

This discussion is further framed as a struggle to balance energy justice issues rooted in the unequal exposure to pollution and related burdens with the need to resolve where communities do not have equitable access to clean, affordable, and reliable energy. This chapter concludes by underscoring the idea that incorporating energy justice tenets (distributional, procedural, and recognition) must be done from the big-picture view of energy project governance as it is the point where all project planning, development, and implementation is most directly influenced. It is from the point of governance that the effort to ameliorate energy poverty through the implementation of environmental and energy justice can produce a just transition away from a GHG-intensive economy and toward a more sustainable outcome.

Commented [RK194]: While the application of a justice framework to this energy context is conceptual - there is a robust literature on socioeconomic and community impacts of UOG development in the last ten years. Will share a separate doc with recommendations.

Commented [RK195R194]: If these recommendations are included then a title "Societal Considerations, Impacts, and Justice in UNG and LNG infrastructure development"

Commented [BO196R194]: I think these recommendations on the impact of development efforts may be better suited to the follow-on effort to this chapter referenced by Tom Curry in Friday's call. They synch up with some of his descriptions of Natenna's recommendation that were more about the next logical extension of a chapter like this.

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7.2 Distributional, Procedural, and Recognition Justice

The three core tenets of energy justice are the assurance of distributional, procedural, and recognition justice, as shown in Exhibit 7-1 (Spurlock, Elmallah, and Reames, 2022). To aid in the understanding of the bigger picture of energy justice, the following subsections provide background on these three tenets.

Exhibit 7-1. Flow of energy justice decisions

Permission pending from (Spurlock et al., 2022)

7.2.1 Distributional Justice

Distributional justice is focused primarily on the equitable distribution of benefits and dis-benefits across communities (Spurlock et al., 2022). It is a concept focused on the well-being of individuals, which spans the gambit of human outcomes such as psychological well-being, societal well-being, and physiological well-being (Deutsch, 1975). Distributional justice delves into the nuanced context in which equity versus equality versus need may dominate in identifying unjust distributions.

Fairness is a key concept within distributional justice and can be characterized as a problem for geospatial analysis (Bouzarovski and Simcock, 2017). Across the energy supply chain, distributional justice is a problem of implied risk responsibility as well as costs and benefits (Heffron and McCauley, 2014). In addition to inequities created by a historical lack of inclusiveness is the risk that those structural deficits will compound under a changing climate. In other words, unless addressed, the deficits of the past will likely increase as the climate changes much like a revolving line of credit tends to grow faster over time when a balance is carried from one period to the next.

7.2.2 Procedural Justice

Spurlock et al. (2022) present procedural justice as essentially the effort to include all voices. This is the idea that disadvantaged communities are overburdened and underserved and their disenfranchisement can only be corrected when their voices are intentionally included in the start-to-finish process of project and policy development. In other words, stakeholder engagement must be done early and often to ensure the priorities of disadvantaged communities are codified in the priorities of the project or policy.

Procedural justice takes a more holistic view of outcomes from the perspective of group perception. Researchers break the impacts of procedural justice into three areas of effect: voice, dignitary process, and fair process. The voice effect is the positive behavior observed in communities engaged with a decision-making process when the individual feels heard. The effect of dignitary process is best described as respect. When an individual’s dignity is preserved, the community buy-in to the procedure grows. Finally, the fair-process effect describes the positive community behaviors that arise when the group perceives the existence of procedural justice. In a sense, the effect of fair process augments the effects of the dignitary process and the power of voice (Lind and Earley, 1992).

7.2.3 Recognition Justice

At its core, recognition justice deals with respect and consideration. Spurlock et al. (2022) present the concept as a demand to recognize that divergent views exist on the best pathways for energy project development and strategies to address issues of climate justice. Those views reflect the unique, diverse backgrounds of these communities who present the perspectives and opinions reflective of their histories. Incorporating those voices in the energy transition is critical to ensuring policymakers implement project development that seeks to serve all.

Equitable outcomes begin with the recognition that disenfranchised communities will require effort to enfranchise and empower their members to ensure their histories and perspectives are heard in a meaningful way.

Recognition justice seeks to provide for fair representation, safety, and the general creation of an environment that is welcome to all. McCauley et al. (2013) identify issues of recognition injustice in terms of how policy might treat those characterized as "energy poor" with the classic example of the behaviors of elderly household energy use. Looking at the overall higher average energy use, United Kingdom policymakers view the issue as an education problem where the assumption was that elderly people do not understand the long run impacts of small behavior changes. The authors reveal that framing choices in way that nudged elderly households toward the intended policymaker outcome required acknowledging that older people need warmer houses for their health and well-being. Strategies for changing behavior are more effective when normative behaviors within the community, culture, or ethnicity are recognized.

7.3 Energy Justice

Anchored by the three tenets of distributional, procedural, and recognition justice, energy justice acts as a guiding concept for activism (McCauley et al., 2013). A broad literature review on the topic of energy justice (Qian et al., 2022) shows that the recent growth and focus on energy justice has quickened in pace with the effort to incorporate renewable energy on the electric grid. Debating the definition of energy justice has been a robust area of discussion for researchers, but there exist a few core concepts that underpin most approaches. At its heart, assuring that energy justice deals with the issue of ~~addressing~~ energy poverty and branches out from the broader focus of environmental justice (Iwińska et al., 2021).

While focus on the justice of energy distribution is not new, it has grown in salience as the public increasingly accepts the need to transition from fossil fuels-based systems of energy production and consumption to clean alternatives. Using energy justice as a decision-making framework, Iwińska et al. (2021) outline the focus of this literature as one that seeks to consider how the policy-making framework surrounding the generation and consumption of energy can be fairer. In this sense, energy justice acts as a tool, helping to guide policy design.

On one hand, Iwińska et al. (2021) consider the energy justice concept as a "boundary object" whose conceit is to accelerate the inculcation of these principles in policymaker innovation and across all cultural boundaries—much like a change agent. On the other hand, these authors debate the merits of treating the concept as a standard rather than a boundary object. Standards on energy justice would more easily be incorporated into policy in tractable forms that are quantitative and qualitative, though likely at the loss of a unifying definition (Iwińska et al., 2021).

Digging beyond the core tenets of energy justice, Sovacool and Dworkin (2015) acutely characterize the conceptual metrics by which broader approaches to energy justice may be measured. Those include the need to measure the costs communities face with a special emphasis on the level of inequity across communities relative to the distribution of these costs. Sovacool and Dworkin (2015) also identify the need to distribute benefits to these same

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Commented [DN199R198]: I think it would be good to include other sources of applying energy/environmental justice for gas industry. Recommend reviewing DOE policy on implementing Justice 40 and addressing and developing metrics for incorporating energy justice in energy project implementation. Also be good to review API's recent report on environmental justice in oil & gas industry - https://www.api.org/news-policy-and-issues/environmental-justice

Commented [BO200R198]: Saving for future action per Friday's DOE meeting.

communities. Though it seems logical to measure the costs *and benefits* to disadvantaged and disenfranchised communities, historical focus has more often been on mitigating or compensating losers for costs rather than on how project design can seek to benefit disenfranchised communities. Their very disenfranchisement may relegate them to an after-the-event consideration (when considered at all), which highlights costs over benefits. The simple statement that benefits should be considered alongside costs may act to nudge the focus back toward before-the-event planning.

Sovacool and Dworkin (2015) list procedure as the critical element that can act to bridge the cost-benefit gap. The process by which energy project development flows can be exclusive by nature; this would naturally prohibit the participation of disenfranchised communities who, again by definition, are not empowered to advocate as robustly as the enfranchised communities.

Iwińska et al. (2021) outline the various foci of energy justice research. The current dominant topic has been renewable energy, as energy transition efforts have driven the growth of interest in energy justice. Summarizing the remainder of the subtopics of energy justice in broad terms, the research falls within the categories of energy poverty, energy policy, law, and governance.

Results from the transition away from fossil fuels are producing differentiated outcomes that vary by community. Energy justice studies reveal that some communities are clearly benefiting from the increased access to renewable energy technology and opportunities while others assume the burdens of change. Those communities that seem to be accruing the adverse health outcomes and increased cost of cleaner technology are the same historically disenfranchised peoples who often fail to reap the job gains and regional economic growth opportunities of change. Beyond this, the transition away from fossil fuel production harms local governments' ability to provide constituent services in cases where fossil fuels are dominant sources of economic activities. Nonprofit organizations tend to lead in the effort to ameliorate these inequitable outcomes (Carley, Engle, and Konisky, 2021).

Commented [RK201]: One aspect about the transition away from fossil fuel production relates to dependence of fossil fuel revenues, fiscal policy, and consequences to public service and infrastructure provision.

Pellegrini-Masini, Pirni, and Maran (2020) make the case that the prevalence of energy justice definitions inhibits the capacity of policymakers to deploy these concepts toward the greater good. They highlight several useful but nuanced approaches with Guruswamy (2010) underscoring the "energy oppressed poor" as those suffering from an inequitable distribution of energy as a resource, which is innately about distributional justice.

7.4 Energy Poverty and Energy Burden

Poverty is a dominant issue that arises often in research focused on energy. As policies are implemented to attenuate the worst effects of climate change, the focus on carbon emissions as a flow and stock[e] necessarily highlights how these costs are going to be born geospatially.

[e] The term "greenhouse gases" refers to those associated with atmospheric warming; however, GHGs are not uniform in how they affect the global warming process as their lifecycles vary. Carbon dioxide is considered a stock gas as it remains in the atmosphere for long periods. As such, it builds up over time like a "stock" of gas. CH_4 is a much shorter-lived GHG. It enters the atmosphere and remains for just about 12 years. As such, it is considered a gas that "flows" through the atmosphere with short-lived warming impacts for any one unit of methane.

Carbon mitigation policies themselves also present societal costs that are unequally burdening communities based on how much of the remaining carbon budget impoverished communities might need. But at its heart, energy justice is an issue of economic opportunity as access to safe, affordable energy is a necessity to meet basic human needs and pursue economic growth opportunities (Piwowar, 2022).

Bouzarovski and Petrova (2015) identify the criteria and conditions that drive energy poverty as the material and/or social deficit in energy services accrued by communities. The authors outline two key issues. First, deficits in domestic energy access and supply are the direct result of ineffective socio-technical mechanisms that fulfill energy demand at the household level of energy services such as heating and lighting. Second, "vulnerability thinking" often drives or exacerbates these outcomes. That is to say, the perceived likelihood of becoming impoverished can drive outcomes, frame processes, and generally lead to the undesired outcome as a result of historical perceptions or perspectives (Hall et al., 2013).

Okushima (2021) attempts to measure the "basic carbon needs" of a community. These are the total GHG emissions an individual community might bare to attain an "adequate level of domestic energy services." Okushima's case study of Japan highlighted that basic carbon needs varied based on differences in several factors within a community including the type of domestic dwelling, community demographics, and variation in climate characteristics across regions. Affluence allows people to shift away from GHG-intensive energy sources and can change basic carbon needs. Moreover, Okushima (2021) found that balancing the ability of all communities to meet their energy needs with decreases in their basic carbon needs is the critical factor for achieving some equitable progress on climate change.

The importance of energy poverty may have increased in recent years as a function of the world's increased attentiveness to climate change risks, but Campbell (1993) points to the 1970*s* oil crises as the flux point at which energy poverty challenges to political stability were revealed. Those latent risks to social cohesion were evident in communities dominated by lower incomes, access to inefficient heating technology, and sub-standard governmental guidelines for housing insulation. However, the sudden rise in oil prices catalyzed those latent risks into active disruptions that were exacerbated as policymakers introduced mechanisms to ration supply.

Campbell (1993) identifies the conceptual term "poverty" as an issue that confounds action on the problem of energy poverty. Poverty is identified as a multi-generational condition that permeates at the community-level without tangible points of action to take. To most, the state of poverty is a state of being. This is a challenge without boundaries—that formlessness tends to overwhelm policymaker action especially when considering the issue as multi-generational. Measuring those impacts on a quantifiable level is, therefore, a distinct challenge.

Energy poverty, on the other hand, is an energy infrastructure problem that capital expenditures can directly cure because household expenditures on fuel are quantifiable; therefore, a threshold exists in theory where energy poverty begins and ends (Campbell, 1993).

Campbell points to Boardman (1987) who posited that 10 percent of one's household income being spent on energy/fuel was the threshold of concern for energy poverty—a metric adopted by several others (Green et al., 2016; Lloyd, 2006; Lesser, 2015). While a large proportion of research identifies that spending above 10 percent indicated a state of energy poverty whereupon the cost of fuel consumption to meet one's energy service needs was a burden, some researchers have illustrated that threshold is 6 percent (Drehobl et al., 2020).

Follow-on research has expanded on this effort to measure energy poverty by creating a metric of threshold for energy poverty. While some countries have adopted specific metrics for measuring and comparing energy poverty (Faiella and Lavecchia, 2021), there is no clear consensus on best practices. Chapman and Scannell (2005) developed the Affordable Warmth Index based on the calculation of energy ratings to identify sources of energy that need efficiency investments by policymakers and households. Several others have made contributions, for example, Siksnelyte-Butkiene et al. (2021), Thomson and Snell (2013), Heindl (2013), Miniaci et al. (2014), Okushima (2016), and Brunner, Spitzer, and Christanell, (2012).

Regardless of the methodology for measuring energy poverty, the fundamental issue at hand is that the lack of affordable warmth changes people's basic daily routines. The onerous nature of accommodating these energy deficits tends to drive health and wealth outcomes for households (McCrone, 2015). The lack of affordable energy can bind communities to a lack of economic opportunity as they attempt to accommodate for energy deficits or their high costs, which tend to affect minorities and people of color more intensely.

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The myriad impacts of energy poverty on health are too numerous to cover in this document, but Faiella and Lavecchia (2021) outline several. Overall, households with limited incomes are energy poor and suffer from subsequent negative health outcomes (Thomson et al., 2017), for example, excess deaths during wintertime (McAvoy et al., 2007) with the elderly particularly at risk (de'Donato et al., 2013) and increasing seasonal variation due to climate change compounding these risks (Healy, 2003). For healthcare systems, this increased seasonal health risk can reduce economic activity and reduce the integrity of the broader healthcare system (Wells, 2007) with compounding effects to the system over time (Torjesen, 2012).

Negative outcomes tend to accumulate across multiple community contexts, but their effect is not felt in isolation. Rather, these negative community outcomes tend to have cumulative effects that interact and compound each other with the risk of cointegrated impacts higher with LNG project development (Gislason and Andersen, 2016).

7.5 Just Energy Transitions

The current energy transition presents a generational opportunity to make significant progress in ameliorating historical injustices (Wang and Lo, 2021). As technology has evolved and capital has flowed into large-scale energy infrastructure investments, a concerted effort to accrue the economic and social benefits associated with these technologies and investments in disadvantaged communities may prove fruitful in spurring a more just outcome from the energy transition. Equally possible is the ability to start mitigating the systemic injustices that have continued to plague these same communities in response to historical decision-making.

The articulation of energy transition goals varies significantly across the research literature, but it tends to boil down into a handful of broad topics.

These include poverty reduction (Lo and Broto, 2019; Koehn, 2008; Colenbrander et al., 2017), amelioration of historical energy injustices (Jasanoff, 2018; Delina and Sovacool,2018; Carley and Konisky, 2020), and opportunities for economic growth (Yang et al., 2018; Ehresman and Okereke, 2015). Wang and Lo (2021) argue that the energy transition is an apt vehicle for fixing historical wrongs if it can simultaneously account for environmental costs disadvantaged communities already suffer from, the reality that climate change will likely exacerbate these pre-existing environmental costs, and a decision-making process steeped in the tenets of assuring energy justice.

Pellegrini-Masini et al. (2020) attempt to prioritize the approach toward justice and the energy transition across four planes. First, the tradeoff in intergenerational outcomes and opportunities must be a prominent consideration for policymakers. This addresses the core reason that mitigating climate change is essential: subsequent generations should be provided the opportunity for growth and well-being that is at least commensurate with today's generations. Second, building out policy that considers energy vulnerability will help to prevent the transition from being a zero-sum game in which regional, fossil-fuel-reliant economies are left behind. In this sense, energy projects will benefit vulnerable communities. Third, transforming the social self-image of communities whose cultural identity is tied to fossil fuels must be considered to avoid confusing the energy transition with an attack on disadvantaged communities. Finally, the unavoidable damage to local communities must be accounted and compensated.

The ability to move forward into a new energy landscape that is sustainable is a direct function of the ability of policymakers to avoid repeating historical injustices; justice frameworks must be the bedrock of transition planning (Wang and Lo, 2021; Williams and Doyon, 2019). Pai, Harrison, and Zerriffi (2020) provide the framework for researchers to consider strategies for a just transition—one that preserves the well-being of fossil-fuel-reliant communities. Preserving the human capital of these communities is a critical goal for ensuring the energy transition policy provides opportunities for all. Pai, Harrison, and Zerriffi (2020) summarize more than a dozen requirements that would facilitate policymaker efforts to ensure a just transition but underscore one: the requirement of intentional effort for long-term planning with routine efforts to conscientiously engage with affected communities. Historically disenfranchised communities of people must be actively welcomed into the discussion early and often to be re-franchised and ensure their voices are heard (Weller, 2019).

7.6 Fossil Fuel Employment and Revenue

As the United States shifts away from a GHG-intensive economy, the delicate issue of fossil fuel unemployment arises. Specifically, the risk of unemployment rising as a result of the shift away from a GHG-intensive economy is pronounced in regions where fossil fuel and other extractive-based or refining industries have historically dominated available employment opportunities and been the core driver of local economic growth in the region. The loss of those jobs represents a significant loss to local government revenues, long-term declines in the economy, and a potential cycle of population loss under which the region cannot recover.

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The capacity to politicize energy transition debates is high (Healy and Barry, 2017) with GHG-intensive firms in a unique position to rally action against clean-energy projects (Goods, 2022) as a tradeoff between employment and climate policy. There is some merit to this concern from the community perspective as well. Female employment in the solar industry lags far behind male employment (Carley and Konisky, 2020) and disadvantaged or disenfranchised communities tend to bear a larger overall burden of costs even those associated with cleaner energy projects (Brock et al., 2021). To the extent that governance strategies can acknowledge the dignity of historically disadvantaged communities and groups, efforts to engage with those communities and groups in energy transition and governance strategies will be more successful and less divisive (Grossmann and Trubina, 2021).

Unions are viewed as an amenable structure for elevating and empowering the voices of disadvantaged communities in the energy transition (Pai, Harrison, and Zerriffi, 2020; Newell and Mulvaney, 2013). One reason may be in the high unionization rate of fossil-fuel industries (Pai and Carr-Wilson, 2018). Engaging with unions is in many ways a matter of practicality and the pre-existing internal structures built to advocate for their members make unions a strong vehicle for working toward a just transition[q] (Stevis and Felli, 2015). As an expansion of natural gas/LNG U.S. export capacity could limit the loss of employment for communities historically reliant on the fossil fuel industry, there exists an implicit advantage to directly approaching unions as potential enablers of cooperation with communities. Avoiding the mass loss of employment would help these communities from further decline as they tend to be areas in which the negative health and social impacts of fossil fuels are particularly pronounced.

Intentional efforts to diversify local economies would increase the resilience of local economies (Lobao et al., 2016). Notably, increasing the diversity of local economies is a positive regardless of the effort to transition away from fossil fuels. Any local economy highly dependent on one industry—particularly when that industry is as volatile as extractive-based industry—would introduce a greater resilience supportive of regional growth (Freudenburg and Gramling, 1994).

Among the opportunities a just transition presents are the ability to reduce the gender gap in regions dominated by the fossil fuel industry, increase investment into local energy infrastructure, remediate historical environmental damage, retrain the local workforce to "skill up" the region's human capital, and shore up local government revenues through economic diversification (Pai, Harrison, and Zerriffi, 2020).

In the end, just transitions are achieved when local voices are not just heard but amplified during the energy transition process. An unfortunate trend can play out that misses the mark on this issue where well-intentioned decisionmakers attempt to prescriptively advocate on behalf of disadvantaged communities. Often, policymakers advocate for the environmental protection of disadvantaged communities while neglecting to consider the calls for economic development emanating from those communities. A key example of that rests in the Canadian arctic where LNG projects that could act as local development opportunities for increasing local incomes are prevented by national policies that have banned energy projects out of the best intentions (Nicol and Barnes, 2019).

[q] The term "just transitions" originated within community-organizing efforts centered on labor unions (Eisenberg, 2018).

One obvious benefit of large-scale energy project development rests in the rents accrued from the project's completion. Treating these project benefits as a viable source of income that could be distributed to disadvantaged communities was explored in Chandrashekeran (2021), who studied indigenous populations in Australia after land repossession within Aboriginal populations. Chandrashekeran (2021) found that establishing property rights for historically disenfranchised populations is a key step in empowering collective negotiations for revenue sharing to fund reparations.

7.7 Protests and Political Activism

Excluding communities from decisions creates risks not just for disadvantaged populations, but for the completion of large-scale energy project development overall (Temper et al., 2020). The perpetuation of community disenfranchisement leaves people with a sense that the only option available for advocacy is to organize and protest. The way in which narratives are framed matters a great deal with respect to facilitating community buy-in for policy seeking to pivot away from fossil fuels.

Janzwood and Millar (2022) argue that the duality of natural gas—that it simultaneously accelerates the transition as a baseline electricity input and ensures the perpetuation of GHG reliance—creates the conditions for interpretive politics to dominate discourse around the transition. This is especially true for LNG organizations planning large energy infrastructure projects (Korkmaz and Park, 2019) and when regional economies are reliant on fossil fuels or the topic of natural gas as a "bridge fuel" is debated (Cha, 2020).

On the other side, anti-coal and anti-gas advocacy groups proved their own capacity to organize effectively in developed economies (Durand and Keucheyan, 2022). Social movements such as a the "UK Rights to Warmth" in the United Kingdom coalesced around the fight against entrenched energy poverty to some success (Walker and Day, 2012). Successful efforts to stop LNG export projects were found even in fossil fuel-friendly U.S. states such as Texas (Garrett and Sementelli, 2021) with access to social media and the strategic deployment of online networks increasing their efficacy (Correa-Cabrera et al., 2022).

The willingness to protest varies across cultures. Whereas communities within the United States that are at risk of job losses from national policies might tend to view justice as a regional tug of war that *must be* fought, research into Chinese activism shows that the Confucian perspective on justice as a collective outcome (whose goals are harmony between nature and humanity) shifts the perspective of the debate at its core (Wang and Lo, 2022). However, a nation or region's reliance on fossil fuels is not a reliable indicator of attitudes toward natural gas and LNG projects. Case in point, protestors in Canada and Norway have vehemently advocated against the expansion of oil and gas exploration despite their deep reliance on oil and gas production for both economies (Harrison and Bang, 2022). It has also been found that protests can arise in areas where there is a history of oil extraction when unconventional natural gas exploration is proposed (Chailleux et al., 2018).

The politicization of energy infrastructure can result in starkly divided factions, but the common thread of discontent that binds pro-gas and anti-gas contingencies is rooted in process.

Specifically, deficits in procedural and distributional justice tend to increase the likelihood of activism (Evensen, 2018; Temper et al., 2020).

7.8 Energy Governance and Adaptive Management

Governance structures play a vital role in the pursuit of energy project development and the transition away from fossil fuels, but their ability to provide an equitable or just transition is not guaranteed (Moss, 2009). Incorporating the concept of just outcomes begins with the governance structures of energy project development and planning (Newell and Mulvaney, 2013). Those who are in the position of governance are in a position of authority to inculcate more equitable outcomes to benefit disadvantaged populations (Florini and Sovacool, 2009).

As Florini and Sovacool (2009) point out, governance is not simply government. While governance is an activity in which governments participate it exists as a framework for creating and maintaining processes to implement policy. This framework is the conduit for participation that brings together government, intergovernmental organizations, private sector market participants, and communities to collectively manage a process that ideally serves all groups.

Governance is necessary as a result of two issues with which economists often wrestle. One issue is that society is not capable of ensuring equitable access to public goods without some overarching set of rules to facilitate that outcome and a governance structure to provide oversight over implementation. The second issue is that any economic or social activity tends to create what economists call “externalities.” That is, there are unintended results that can occur indirectly from the consumption of goods or social interactions. The decommissioning of a coal power plant is a prime example of the need for governance to protect the public’s well-being from externalities, as an idle power plant could become the source of negative health outcomes for a community without intentional efforts to prevent such outcomes. Governance structures are necessary to deal with these two conceptual issues because there is no economic incentive to do so (Florini and Sovacool, 2009).

Perspectives can clearly vary within communities and that variation can affect governance structures (Wang and Lo, 2021). In studying international natural gas markets, Norouzi (2022) notes that the heterogeneity of individual members within a collective community implies that international natural gas market outcomes are heavily influenced by individual preferences within any collective. Community engagement is important, but it is not the magic elixir that solves the problem by itself. Ciplet and Harrison (2019) identify three conflicts that emerge in efforts to facilitate an energy transition: 1) between inclusivity and sustainability where inclusive processes that invite community engagement require more time to complete projects; 2) between sustainability and the need to recognize the unique value system for each community, which increases the complexity of sustainability goal pursuits; and 3) between equity and sustainability, meaning that the distribution of costs and benefits can conflict with project performance.

The impact of a region’s political economy can also clearly drive outcomes. Inequality is a multi-dimensional concept that varies across countries and individuals (Laurent and Zwickl, 2021). As the communist states of the Eastern Bloc exited the Union of Soviet Socialist Republics, the effort to integrate into energy markets within the European Union revealed that variations in

culture and geography dominated some preferences in energy project outcomes with respect to energy justice (LaBelle, n.d.). On the other hand, a study of sub-Saharan African nations revealed a positive relationship between democracy, energy justice, and growth (Opoku and Acheampong, 2023). Cultural differences aside, income and wealth inequality may drive many of the outcomes. Studies of European Union attitudes toward sustainability policies show that 41 percent country-level variance in negative attitudes is correlated with differences in wealth and income (Pellegrini-Masini et al., 2021).

In short, the lack of consideration for energy justice issues within the global framework of energy governance will likely just perpetuate historical disadvantages within communities (Symons and Friederich, 2022). This is a function of existing power structures within current governance structures. Beyond that, Symons and Friederich (2022) show that the political sovereignty of communities making independent decisions over energy project development will always result in outcomes that serve each group's self-interest and ignore the externality problems. Without intentional adjustments to governance that deal with these structural problems, the current paradigm will continue to create winners and losers and perpetuate the current disenfranchisement of some communities.

Good governance strategies for energy project development require support from the government, reliable capital and operational funding, diversification goals for the economy, and diverse coalitions (Wang and Lo, 2021; Cha, Wander, and Pastor, 2020). Finally, the creation of ownership stake opportunities at the onset of project development for disadvantaged communities is critical to ensuring that the tradeoffs between disenfranchised communities and the regional benefits of energy projects ameliorate losses. Greater rates of acceptance have been found to exist within communities with larger ownership stakes in energy projects (Hogan et al., 2022).

7.9 Sustainable Development

The desire to balance environmental protection and economic development in disadvantaged and frontline communities has led to the championing of a concept called "sustainable development." Summarized broadly, the idea is to balance the needs of current generations without harming the well-being of future generations. Within this movement, the needs of today's impoverished communities are heavily weighted under the theory that gains in wealth and income of today's generation beget gains in tomorrow's generation. In other words, the benefits of economic development compound over generations (Poppel, 2018).

In practical use, the concept of sustainability can be vague (Grossmann et al., 2022). One oft-missing area of focus is the tradeoff between environmental protection advocacy for disadvantaged communities and advocacy with these same communities for energy justice and sustainable development. The concept of embedded sustainable development outlines criteria for energy project development to be measured in terms of how energy justice efforts compare to the energy privilege of communities (Ciplet, 2021).

In 2015, the United Nations outlined a list of 17 Sustainable Development Goals that define the focus of sustainability as a practice (United Nations, 2015). Oriented toward 2030 outcomes, the 17 outcomes broadly fall into Barbier's (1987) canonical "three systems" approach to

process development: environmental, social, and economic. Broadly speaking, the 17 goals break down into the promotion of clean water and sanitation services alongside sustainable cities and sustainable economic growth with full employment as well as the sustainable development of natural resources. They also promote the end to food insecurity and poverty, greater levels of societal health and well-being, lifelong inclusive/equitable educational opportunities, and gender equality, as well as strong judicial and governmental institutions. Finally, the United Nations (2015) advocates for the proactive implementation of climate change policy that results in energy infrastructure resilience where communities have access to reliable and affordable clean energy.

Cherepovitsyn and Evseeva (2020) proffer several criteria to promote sustainable development within the context of LNG project development in the arctic—an area currently receiving a great deal of attention for energy development projects. The authors note the importance of sustainable development in the arctic as it is home to over 20 percent of the world's hydrocarbon resources. To promote sustainable outcomes, they propose seven criteria of sustainable development goals[r]:

- Project development must minimize environmental impacts at the construction and operation site
- Natural resource use should be efficient
- Local community support is paramount as is the effort to preserve indigenous culture and heritage
- Long-run regional economic gains that benefit and reflect stakeholder expectations should be prioritized
- Larger energy infrastructure development goals are achieved
- Innovations to industry technology are achieved
- Strengthening the regional LNG market relative to the global network is achieved

7.10 Conclusion

Historical disenfranchisement of communities has often resulted in the creation of winners and losers with respect to policy impacts. To the extent that policy has created the conditions under which disadvantaged communities arise, those policies have likely been rooted in a fundamental lack of inclusivity in the planning and implementation processes of project development. As the United States continues to embark on a transition away from a GHG-intensive economy, the chance to right those historical wrongs presents itself.

DOE deploys the Climate and Economic Justice Screening Tool to identify disadvantaged communities. To do so, the tool pulls in geographic information system data on the universe of communities whose boundaries are defined by the U.S. Census. These communities are identified as disadvantaged if that census tract meets the criteria for disadvantage in one of the

[r] Note that while the framework for measuring outcomes by Cherepovitsyn and Evseeva (2020) focuses on the arctic, this approach may be prudent for any LNG project development strategy. As such, the seven points have been modestly edited to apply more broadly.

categories describing burden or if that community resides within the boundary of a federally-recognize tribe.

The panoply of burdens fall within a framework of several categories. The threshold for being considered disadvantaged under the Climate Change category is that the census tract is at the 90th percentile for agriculture loss, building loss, population loss, or flood and wildfire risk. For Energy, the census tract is at the 90th percentile for energy costs. For Health, the census tract is at the 90th percentile for asthma, diabetes, heart disease, or low life expectancy. For Housing, the census tract is at the 90th percentile for green space deficits, indoor plumbing, or lead paint exposure as well as they have experienced historical disinvestment in housing. For Legacy Pollution, the census tract is at the 90th percentile of exposure to facilities that have dealt with hazardous waste, former defense sites, are proximal to a superfund site or a risk management facility. For Transportation, the census tract is at the 90th percentile for exposure to various environmental particulates, face barriers to transportation access, or barriers due to volume. For Water and Wastewater, the census tract is at the 90th percentile for exposure to storage tanks or releases underground, or the discharge of wastewater. For Workforce Development, the census tract is at the 90th percentile for isolation by their linguistic background, poverty, unemployment, or an overall lower median income.

Currently, the tool identifies roughly 27,251 communities at the census tract level. The deployment of tools like this during the energy transition is key, particularly during the early planning stages, in creating the approach for community outreach, and in the effort to structure governance strategies. Identifying where disadvantaged communities are provides the high-level understanding into where deficits in outreach and inclusion have likely exacerbated the pervasiveness of disadvantage. In doing so, concerted efforts to bring these voices into the development of large-scale energy infrastructure projects related to natural gas/LNG market opportunities is key.

The calls to advocate for energy justice during this transition have grown as the salience of climate change threats grows. Achieving a just transition is largely a functioning of process. The once-in-a-lifetime opportunity to restructure current processes around the core concepts of distributional, procedural, and recognition justice is significant. Re-framing the foundations upon which critical U.S. energy infrastructure is built by bringing diverse voices and stakeholders to the planning table will help to ensure that the best laid plans produce results that facilitate the growth for all, not just some.

To do so, there is a need to accept the existence of frictions innate to energy justice and energy poverty. Providing economic growth opportunities in GHG-intensive regional economies is as paramount as the need for ensuring reliable, affordable, and clean energy for those suffering from a historic lack of energy access. This may require adjusting the method of measuring the benefits and costs of large-scale U.S. energy infrastructure investments. The implementation of the Biden-Harris Administration's Justice40 initiative speaks to this effort.

This chapter provides the framework for pursuing inclusivity goals in its discussion of energy justice and energy poverty. The energy transition is presented as a catalyst for pursuing change with the intended outcome being a just transition for all. In the end, the vehicle for applying

energy justice and energy poverty goals rests in the inclusive design of energy governance structures.

The literature base of energy justice and energy poverty within the space of natural gas and LNG market development is strong and growing. With intentionality, the authors of future research can help to ameliorate those historical disenfranchisements and provide a framework for the kind of shared prosperity that induces strong growth for all.

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NATIONAL ENERGY TECHNOLOGY LABORATORY

POTENTIAL ENVIRONMENTAL IMPACTS ASSOCIATED WITH UNCONVENTIONAL NATURAL GAS

July 21, 2023

DOE/NETL-2023/4388

DRAFT DELIBERATIVE PRE-DECISIONAL

INTERNAL USE ONLY – NOT YET APPROVED FOR PUBLIC RELEASE

Commented [TC1]: Global comment: is the EJ chapter consistent with the frame of "environmental impacts"? Should the title and introduction be "environmental and community impacts"? I'd like feedback from Kelli, Natenna, and Odysseus on this.

Commented [ST2R1]: Guidance to NETL: We are interested in your thoughts if the title is still accurate or should be changed to reflect that the addition of EJ and that the natural gas sections discuss both unconventional and conventional gas production.

Disclaimer

Hartej Singh[2]*: Writing – Original Draft;* ***Michael Marquis***[2]*: Writing – Original Draft;* ***Odysseus Bostick***[2]*: Writing – Original Draft;* ***Robert Wallace***[2]*: Writing – Original Draft;* ***Amanda Harker Steele***[1]**: Writing – Review & Editing, Supervision*

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Commented [ST3]: Header text needs to fit on one line.

The authors wish to acknowledge the excellent guidance, contributions, and cooperation of the NETL staff, particularly:

Commented [HSAJ4]: Comment for FE/HQ: We will update accordingly for final draft to reflect contributions.

Commented [STSR4]: Understood - thank you.

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TABLE OF CONTENTS

LIST OF EXHIBITS

ACRONYMS AND ABBREVIATIONS

AEO	Annual Energy Outlook
API	American Petroleum Institute
AR5	IPCC Fifth Assessment Report
B	Billion
Bcf	Billion cubic feet
BLM	Bureau of Land Management
BTEX	Benzene, toluene, ethylbenzene, xylenes
Btu	British thermal unit
CBM	Coalbed methane
CH_4	Methane
CMSC	Citizens Marcellus Shale Coalition
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_2e, CO_2-eq	Carbon dioxide equivalent
COGCC	Colorado Oil and Gas Conservation Commission
CRS	Congressional Research Service
d	Day
DOE	Department of Energy
DOI	Department of the Interior
EIA	Energy Information Administration
EDP	Exploration, development, and production
EPA	Environmental Protection Agency
FECM	Office of Fossil Energy and Carbon Management
FERC	Federal Energy Regulatory Commission
FP	Flowback and produced (water)
ft, FT	Foot
g	Gram
G&B	Gathering and boosting
gal	Gallon
GAO	Government Accountability Office
GHG	Greenhouse gas
GHGI	Greenhouse Gas Inventory
GHGRP	Greenhouse Gas Reporting Program
GWP	Global warming potential
H_2S	Hydrogen sulfide
HAP	Hazardous air pollutant
HPh	Horsepower-hour
IPCC	Intergovernmental Panel on Climate Change
kg	Kilogram
kJ	Kilojoule
km	Kilometer
km^2	Square kilometers
kWh	Kilowatt hour
LCA	Life cycle analysis
LNG	Liquefied natural gas
m^2	Square meter
m^3	Cubic meter
Mcf, MCF	Thousand cubic feet
min	Minute
MIT	Massachusetts Institute of Technology
MJ	Megajoule
MM	Million
MWh	Megawatt hour
N_2O	Nitrous oxide
NEIC	National Earthquake Information Center
NETL	National Energy Technology Laboratory
NGL	Natural gas liquid
NOAA	National Oceanic and Atmospheric Administration
NORM	Naturally occurring radioactive material
NOx	Nitrogen oxides
NPS	National Park Service
NSPS	New Source Performance Standards
NYSDEC	New York State Department of Environmental Conservation
O_2	Oxygen
OAC	Ohio Administrative Code
ONE Future	Our Nation's Energy Future
ORC	Ohio Revised Code
OSF	Oral slope factor
PA	Pennsylvania

PADEP	Pennsylvania Department of Environmental Protection
PM	Particulate matter
PRV	Pressure release valve
REC	Reduced emission completion
RFF	Resources for the Future
RfV	Reference value
RRC	Railroad Commission of Texas
scf	Standard cubic foot
SDWA	Safe Drinking Water Act
SF_6	Sulfur hexafluoride
SO_2	Sulfur dioxide
T	Trillion
T-D, T&D	Transmission and distribution
T&S	Transport and storage
Tcf	Trillion cubic feet
tCO_2	tonnes carbon dioxide
TexNet	Texas' Center for Integrated Seismicity Research
t NG	tonnes natural gas
Tg	Teragram
tonne	Metric ton
U.S.	United States
UIC	Underground Injection Control
USFS	U.S. Forest Service
USGS	U.S. Geological Survey
VOC	Volatile organic compound
WV	West Virginia
yr	Year

1 INTRODUCTION

The United States (U.S.) Department of Energy's (DOE) Natural Gas Regulatory Program is responsible for ~~granting authorizations~~reviewing applications to import and/or export natural gas from and/or to foreign countries. An important dimension ~~of~~ in considering whether to grant such authorizations is how the additional natural gas production and transport activities needed to support proposed actions ~~these exports and/or imports~~ may impact the environment. ~~As such~~Accordingly, ~~these~~ potential impacts are factors affecting the public~~'s~~ interest.[a]

Although fundamental uncertainties exist regarding the exact amount and location of natural gas production or transportation that would occur in response to additional authorizations being granted, it is important that DOE acknowledge and provide the public and decision-makers with access to updated information regarding the potential environmental consequences associated with such activities. Accordingly, DOE has prepared this update to the 2014 Addendum to Environmental Review Documents Concerning Exports of Natural Gas from the United States (hereafter the 2014 Addendum) to provide the public with an improved understanding of the potential environmental impacts associated with such activities (DOE, 2014).

We cannot estimate with certainty where, when, or by what method any additional natural gas would be produced, consumed, or exported in response to the granting of authorizations to import and/or export natural gas. Therefore, DOE cannot meaningfully analyze the specific environmental impacts associated with such activities. ~~As such, similar to~~Therefore, as with the 2014 Addendum, this report provides only a review of ~~the profusion of~~ peer-reviewed, scientific literature ~~produced~~ related to the potential environmental consequences of expanding natural gas production and related activities.

As unconventional natural gas production has represented an ever-growing share of U.S. natural gas production, the environmental impacts reviewed in this report relate primarily to those associated with unconventional production activities. The publications referenced build on a strong body of existing literature that traces the evolution of unconventional natural gas production techniques from their conceptual stages in the 1970s~~,~~ to the technology advancements that contributed to the shale gas boom of the early 2000s, as well as ~~and~~ further development of additional unconventional resources, including tight gas sands and coalbed methane (CBM) resources to the export of liquefied natural gas (LNG).

This report attempts~~makes every attempt~~ to summarize the published descriptions of the potential environmental impacts of ~~unconventional~~ natural gas ~~upstream~~ operations within the lower 48 states as detailed by government, industry, academia, scientific, non-governmental, and citizen organizations. The sources cited are all publicly available documents. While this

[a] DOE is responsible for considering the environmental impact of its decisions on applications to export natural gas, including liquefied natural gas (LNG), to countries with which the United States has not entered into a free trade agreement (FTA) requiring national treatment for trade in natural gas. (Applications for trade with FTA countries are deemed to be in the public interest by statute.) DOE conducts environmental reviews under the National Environmental Policy Act (NEPA) and as part of its public interest review under the Natural Gas Act (NGA).

Commented [TC6]: @Lavoie, Brian D. should we specify that this is for authorizations to non-FTA countries or is the use of this document broader to include all authorizations?

Commented [LBD7R6]: It's correct that this would only be used for non-FTA applications. (FTA applications are not subject to DOE NEPA review.) I'd suggest maybe just a footnote on this (see my suggestion), so as not to distract the reader at this early point. (Amy/Jen - please jump in if you have a different view.)

Commented [ST8R6]: Guidance to NETL: Add Brian's suggested footnote.

Commented [LBD9]: Suggest consider "may" and similar language that reflects uncertainties about impacts.

Commented [LBD10]: @Easley, Kevin do you suggest in-text treatment of this point vs. the footnote? I think it should be one or the other.

Commented [EK11R10]: I don't have a preference. But my sense is not everyone reading this Addendum will know what exactly goes into / governs a DOE 'public interest determination.' I defer to you and @Sweeney, Amy, @Lavoie, Brian D.

Commented [LBD12]: "such activities" near the end of this passage, at least textually as written, refers to "both conventional and unconventional natural gas markets" earlier in the passage. Suggest clarify to focus on unconventional, which is the topic of this report.

Commented [HSAJ13R12]: Done

report by no means represents an exhaustive list of the sources that discuss environmental consequences of upstream natural gas activities, the sources cited are ~~assumed~~ believed to be representative, and no significant areas have been excluded from the report. Multiple publications on similar topics are compared based only on their technical and methodological distinctions. Over the past decade, the focus of environmental issues has evolved with some interest in the public literature varying over time. Key research in some areas remains the same with minor to no new additions to the basis of scientific knowledge, in this situation some historical references have been maintained. No opinion on or endorsement of these works is intended or implied.

Commented [LBD14]: Can something be said like that the authors believe this survey is representative and no significant areas have been excluded from this review?

Commented [HSAJ15R14]: Done

This report is divided into chapters, each of which contains a separate section of references so that each type of environmental impact can be explored further. The types of environmental impacts that are documented in this review include the following:

- Greenhouse gas (GHG) emissions and climate change (Chapter 2)
- Air quality (Chapter 3)
- Water use and quality (Chapter 4)
- Induced seismicity (Chapter 5)
- Land use and development (Chapter 6)
- Environmental and social justice (Chapter 7)

In addition to containing information on potential environmental impacts, this report provides some background information on domestic natural gas production.

1.1 Natural Gas Basics

Natural gas is an odorless, gaseous mixture of hydrocarbons, largely made up of methane (CH_4) but also containing small amounts of natural gas liquids (NGLs) and nonhydrocarbon gases (e.g., carbon dioxide [CO_2] and water vapor) (EIA, 2023b). Natural gas is one of the major combustion fuels used throughout the country. It is mainly used to generate industrial and utility electric power, produce industrial process steam and heat, and heat residential and commercial spaces. The average gross heating value of natural gas is approximately 1,020 British thermal units per standard cubic foot (Btu/scf), usually varying from 950 to 1,050 Btu/scf.

Commented [ST16]: The HHV of natural gas used in the LCA work is 1,031 Btu/scf (54.1 MJ/kg) [60 deg F, 1 atm]. You need to specify HHV or LHV and at what standard conditions you are reporting. My understanding is that the oil & gas industry uses 60F / 1atm as the definition of "standard" conditions, while the industrial gas industry prefers 70F / 1atm.

Commented [HSAJ17R16]: Ask Harsh and Matt and simply adjust sentence to reflect.

Natural gas is typically classified as being either conventional or unconventional, depending on the permeability of the formation within which it is found, the production technology used to secure it, the current economic environment, and the scale, frequency, and duration of production from the resource (EIA, 2023b; Krieg, 2018).

Generally, conventional natural gas refers to natural gas found in highly permeable reservoirs, typically composed of sandstone or limestone, which allows for extraction to be completed in a relatively straightforward manner via vertical rather than horizontal drilling. Unconventional natural gas refers to natural gas found within low-permeability~~le~~ reservoirs; it is generally trapped within the pores (i.e., small, unconnected spaces) of rocks, which makes extraction more difficult and necessitates advanced drilling (e.g., directional or horizontal drilling) and well stimulation (e.g., hydraulic fracturing) techniques that are energy intensive (BP, 2017).

Innovations in existing oil and gas exploration and production technologies have revolutionized unconventional natural gas production in the United States. The production of natural gas from ~~U~~unconventional ~~natural gas~~ resources has not only ~~make~~ made up for declining conventional natural gas production but ha~~ve~~s also led to new levels of natural gas supply in the United States. This increased supply has contributed to an increase in the use of natural gas for power generation, manufacturing, transportation, and residential and commercial heating, as well as the ~~amount~~ availability of natural gas ~~being exported~~ for export from the United States.

There are three primary types of unconventional natural gas:[a]

- **Shale Gas:** refers to natural gas found within shale rock formations, which consist of fine-grained sedimentary rock that forms when silt and clay-size mineral particles are compacted together (Zendehboudi and Bahadori, 2017). Shale rock formations can be easily broken into thinner, parallel layers of rock. ~~Black shale, a dark-colored type of sedimentary shale rock containing organic-rich material, is also a source rock for unconventional natural gas (Ohkouchi, Kuroda, and Taira, 2015).~~
- **CBM:** refers to natural gas that is both generated and stored in coal beds. Originally extracted from coal mines to reduce the potential for explosions caused by an excess of CH_4 gas within the mine and subsequently disposed of, CBM now serves as an important source of energy. ~~Sequestering~~ Producing CBM from deeper, denser coal formations often requires the use of hydraulic fracturing technology.
- **Tight Sands Gas:** refers to natural gas found in low-permeability, gas-bearing, fine-grained sandstones, or carbonates.

Shale rock formations can contain significant accumulations of natural gas and/or oil. These formations are often referred to as "plays" and can be found in nearly 30 U.S. states. Operators in ~~T~~the Barnett Shale formation, which is located in Texas and is one of the largest onshore natural gas ~~fields~~plays in the United States, ha~~s~~ve been producing unconventional natural gas since the early 2000s (RRC, 2023). ~~It is one of the largest onshore natural gas fields in the United States.~~ While operators in the Barnett Shale formation still produce~~s~~ a significant amount of unconventional natural gas, the Marcellus Shale formation—located in the Appalachian Region of the United States and spanning Ohio, Pennsylvania, and West Virginia—is currently the largest ~~producer~~ source of unconventional natural gas from shale (EIA, 2023b).

Primary enabling technologies for accessing unconventional natural gas include hydraulic fracturing and horizontal drilling. Hydraulic fracturing (sometimes referred to as hydrofracking or simply fracking) is the process of pumping water mixed with a small amount of sand and other chemical additives (i.e., fracturing fluid) underground through a wellbore at a pressure

Commented [ST18]: NETL: we added this text for clarity. is it still appropriate to reference BP, 2017? Please confirm.

Commented [HSAJ19R18]: Does the new text impact the accuracy of the reference to BP 2017 or do we need to add an additional reference or move the BP reference.?

Commented [LBD20]: Should increasing exports be mentioned here, for completeness?

Commented [HSAJ21R20]: Adjusted

[a] There are other types of unconventional natural gas whose exploitation has not yet reached commercial scale. These include methane hydrate, which is a crystalline solid that consists of a methane molecule surrounded by a cage of interlocking water molecules. Methane hydrate is an "ice" that only occurs naturally in subsurface deposits where temperature and pressure conditions are favorable for its formation.

that is sufficient to cause a target rock formation to break (i.e., fracture) (USGS, 2019).[c] As the rock is fractured, natural gas that would have otherwise remained trapped is able to be released into a wellbore and returned to the surface (USGS, 2019).

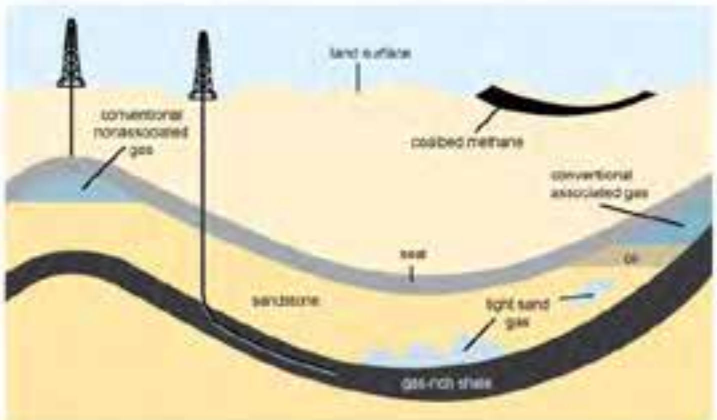
The i~~I~~nternal pressure caused by the fracturing of the rock formation also releases fluid, which travels to the surface through the wellbore. This fluid is commonly referred to as “flowback” or “produced water” and may contain the injected chemicals in addition to any naturally occurring materials found below the surface (e.g., brines, metals, radionuclides, and hydrocarbons). The fluid is typically stored on site in tanks or pits before it is treated and disposed of or recycled. In many cases, disposing of the fluid involves injecting it underground. In areas where underground injection is not an option, the fluid can either be reused or processed by a wastewater treatment facility and subsequently discharged into surface water.

Hydraulic fracturing has been applied since the late 1940s when Standard Oil of Indiana (later known as Amoco) developed the technique and performed some of the first fracture treatments in the Hugoton Gas Field in Kansas (BP, 2017). While the use of hydraulic fracturing is not limited ~~only~~ to wells that are horizontally drilled, the combination of horizontal drilling and hydraulic fracturing has increased the volume of domestic natural gas considered to be “technically recoverable” (i.e., able to be produced using currently available technology and industry practices regardless of any economic considerations).

The process of horizontal drilling involves first drilling a vertical well. Once a certain depth has been reached with the vertical well, the path of drilling is bent until the well begins to extend horizontally. Horizontal wells are not only longer than vertical wells, but the process is much more complex. ~~As such, a~~A horizontal well is therefore generally more expensive to drill than a vertical well, but it is expected to produce more natural gas (EIA, 2018). The horizontal section, sometimes referred to as ~~or~~ directionally drilled section,~~n~~ of a well can extend thousands of feet (ft). Exhibit 1-1 provides a schematic of conventional natural gas and the various types of unconventional natural gas resources described previously (EIA, 2023b). Exhibit 1-2 provides a schematic of the hydraulic fracturing process (BP, 2017).

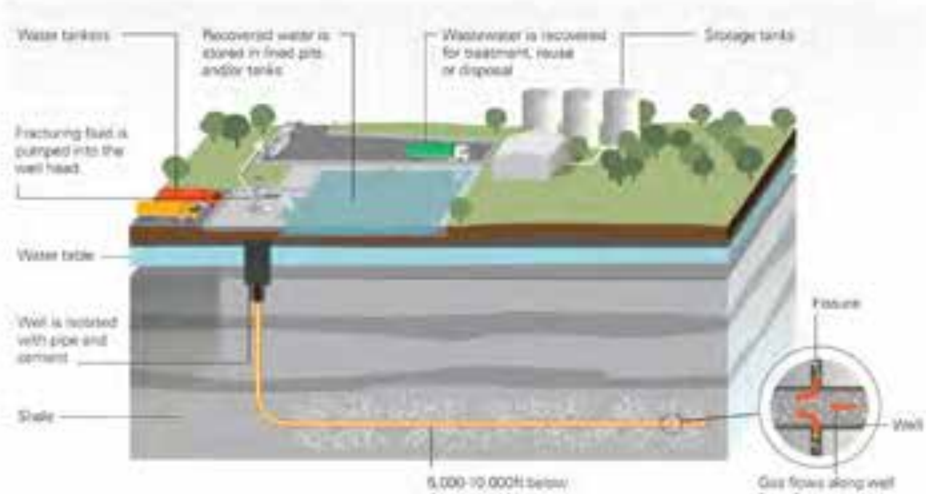
[c] The specific types of chemical additives used, and the proportions of each, depend on the type of rock formation that is being fractured. Additives function as friction reducers, biocides, oxygen (O_2) scavengers, stabilizers, and acids, all of which are necessary to optimize production. The composition of these fluids and the purposes of the additives are described in more detail in Chapter 4 – Water Use and Quality.

Exhibit 1-1. Schematic geology of natural gas resources



Source: Energy Information Administration (EIA 2023b)

Exhibit 1-2. Schematic geology of natural gas resources (3D)



Permission pending from BP (2017)

Commented [TC22]: I assume NETL has requested permission for all the figures, what is the timeline for getting these permissions in place?

Commented [ST23R22]: NETL: please create a graphic permission tracker with the received permissions contained/linked to archive with the project files. Thank you.

1.1.1 Liquefied Natural Gas

Liquefied natural gas (LNG) is natural gas that has been cooled to a liquid state (~~i.e., cooled to about~~approximately −260° Fahrenheit). The volume of natural gas in a liquid state is about 600 times smaller than ~~the volume of natural gas~~ in a gaseous state. Liquification of natural gas makes it possible to transport natural gas to places where pipelines currently do not exist or current pipeline infrastructure is unable to reach as well as for natural gas storage for end-use reliability ~~(e.g., abroad)~~. Liquefying natural gas is one way to allow markets that are far away from production regions to access natural gas. Once in liquid form, natural gas can be shipped to terminals around the world via ocean tankers and in some cases by LNG transport trailers (i.e., trucks). At these terminals, the LNG is returned to its gaseous state and transported by pipeline to distribution companies, industrial consumers, and power plants (DOE, 2021).

1.2 U.S. Natural Gas Resources

Annual U.S. production of dry natural gas was approximately ~~equal to~~ 35.81 trillion cubic feet (Tcf) in 2022 (an average of about 98.11 billion cubic feet [Bcf] per day). Production has mostly increased year over year since 2005 as hydraulic fracturing combined with horizontal drilling of shale, sandstone, carbonate, and other geologic formations has continued. About 70~~.4~~ percent of domestic dry natural gas production in 2021 was supplied by five of the United States's 34 natural gas-producing states. States with a larger percentage share of total U.S. dry natural gas production in 2021 include Texas (24.6 percent), Pennsylvania (21.8 percent), Louisiana (9.9 percent), West Virginia (7.4 percent), and Oklahoma (6.7%) (Exhibit 1-3) (EIA, 2023b).

Exhibit 1-3. U.S. natural gas production by state in 2021

Source: EIA (2023b)

Commented [TC24]: Are there years that it did not increase? I'd rather not use "mostly" unless necessary. Would prefer to say, "With the except of X years, production has increase year over year since 2005..."

Commented [HSAJ25]: Notes/Questions for FE-HQ:

1. State-Level production data is not yet available for 2022 from the EIA. Do you prefer we remove this figure?

Commented [ST26R25]: NETL: Keep figure BUT add to paragraph above the 2021 US dry gas production total put it in context to the 2022 value and support the 2021 figure. It is okay to state that 2022 state level data was not available at the time of report production in a footnote if you would like.

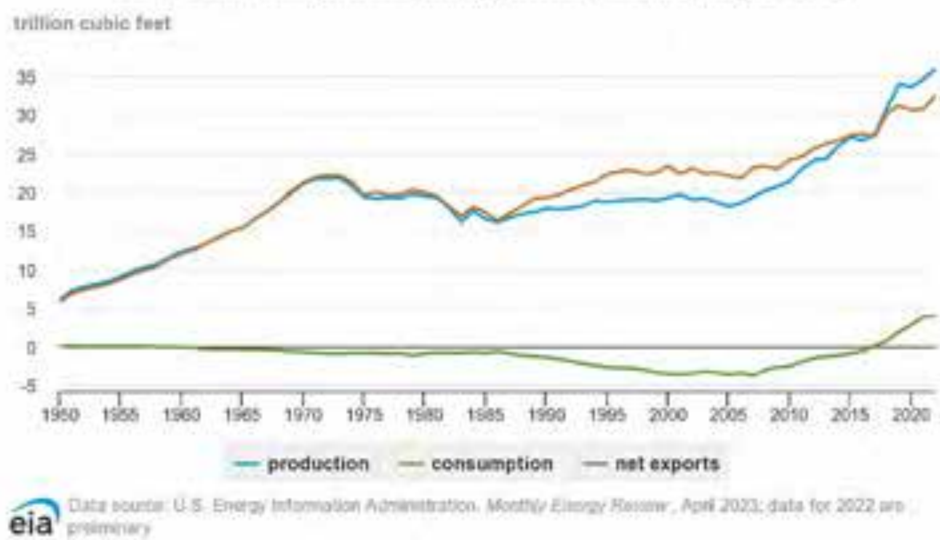
Commented [HSAJ27R25]: Add paragraph on 2021 dry production national volume to set up explanation.

In 2022, production from coalbeds accounted for about 2 percent of U.S. dry natural gas production, and supplemental gaseous fuels accounted for about 0.2 percent. Supplemental gaseous fuels include biogas (sometimes called renewable natural gas), synthetic natural gas, and other gases. Although most of the natural gas wells operated by the United States are located onshore, some wells are drilled offshore (i.e., into the ocean floor in waters off the coast of the United States). In 2022, offshore dry natural gas production was approximately equal to 0.80 Tcf, accounting for about 2.3 percent of total production. The majority—87.6 percent—of this production occurred in federally managed waters within the Gulf of Mexico (EIA, 2023c).

In addition to being a producer of natural gas, the United States is also a consumer and net exporter of natural gas. In 2022, the United States produced about 10.8 percent more natural gas than it consumed. While there was sufficient domestic production to meet our consumption requirements, the United States did import some natural gas, mostly from Canada. However, on a net basis, the United States was an exporter of natural gas. ~~; not enough, however, to no longer be considered a net exporter.~~ Exhibit 1-4 highlights recent (2022) and historical (1950–2021) U.S. natural gas production, consumption, and net exports (EIA, 2023c).

Commented [ST28]: NETL: we removed all discussion of projections from this document that followed Exhibit 1-4. Projections will be covered by the GCAM/NEMS work. Thanks.

Exhibit 1-4. U.S. natural gas consumption, dry production, and net exports (1950–2022)



Source: EIA (2023c)

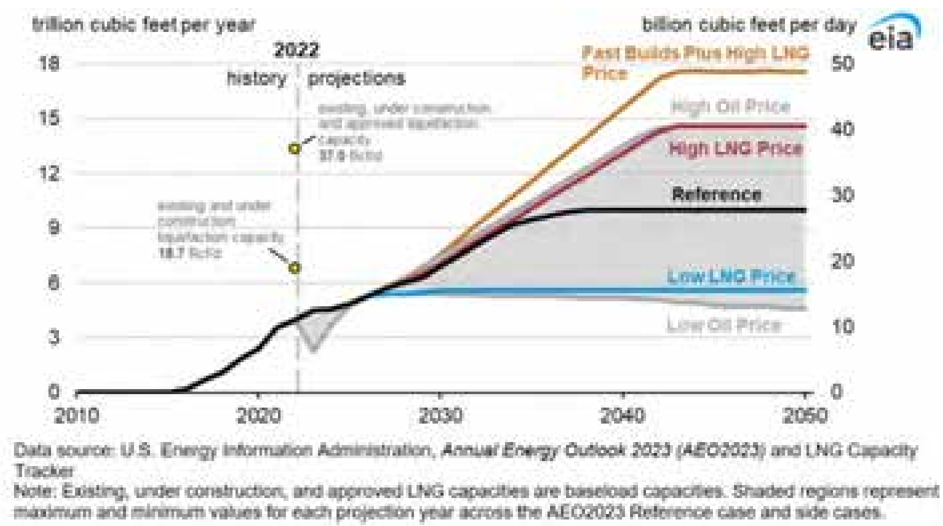
~~According to EIA's Annual Energy Outlook 2023 (AEO2023) reference scenario, domestic natural gas consumption is projected to decrease slightly but remain relatively constant out to 2050. Domestic natural gas production is projected to increase slightly and then also remain relatively constant out to 2050; see Exhibit 1-5 (EIA, 2023a).~~

~~*Exhibit 1-5. Natural gas consumption and dry production projections through 2050*~~

~~*Source: EIA (2023a)*~~

~~The AEO2023 reference scenario also projects that exports of natural gas, primarily LNG, will continue to increase between now and around 2035 (see Exhibit 1-6).~~

~~*Exhibit 1-6. U.S. LNG export projections through 2050*~~



~~*Source: EIA (2023a)*~~

1.3 U.S. Regulatory Framework and Federal Research and Development Programs

The following sub-sections provide a review of both federal and state regulatory responsibilities related to the production, transportation, use, and export of domestic natural gas resources.

1.3.1 Federal

Multiple federal agencies have authority over the production of unconventional natural gas resources. Three of these agencies—DOE, the Department of the Interior (DOI), and the Environmental Protection Agency (EPA)—play a critical role as they are charged with monitoring, assessing, and reporting on various environmental impacts Exhibit 1-5 describes the roles and responsibilities of these three agencies in more detail in addition to the way these agencies work together to inform policy-relevant science.

Exhibit 1-5. Key U.S. agencies and their roles in natural gas development and production

Source: DOE

EPA is in charge of regulating underground injection and disposing of wastewater resources and other liquids covered under the Safe Drinking Water Act (SDWA). They are also charged with regulating the air emissions covered under the Clean Air Act .

Federal agencies including EPA, DOI's Bureau of Land Management (BLM), the National Park Service (NPS), the Occupational Safety and Health Administration , and the U.S. Forest Service (USFS) are responsible for enforcing regulations for unconventional natural gas wells drilled on public lands. BLM is responsible for ensuring the environment of these lands remains protected and unaffected by natural gas production and other related activities.

USFS and BLM are both responsible for managing natural gas development on federally owned lands. Natural gas production and other related activities that will or do take place within the boundaries of our nation's national parks and other land managed by the ~~are the responsibility of~~ NPS, which establishes regulations to protect park resources and visitor values. Exhibit 1-6

Commented [HSAJ29]: Let today (7/31) conversation lead the way on approach to addressing revisions. Plan should be to consolidate. For each chapter see if it makes sense to move content in the chapter to this section of the report.

Commented [HSAJ30]: Maybe add a Venn Diagram of interaction between federal and state if we can. It may or may not be possible.

Commented [EK31]: Please add CAA to the Acronyms List.

Commented [EK32]: Please add OSHA to the Acronyms List.

provides some examples of federal statutes that apply to unconventional natural gas development.

Exhibit 1-6. Selected federal regulations that apply to unconventional oil and gas development

Statutes	Applicability
Clean Air Act	Places requirements on air emissions from sources of emissions at well sites; addresses compliance with existing and new air regulations, often delegated to local and state agencies. Generally, there is no distinction made between conventional and unconventional wells under the Clean Air Act.
Comprehensive Environmental Response, Compensation, and Liability Act	Only applies if hazardous substances besides crude oil or natural gas are released in quantities that require reporting. Natural gas releases do not require notification under the Comprehensive Environmental Response, Compensation, and Liability Act, but other hazardous substances may be released in reportable quantities during natural gas production.
Clean Water Act	Limits pollutants on produced water discharge under the National Pollutant Discharge Elimination System; stormwater runoff containing sediment that would cause a water-quality violation requires a permit under Clean Water Act decisions. Beneficial uses of surface waters are protected under Section 303.
Emergency Planning and Community Right-to-Know Act	Requires facilities storing hazardous chemicals above the threshold to report same and provide a Material Safety Data Sheet to officials and fire departments.
Endangered Species Act	Prohibits federal agencies from taking any action that is likely to jeopardize the continued existence of any endangered or threatened species (listed species) or result in the destruction or adverse modification of such species' designated critical habitat (Section 7); prohibits the taking of a listed species (Section 9); allows the Fish and Wildlife Service and National Marine Fisheries Service to issue a permit, accompanied by an approved habitat conservation plan, that allows for the incidental, non-purposeful "take" of a listed species under their jurisdictions (Section 10).
National Environmental Policy Act	Requires analysis of potential environmental impacts of proposed federal actions, such as approvals for exploration and production on federal lands.
Oil Pollution Act	Identifies spill prevention requirements, reporting obligations, and response planning (measures that will be implemented in the case of release of oil or other hazardous substances).
Resource Conservation and Recovery Act	Addresses non-hazardous solid wastes under Subtitle D. The Solid Waste Disposal Act exempts many wastes produced during the development of natural gas resources, including drilling fluids and produced water. EPA has determined that other federal and state regulations are more effective at protecting health and the environment.
Safe Drinking Water Act	Prevents the injection of liquid waste into underground drinking water sources through the Underground Injection Control (UIC) program. Fluids other than diesel fuel do not require a UIC permit. The UIC program gives requirements for siting, construction, operation, closure, and financial responsibility. Forty states control their own UIC programs.

1.3.1.1 Bureau of Land Management

BLM manages the U.S. government's onshore subsurface mineral estate, an area of about 700 million (MM) acres held jointly by BLM, USFS, and other federal agencies and surface owners.

Natural gas produced from the U.S. government's onshore subsurface mineral estate represents a significant portion of our nation's energy mix. In fiscal year 2022[4], sales of oil, gas, and natural gas liquids produced from the U.S. government's onshore subsurface mineral estate accounted for approximately 11 percent of all oil and 9 percent of all natural gas produced in the United States. About 23 MM acres had been leased to natural gas developers by the end of that year, and about 12.4 MM of those acres were producing natural gas in economic quantities (BLM, 2023). BLM published a rule regulating fracking on public lands on March 26, 2015—this rule was rescinded on December 28, 2017 (Fitterman, 2021).

Commented [TC33]: BLM proposed rules to regulate methane releases in federal lands in 2021. Interior Department Takes Action to Reduce Methane Releases on Public and Tribal Lands | Bureau of Land Management (blm.gov)

Commented [ST34R33]: NETL: please add the 2021 rule to the discussion.

Commented [TC35]: I recommend revising this section to generally discuss EPA's role establishing regulations for air, GHG emissions, and water. The specifics on each could then be moved to the appropriate sections in the chapters.

Commented [ST36R35]: NETL: Note global guidance is to consolidate at a high level the regulatory discussion within Chapter 1. Please disregard the following part of the comment form Tom above " The specifics on each could then be moved to the appropriate sections in the chapters."

Commented [HSAJ37R35]: First part of Tom's comment should still be addressed.

1.3.1.2 *Environmental Protection Agency*

EPA's New Source Performance Standards (NSPS) under the CAA set the regulations for emissions sources from the oil and natural gas sector. Exhibit 1-7 illustrates the scope of NSPS established to-date and the way regulations have evolved in scope since 2012 (EPA, 2021).

Exhibit 1-7. Natural gas sources covered by EPA's proposed NSPS and Emissions Guidelines, by site

Location and Equipment or Process Covered	Required to or Would be Required to Reduce Emissions under EPA Rules (if finalized as proposed)	Rules that Apply			
		2012 NSPS for VOCs (OOOO)	2016 NSPS for Methane & VOCs (OOOOa)	2021 Proposed NSPS for Methane & VOCs (OOOOb)	2021 Proposed Emissions Guidelines for Methane (OOOOc)
Oil and Natural Gas Well Sites					
Completions of hydraulically fractured wells	✓	•	•	•	
Compressors at centralized tank batteries	✓			•	•
Fugitive emissions	✓		•	•	•
Liquids unloading	✓			•	
Pneumatic controllers	✓	•	•	•	•
Pneumatic pumps	✓		•	•	•
Storage vessels	✓	•	•	•	•
Sweetening units	✓	•	•	•	•
Associated gas from oil wells	✓			•	•
Natural Gas Gathering and Boosting Compressor Stations					
Compressors	✓	•	•	•	•
Fugitive emissions	✓		•	•	•
Pneumatic controllers	✓	•	•	•	•
Pneumatic pumps	✓			•	•
Storage vessels	✓	•	•	•	•
Sweetening units	✓	•	•	•	•
Natural Gas Processing Segment					
Compressors	✓	•	•	•	•
Fugitive emissions	✓	•		•	•
Pneumatic controllers	✓	•	•	•	•
Pneumatic pumps	✓		•	•	•
Storage vessels	✓	•	•	•	•
Sweetening units	✓	•	•	•	•
Transmission and Storage Segment					
Compressors	✓		•	•	•
Fugitive emissions	✓		•	•	•
Pneumatic controllers	✓		•	•	•
Pneumatic pumps	✓			•	•
Storage vessels	✓	•	•	•	•

[1]Covered for SO_2 only; [2]Covered for VOCs only

Source: EPA

EPA's Greenhouse Gas Reporting Program (GHGRP) requires reporting of GHG emissions data and other relevant information ~~to be reported~~ by large sources of emissions, including fuel and industrial gas suppliers and CO_2 injection sites (EPA, 2023). The data reported is available to businesses, stakeholders, and other [illegible]s interested in tracking and comparing the GHG emissions of facilities, identifying opportunities to reduce emissions, minimizing wasted energy, and saving money. ~~States, cities, and communities can also use EPA's GHG data to identify high-~~

[4] October 1, 2021 through September 30, 2022

~~emitting facilities in their areas, compare emissions between similar facilities, and develop common-sense climate policies for constituents.~~ The petroleum and natural gas industry is covered under Subpart W of EPA's GHGRP. Unconventional natural gas production is covered under the provisions for onshore production, natural gas processing, natural gas transmission, and LNG storage and import/export. Annual CO_2, CH_4 and nitrogen oxides (NOx) emissions must be reported separately for each of these segments.

EPA studied the relationship between hydraulic fracturing for oil and natural gas and drinking water resources (EPA, 2022a). The study includes a review of published literature, analysis of existing data, scenario evaluation and modeling, laboratory studies, and case studies. EPA released a progress report in December 2012, a final draft assessment report for peer review and comment in June 2015, and the final report in December 2016. The final EPA report concludes that hydraulic fracturing activities can impact drinking water resources under some circumstances and identifies factors that influence these impacts.

A core element of the SDWA UIC program is setting requirements for proper well siting, construction, and operation to minimize risks to underground sources of drinking water. The Energy Policy Act of 2005 excluded hydraulic fracturing (except when diesel fuels are used) for oil, natural gas, or geothermal production from regulation under the UIC program. This statutory language caused regulators and the regulated community alike to raise questions about the applicability of permitting practices. As a result, EPA developed revised UIC Class II permitting guidance specific to oil and natural gas hydraulic fracturing activities using diesel fuels (EPA, 2022a). Although developed specifically for hydraulic fracturing where diesel fuels are used, many of the guidance's recommended practices are consistent with best practices for hydraulic fracturing in general, including those found in state regulations and model guidelines for hydraulic fracturing developed by industry and stakeholders. Thus, states and tribes responsible for issuing permits and/or updating regulations for hydraulic fracturing will find the recommendations useful in improving the protection of underground sources of drinking water and public health wherever hydraulic fracturing occurs. The guidance outlines for EPA permit writers, where they are the permitting authority, (i) existing Class II requirements for diesel fuels used for hydraulic fracturing wells, and (ii) technical recommendations for permitting those wells consistently with these requirements (EPA, 2022a).

EPA completed a stakeholder engagement effort in 2020 that sought input on how the agency, states, tribes, and stakeholders regulate and manage wastewater from the oil and gas industry. EPA released a draft report in May 2019 that described what it heard during its engagement for this study (EPA, 2022a). EPA accepted public input on the draft report and, after considering this input, published a final report. In many regions of the United States, underground injection is the most common method of managing fluids or other substances from shale gas extraction operations. Management of flowback and produced water via underground injection is regulated under the SDWA UIC program. The Clean Water Act effluent guidelines program sets national standards for industrial wastewater discharge to surface waters and municipal sewage treatment plants based on the performance of treatment and control technologies. Effluent guidelines for onshore oil and natural gas extraction facilities prohibit the discharge of pollutants into surface waters, some permit exception may allow for discharge under unique conditions. ~~, except for wastewater that is of good enough quality for use in~~

Commented [LBD38]: Please check timing/dates – 2020 engagement was reported on in 2019?

Commented [LBD39]: Citation?

Commented [EK40]: Please add CWA to the Acronym List.

~~agricultural and wildlife propagation for those onshore facilities.~~ On June 28, 2016, EPA promulgated pretreatment standards for the Oil and Gas Extraction Category (40 Code of Federal Regulations Part 435). These regulations prohibit discharge of wastewater pollutants from onshore unconventional oil and natural gas extraction facilities to publicly owned treatment works.*

On December 6, 2022, EPA issued a supplemental proposal to update, strengthen, and expand standards intended to significantly reduce emissions of GHG and other harmful air pollutants from the Crude Oil and Natural Gas source category (EPA, 2022b). First, EPA proposed standards for certain sources that were not previously addressed. Second, EPA proposed revisions that strengthen standards for sources of leaks, provide greater flexibility to use innovative advanced detection methods, and establish a super-emitter response program. Third, EPA proposed to modify and refine certain elements of the proposed standards in response to information submitted in public comments. Finally, EPA proposed details of the timelines and other implementation requirements that apply to states to limit CH_4 pollution from existing designated facilities in the source category under the CAA ~~Clean Air Act~~ (EPA, 2022b).

Commented [LBD41]: Is there anything that can be said at the end of the paragraph on current status? Or timeline expected for final rule?

Commented [HSAJ42R41]: If it is significant it may be worth noting what is in process. But we don't want to mention what will happen. Take an agnostic approach and mention it is in progress.

1.3.1.3 Department of Energy

The NGA ~~Natural Gas Act~~ requires DOE to make public interest determinations on applications to export LNG to countries where the United States does not have existing free_-trade agreements requiring national treatment for trade in natural gas. The Office of Fossil Energy and Carbon Management's (FECM) natural gas import–export regulatory program is implemented by the Division of Regulation in the Office of Regulation, Analysis, and Engagement. Typically, the Federal Energy Regulatory Commission (FERC) has direct regulatory responsibility over the siting, construction, and operation of onshore LNG export facilities in the United States. In these cases, FERC leads the environmental impact assessments of proposed projects consistent with the National Environmental Policy Act, and DOE is typically a cooperating agency as part of these reviews (DOE, 2023a). Similarly, for offshore LNG export facilities, the Department of Transportation's Maritime Administration is responsible for environmental reviews, in coordination with the Coast Guard, guided by requirements in the Deepwater Port Act. Again, DOE is typically a cooperating agency in these reviews. In some limited circumstances, DOE is the lead agency for NEPA reviews related to proposed LNG exports.

Commented [EK43]: Please add NEPA to the Acronym List.

Commented [EK44]: Please add both DOT and MARAD to the Acronym List.

Commented [EK45]: Please add USCG to the Acronym List.

FECM's Point Source Carbon Capture Division's research, development, demonstration, and deployment portfolio facilitates the development of technologies and infrastructure that improve performance, reduce costs, and scale the deployment of technologies to decarbonize the industrial and power sectors and remove CO_2 from the atmosphere. Within the natural gas supply chain, these efforts include research and commercial-scale demonstration of

* "Publicly owned treatment works" is a term used in the United States to designate a sewage treatment plant owned, and usually operated, by a government agency. In the United States, publicly owned treatment works are typically owned by local government agencies and are usually designed to treat domestic sewage and not industrial wastewater.

technologies that advance carbon capture and storage on natural gas-fired power plants and industrial natural gas combustion streams (DOE, 2023a).

FECM is working to support efforts to decarbonize LNG terminals through ~~deployment~~ exploration of technical and economic feasibility of carbon capture on gas separation and combustion streams and the use of electric motor drives supplied by net-zero emissions electricity. Decarbonizing LNG terminals is a key part of the effort to reduce life cycle emissions associated with the export of natural gas to global allies. ~~Additionally, DOE has regulatory responsibilities related to LNG. Companies that want to export LNG must get authorization to do so from FECM.~~

FECM's Methane Mitigation Technologies Division aims to eliminate non-trivial fugitive and vented CH_4 emissions from the natural gas supply chain to reduce the climate impacts from the production and use of natural gas. The division is focused on developing accurate, cost effective, and efficient technology solutions and best practices to identify, measure, monitor, and minimize CH_4 emissions from these sources. DOE has funded several technology investigations through NETL that deal with produced water management and life cycle assessments of the natural gas value chain (DOE, 2023b).

DOE's shale gas research program brings together federal and state agencies, industry, academia, non-governmental organizations, and national laboratories to develop technologies that enable safe, environmentally sustainable oil and gas production. DOE's shale gas research program is tasked with calculating the risks of oil and gas exploration and production undertakings. ~~DOE has funded several technology investigations through NETL that deal with produced water management and life cycle assessments of the natural gas value chain (DOE, 2023b).~~

On April 21, 2023, a Request for Information was issued by FECM to obtain input to inform DOE's research and development activities within the Office of Research and Development's Methane Mitigation Technologies Division and the Office of Carbon Management Technologies' Point Source Carbon Capture Division. In addition, such data and information could help inform the Office of Regulation, Analysis, and Engagement's capabilities to assess natural gas import and/or export applications ~~under the Natural Gas Act of 1938, as amended~~. Through the R~~equest for Information~~, DOE ~~is~~ requesteding information on strategies and technologies that natural gas and LNG companies are deploying, or could deploy, to reduce GHG emissions and other air pollutants associated with natural gas delivered to liquefaction facilities, housed at liquefaction facilities, and being loaded, transported, and delivered to regasification facilities (DOE, 2023a).

1.3.2 States

States have the power to implement their own requirements and regulations for unconventional natural gas drilling that are equivalent to or more stringent than established federal practices. ~~with federal oversight.~~ All states that produce natural gas have at least one agency charged with issuing new permits for production wells. While state requirements for permits can differ, any requirements set forth by federal regulations must be met for a state-level permit to be issued.

Commented [ST46]: We issued an RFI, but do we have funded work on these paths today?

Commented [ST47R46]: NETL: we softened this language as we have not funded CCS or electric motor conversion to support the verb "deployment".

Commented [HSAJ48R46]: No answer on top question required. Double check changes don't impact author's point/message.

Commented [ST49]: This sentence is broader than Shale Gas Research and better aligns to the Methane Mitigation paragraph above for the LCA work. Produced water is in a different program line as well.

Commented [HSAJ50R49]: Moved sentence so just double check it is still within context.

Commented [EK51]: Please add NGOs to the Acronym List.

Commented [ST52]: This sentence is broader than Shale Gas Research and better aligns to the Methane Mitigation paragraph above for the LCA work. Produced water is in a different program line as well.

Commented [ST53R52]: NETL: We moved the sentence. Please confirm you are okay with the move.

Commented [EK54]: Please add RFI to the Acronym List.

Commented [EK55]: Please add R&D to the Acronym List.

NETL evaluated the state regulatory programs for oil and natural gas production for their applicability and adequacy of protecting water resources (NETL, 2014). NETL ~~also~~ reviewed regulations for permitting, well construction, hydraulic fracturing, temporary abandonment, well plugging, tanks, pits, and waste handling and spills. This evaluation revealed several key messages (NETL, 2014):

1. State oil and gas regulations are adequately designed to directly protect water resources through the application of specific programmatic elements such as permitting, well construction, well plugging, and temporary abandonment requirements.
2. Experience suggests that state oil and gas regulations related to well construction are designed to be protective of groundwater resources relative to the potential effects of hydraulic fracturing. However, development ~~and dissemination~~ of best management practices related to hydraulic fracturing would assist states and operators in ensuring continued safety of the practice, especially as it relates to hydraulic fracturing of zones near groundwater, as determined by the regulatory authority.
3. Many states divide jurisdiction over certain elements of oil and gas regulation between the oil and gas agency and other state water protection agencies. This is particularly evident in the areas of waste handling and spill management.
4. The implementation and advancement of electronic data management systems has enhanced regulatory capacity and focus. However, the inclusion of more environmental data is needed, as well as further work in the areas of paper-to-digital data conversion.

In 2014, EPA compiled a summary of state regulatory programs for oil and natural gas exploration, development, and production (EDP) solid waste management. This review was conducted by EPA personnel in the Office of Resource Conservation and Recovery within the Office of Solid Waste and Emergency Response ~~and. The review~~ included relevant regulations for Ohio, Oklahoma, Pennsylvania, Texas, and West Virginia, which are presented below ~~that help to drive sustainable practices within these leading oil and gas producing states~~ (EPA, 2014).

1.3.2.1 Ohio

Regulations concerning technical requirements for waste pits are found in Chapter 1501 of the Ohio Administrative Code (OAC) and Rule 1509 of the Ohio Revised Code (ORC), which contains the statutory authority for the regulations promulgated in the OAC as regulated by the Division of Mineral Resources Management in the Department of Natural Resources. The complete set of applicable regulations can be found in Appendix OH-3. Regulations relevant to this addendum include the following:

- OAC 1501:9-1-02 details the requirements for the permitting of wells, including the plan for disposal of water and other waste substances resulting from oil and gas exploration and production activities.
- OAC 1501:9-3-08 details temporary storage of saltwater and other related waste, including design criteria for storage pits.

Commented [TC56]: States also have authority to regulate air emissions from facilities. I would recommend deleting the detailed summary of the adequacy of protecting water resources and include a high-level discussion of state authorities to regulate oil and gas production and associated impacts.

Commented [EK57]: Should we add language that indicates these state O&G regulatory programs, originally summarized in 2014, remain essentially unchanged and continue to be highly effective? Do we have current or recent information that confirms that state of play nearly a decade later? Just concerned potential gas development opponents will consider state regulatory regimes - if they are essentially unchanged in the past decade might be deemed potentially lacking given the U.S. is now a net natural gas exporter?

Commented [ST58R57]: NETL: we are strongly concerned that a 2014 summary is no longer accurate. Can you confirm your summary is current? If yes, please explain. If not, then we need to pull this back to a higher level discussion of the role that states have in regulating solid waste from NG operations. This comment is in line with HQ's broader comments on accuracy of regulatory sections with respect to representing current landscape.

Commented [HSAJ59R57]: Latest consolidated analysis of states - but we should likely take this out because it is dated.

Commented [HSAJ60]: States can be consolidated into one general section but could reference "following x states are leading in regulatory space." Want to avoid calling out specific state w/o providing context for why specific states are highlighted. Might be better to break it out by impact - water, seismicity, etc.

Commented [HSAJ61]: Could summarize what is in the bullets at a high-level but **also provide link to "latest" regulations.**

- OAC 1501:9-9-05 specifies tank location restrictions, including setbacks from public roads, inhabited structures, wells, heaters, and other equipment.
- OAC 1501:9-9-03 requires pits of sufficient size and shape to be constructed adjacent to each drilling well to contain all the drilling muds, cuttings, saltwater, and oil.
- OAC 1501:9-9-05 specifies that where a hazard exists, any production equipment at the wellhead and related storage tanks must be protected by an earthen dike or earthen pit with a capacity to contain any substances produced by operation of the related oil or gas well.
- ORC 1509.072 discusses the obligation to restore the land surfaces after drilling operations have ceased, including removing all equipment, revegetating the affected area, preventing sedimentation and erosion, and authorizing the chief retains in the closure of a well.
- ORC 1509.22 discusses the prohibition of water contamination and covers storage and disposal of brine. This section also discusses the storage of waste fluids and the management allowances for these fluids.

1.3.2.2 Oklahoma

Regulations concerning technical requirements for oil field waste pits in Oklahoma are found primarily in Oklahoma Administrative Code, Title 165, Chapter 10, Subchapters 3 and 7 as regulated by the Oklahoma Corporation Commission Division of Oil and Gas. Regulations relevant to this addendum include the following:

- 165: 10-7-16 details minimum technical design standards for waste pits.
- 165:10-7-5 details operating requirements for pits, specifically operating standards in the event of a discharge, including reporting details and requirements along with record-keeping requirements.
- 165:10-7-16.(d) details operating requirements for oil and gas exploration and production activity pits.
- 165:10-3-16.(e) details closure requirements for pits.
- 165:10-3-17 details further closure requirements, primarily the return of the surface conditions at the site of the pit to their original state, free of trash, debris, and equipment, within 90 days of the completion of well activities.

1.3.2.3 Pennsylvania

Regulations concerning technical requirements for oil field waste pits in Pennsylvania are found primarily in Pennsylvania Code, Title 25 (Environmental Protection), Part 1 (Department of Environmental Protection), Subpart C (Protection of Natural Resources), Article I (Land Resources), Chapter 78 (Oil and Gas Wells) and Chapter 91 (General Provisions). Additional language can be found in Pennsylvania (PA) Act 13 of 2012. Regulations relevant to this addendum include the following:

- PA Act 13 of 2012 §3215 prevents wells from being sited in any floodplain if the well is to employ a pit or impoundment or a tank managing solid wastes from oil and gas exploration and production.
- PA Act 13 of 2012 §3216 requires that a well site be restored following cessation of drilling operations. This includes restoration of the earthwork or soil disturbed, removal of all drilling supplies and equipment within nine months after completion of the drilling well, and compliance with all applicable requirements of the Clean Streams Law. The restoration period is subject to an extension if certain conditions are met.
- PA Act 13 of 2012 §78.56 details requirements for pits and tanks that are used to manage waste temporarily. Some requirements include a minimum of 2 ft of freeboard for pits or impoundments, structural soundness of pits and tanks, minimum liner requirements, and waste separations and prohibitions.
- PA Act 13 of 2012 §78.57 details requirements for management of production fluids, including collection of brine and other fluids from the well operations, requirements for pits, removal and disposal of fluids, and restoration of the waste management units or facilities following the closure or cessation of operations.
- PA Act 13 of 2012 §78.61 details the requirements for disposal of drill cuttings, including criteria to be met to allow for disposal in a pit, criteria to be met to allow for disposal by land application, other methods of disposal of drill cuttings, and compliance requirements for disposal.
- PA Act 13 of 2012 §78.64 details secondary containment criteria to be met for tanks used on drill sites, including required capacity and inspection requirements.
- PA Act 13 of 2012 §78.65 details site restoration requirements following the cessation of operations at a well site.

1.3.2.4 Texas

Regulations concerning technical requirements for solid waste management of oil and gas exploration, production, and development in Texas are found primarily in the Texas Administrative Code, Title 16, Part 1, Chapters 1–20. The Railroad Commission of Texas (RRC) is the primary authority in Texas regarding the regulation of oil and natural gas. Regulations relevant to this addendum include the following:

- Rule §3.3 details that all tanks must be clearly identified by signage at all times.
- Rule §3.5 details that a permit is required, issued by the RRC, in order to drill, deepen, plug back, or reenter any oil, gas, or geothermal resource well. The rule does not include any required specifications for waste management in the permit.
- Rule §3.8 defines the various types and functions of pits that are to be found in the regulations. Additionally, the rule defines oil and gas waste. The rule sets forth~~defines~~ what types of pits are prohibited, including for the storage of oil products, the requirement to obtain a permit for constructing and operating a pit, authorized disposal

methods, liner requirements, minimum freeboard ~~provisions~~, ~~steps to ensure~~ prevention of run-on from stormwater, ~~and procedures for the~~ draining of pits and inspection of pit liners. ~~In addition, t~~The Rule details instances in which a pit may be used without a permit, including as a reserve pit, completion pit, or basic sediment pit. The Rule also notes that the pit operator must keep records detailing that the pit liner requirements are met.

- Rule §3.15 details the requirements for the removal of all surface equipment from inactive wells, including the removal of all tanks or tank batteries.
- Rule §3.22 details the requirements of screening or netting of pits to protect wildlife, specifically birds.
- Rule §3.57 details the requirements for reclaiming tank bottoms and disposal of other EDP wastes. This includes the requirement for a permit, the use of a reclamation plant, and other miscellaneous requirements.
- Rule §3.78 details financial assurances and fees required ~~in order~~ to commence drilling activities. These financial assurances include bonding requirements for varying operations and number of wells.
- Rule §4.620 prohibits the disposal of naturally occurring radioactive material (NORM) waste by burying it or applying it with the land surface without obtaining a permit. The section details that the disposal of NORM waste is subject to Rule §3.8.

Commented [EK62]: NETL Team - please edit this awkward phrasing. It seems to suggest NORM may be 'applied' with the land surface. Just not sure what the writer here means precisely.

1.3.2.5 West Virginia

Commented [ST63]: No air regs in WV?

Commented [HSAJ64R63]: Do they just cover VOCs or Methane & Co2?

The following are oil and natural gas solid waste regulations for the state of West Virginia (WV):

- WV Code Chapter 22 Art. 6 Section 7, Chapter 22 Art. 11 Section 1–27, and Chapter 22 Art. 6 details permitting requirements and authority.
- WV Code Chapter 22 Article 6 Section 7 details waste pit authority of the general permit.
- WV Code Chapter 22 Series 6A contains the Horizontal Well Control Act.
- WV Code Title 35 Series 8 details horizontal well permits regarding the requirements and handling of waste cuttings.

Additionally, documentation that dictates surface and groundwater pollution prevention requirements for WV include the following:

- General Water Pollution Control Permit
- Erosion and Sediment Control Field Manual
- 35-8 Rules Horizontal Well Development
- 35-1 Water Pollution Control Rule

Below is a summary of some relevant sections of the WV code regarding oil and natural gas solid waste regulations relevant to this Addendum:

- §35-1-7 details requirements for dikes, berms, and retaining walls at oil and gas operations, requirements for secondary containment of tanks or tank systems, and other associated mechanical operational requirements.
- §35-4-16 details design and operation criteria for pits and impoundments.
- §35-4-21 describes design and construction requirements for pits and impoundments with a capacity greater than 5,000 barrels, including inspections.
- §35-2-3 requires that a permit be obtained by the Division of Environmental Protection, Office of Oil and Gas prior to the commencement of ~~any~~ solid waste management efforts ~~facilities~~ at the ~~site of~~ oil and gas exploration and production site.
- §35-4-10 details financial assurance requirements for oil and gas exploration and production activities, including the demonstration of financial responsibility of individual and grouped wells, coincidence with permit application for financial assurance, and the varying forms of financial assurance allowable.
- §35-8-5 details requirements for permits, notice, and review of horizontal wells, including siting restrictions, financial assurance for horizontal wells, and permitting requirements.

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2 Greenhouse Gas Emissions and Climate Change

CH_4 and CO_2 emissions from the LNG life cycle ~~and natural gas end uses~~ vary widely across different regions and supply chains. This section presents a review of contemporary (2014 and after) life cycle analysis (LCA) as it pertains to LNG and natural gas GHG emissions.

2.1 Introduction

To account for all sources of GHG emissions in the natural gas supply chain, and to evaluate their relative contributions and mitigation opportunities, a systems-level perspective is both necessary and preferred. LCA is one type of systems approach available to account for the different sources of GHG emissions in the natural gas supply chain. LCA specifically considers the material and energy flows of an entire system, ~~-~~"from cradle to grave~~.~~," ~~W~~where ~~the~~ "cradle" refers to the extraction of resources from the earth, and ~~the~~ "grave" refers to the final use and disposition of all products.

Depending on the type of LCA conducted, different system boundaries can be put in place to more accurately estimate the GHG emissions associated with natural gas. Generally, GHG emissions occur from the beginning of the natural gas supply chain (during exploration) through the end (during utilization). In some cases, an LCA may not consider every step of the natural gas supply chain within its analysis framework. This can happen for a variety of reasons, including lack of emission data for a particular step or set of steps, or simply to focus specifically on the emissions associated with one particular ~~part~~ step. Exhibit 2-1 provides an illustration of the natural gas supply chain with examples of key emissions sources (Balcombe et al, 2016).

Exhibit 2-1. Natural gas supply chain with examples of key emission sources

Permission pending from Balcombe et al. (2016)

Commented [TS65]: This diagram is missing a few steps.

Gathering and Boosting

Piped Transmission and Storage between "Processing" and "Liquefaction".

Is there a more accurate diagram that better aligns with the NETL or EPA GHGRP or GHGI categories and emission sources?

Commented [HSAJ66R65]: Create custom NETL graphic.

There are two primary approaches used to conduct natural gas LCA: 1) top-down and 2) bottom~~s~~-up (Rutherford et al., 2021; Alvarez et al., 2018; Balcombe et al., 2016). A top-down approach ~~1~~a) measures the atmospheric concentrations of CH_4 as reported by fixed ground monitors, mobile ground monitors, aircraft, and/or satellite monitoring platforms; ~~2~~b) aggregates the results to estimate total CH_4 emissions; and ~~3~~c) allocates a portion of these total emissions to each of the different supply chain activities. A bottom~~s~~-up approach measures ~~CH_4~~ GHG emissions directly from each source of emissions, then aggregates and extrapolates these measurements to estimate emissions for an entire region or process. Both approaches have ~~their~~ advantages and disadvantages.

For example, several studies (Rutherford et al., 2021; Alvarez et al., 2018; Balcombe et al., 2016) have noted that top-down approaches may lead to a general upward bias in emissions reporting while bottoms-up approaches may lead to a general downward bias in emissions reporting. There are several factors that may lead to these biases, which can be generally explained as follows:

- Top-down approaches sometimes fail to distinguish between different sectors. For example, aircraft that are used to collect emissions data for a particular area may struggle to distinguish between the CH_4 emissions coming from a natural gas processing facility in the area from those coming from a near-by dairy farm. This can lead to incorrect contributions of total CH_4 emissions to specific natural gas activities.
- Bottom~~s~~-up measurements sometimes fail to capture "super emitters"—a small number of facilities (or types of equipment) ~~who~~ that emit disproportionately large quantities of emissions. Because bottom~~s~~-up approaches measure emissions from individual sources and because super emitters, by definition, represent only a small proportion of the total number of facilities (or equipment) represented within the natural gas supply chain, it can be challenging to accurately capture the contributions of ~~a~~ super emitter activity to total emissions.

Alvarez et al. (2018) also notes that in many bottom~~s~~-up approaches to modeling, operator cooperation is required to obtain site access for accurate emissions measurements. Operators with lower-emitting sites are plausibly more likely to cooperate with ~~the conduct of~~ such studies and workers are plausibly more likely to be careful to avoid errors or fix problems when measurement teams are on site or about to arrive, which could lead to a downward bias in estimates of potential emissions (Rutherford et al., 2021; Alvarez et al., 2018; Balcombe et al., 2016).

Another key difference in LCA methodology or assumptions that can lead to differences in LCA outputs (i.e., estimates of emissions) is ~~tied to the choice of~~ which climate-forcing impacts of CH_4 ~~are~~ is used (Balcombe et al., 2016). CH_4 emissions have a large short-term ~~and~~ climate-forcing impact[f] compared to CO_2. The instantaneous forcing impact of CH_4 is around 120 times that of CO_2 ~~on a~~ for an equivalent amount of mass ~~basis~~. CH_4, however, only has an average

[f] Climate or radiative forcing, a measure, is defined by the Intergovernmental Panel on Climate Change (IPCC) as the influence a given climatic factor has on the amount of downward-directed radiant energy impinging upon Earth's surface.

Commented [LBD67]: GHG emissions? Not only CH4, correct? In this section generally, sometimes reference is made to CH4 monitoring/detection - suggest some explanation of when only CH4 is measured and when all GHGs are considered.

Commented [HSAJ68R67]: Make distinction between just CH4 and GHG more clear.

Commented [TS69]: This needs to be balanced with the understanding that in the 12 year the radiative forcing is changing. I can not find a reference to support the 120 times? Is this in watts/meter perspective?

Recommend we stay with IPCC 100 yr and 20 year perspective of difference in radiative forcing.

The temporal period of how long the pollutant stays in the atmosphere is critical to understanding its relative radiative forcing when compared to other GHGs, CO2. Remove or provide the complete story.

Commented [HSAJ70R69]: Take this out.

lifespan of 12 years in the atmosphere, after which it oxidizes into CO_2. CO_2 emissions remain in the atmosphere for much longer—25 percent of CO_2 emissions ~~still exists~~remain in the ~~atmosphere~~atmosphere ~~after~~ 1,000 years after emission (Balcombe et al., 2016). Consequently, while the climate-forcing impact of CH_4 emissions changes significantly over time, the impact of CO_2 emissions remains ~~much more~~ constant for a longer time.

Commented [TS71]: CO2 also declines over time, not constant. The temporal period is just longer. You confirm my point in the previous sentence.

This paragraph is misleading because it is not telling the complete story. A radiative forcing decay graphic showing a single pulse of emissions at time = zero is needed to tell the complete story.

Alternatively, this paragraph. I would keep the first two sentences and use them as the start of the next paragraph on GWP.

Typically, studies use global warming potential (GWP) to compare the climate impact of emissions of different GHGs such as CH_4 with CO_2. The GWP is defined as a measure of how much energy the emissions of 1 ton of a gas will absorb over a given period, relative to the emissions of 1 ton of CO_2 (Balcombe et al., 2016). The IPCC progressively raised the GWP for CH_4 to 28 over a 100-year period and 84 over a 20-year period in their Fifth Assessment Report (AR5) published in 2014 (Stern, 2022). IPCC's Sixth Assessment Report (published in 2021) raised the GWP of CH_4 to 29.8 over a 100-year horizon but reduced the 20-year horizon factor to 82 (Stern, 2022). Adding climate feedback mechanisms and oxidation, these figures were increased to 36 and 87.15, respectively in the IPCC's Sixth Assessment Report.

To illustrate, if the GWP of CH_4 for a time horizon of 100 years is 36, this means that a pulse emission of CH_4 absorbs 36 times more energy than CO_2 over 100 years, on average. Note that the GWP of CH_4 for a time horizon of 100 years does not give any information on the climate forcing of CH_4 at the end of the 100 years; it gives only the average impact across the 100 years. ~~Additionally, the use of a single value to compare GHGs does not consider the changing impacts over time.~~ It is important to consider ~~the~~ which GWP is used when analyzing the outputs of an LCA, particularly when comparing the outputs of two or more LCAs (Balcombe et al., 2016).

2.2 Federally-Funded LCA

NETL has used LCA to calculate the environmental impacts of natural gas production and use for the generation of electric power for nearly a decade (NETL, 2023). Their work has been documented in a series of reports produced between 2010 and 2019.[g] Together, these reports provide in-depth assessments of the potential GHG emissions resulting from unconventional natural gas production in the United States. The GHG emissions results recorded in the NETL 2019 report considers five stages of the natural gas supply chain, which are visualized in Exhibit 2-2 (NETL, 2019):

Commented [TS72]: Need to mention the LNG work at the beginning and discuss that the LNG report builds upon the NELT upstream natural gas report by adding liquefaction, ocean transport, regasification, distribution and end use of the gas in a large scale power plant.

This will help create synergies to the Exhibit 2-1 description of the natural gas and LNG system boundary.

For Exhibit 2-1, you may want to create your own graphic.

1. **Production:** Sources of emissions include the gas vented from pneumatically controlled devices and fugitive emissions from flanges, connectors, open-ended lines, and valves. When vapor recovery units are feasible, vented gas is captured and flared; otherwise, vented gas is released to the atmosphere. Production operations also include the combustion of natural gas and diesel in compressors and other equipment.
2. **Gathering and Boosting (G&B):** Natural gas G&B networks receive natural gas from multiple wells and transport it to multiple facilities. G&B sites include acid gas removal, dehydration, compressors operations, pneumatic devices, and pumps.

[g] The GHG results in the NETL (2019) report supersede the GHG results in the previous NETL reports.

3. **Processing:** A natural gas processing facility removes impurities from natural gas, which improves its heating value and prepares it for pipeline transmission. Natural gas processing facilities include acid gas removal, dehydration, hydrocarbon liquids removal, and compression operations.

4. **Transmission Stations, Storage Facilities, and Transmission Pipelines:** A natural gas transmission system is a network of large pipelines that transport natural gas from processing facilities to the city gate (the point at which natural gas can be consumed by large-scale consumers or transferred to local distribution companies). Transmission stations are located along natural gas transmission pipelines and use compressors to boost the pressure of the natural gas.

5. **Distribution:** Natural gas distribution networks transport natural gas from the city gate to commercial, residential, and some industrial consumers. This analysis uses the distribution portion of the supply chain only for the upstream functional unit; distribution is not necessary for the functional unit of electricity in which natural gas power plants receive natural gas directly from transmission pipelines.

Exhibit 2-2. Supply chain stages that compose the overall LCA boundary

Commented [TS73]: Need higher quality image and to cite image source.

Commented [HSAJ74R73]: Could give its own page to sharpen

The flexible, consistent framework of NETL's LCA model allows different natural gas sources to be compared on a common basis (per megajoule [MJ] of delivered natural gas). In the NETL (2019) report, five types of natural gas are considered:

1. **Conventional natural gas** is natural gas extracted via vertical wells in high permeability formations that do not require stimulation technologies for primary production.

2. **CBM** is extracted from coal seams and requires the removal of naturally occurring water from the seam before natural gas wells are productive.

3. **Shale gas** is extracted from low permeability formations and requires hydraulic fracturing and horizontal drilling.

4. **Tight gas** is extracted from non-shale, low permeability formations and requires hydraulic fracturing and directional drilling.

5. **Associated gas** is found with petroleum (either dissolved in oil or in a gas cap in a petroleum formation) and is produced by oil wells.

EPA estimates oil and natural gas CH_4 emissions in the annual Greenhouse Gas Inventory (GHGI) it produces. The GHGI uses a bottom~~s~~-up approach to estimate national CH_4 emissions.

In its 2019 LCA analysis of the natural gas supply chain, NETL used the GWP reported in the IPCC AR5. Other key input data was sourced from EPA's GHGI, Drilling Info (DI Desktop), and EIA. Results from the 2019 NETL LCA analysis performed suggested the following:

- The life cycle GHG emissions associated with the U.S. natural gas supply chain were 19.9 grams (g) of carbon dioxide equivalents (CO_2e) per MJ of natural gas delivered (with a 95% mean confidence interval of 13.1–28.7 g CO_2e per MJ).
- The top contributors to CO_2 and CH_4 emissions were combustion exhaust and other venting from compressor systems. Compressor systems are prevalent in most stages of the natural gas supply chain and as such were key contributors to the total life cycle emissions estimated.
- Emission rates ~~were~~ are highly variable across the entire supply chain. According to the study (NETL, 2019), the national average CH_4 emissions rate was 1.24 percent, with a 95 percent mean confidence interval ranging 0.84–1.76 percent.

Exhibit 2-3 shows the upstream GHG emissions from the different parts of the natural gas supply chain. The blue bars represent CO_2 emissions, the green bars represent CH_4 emissions, and the orange bars represent nitrous oxide (N_2O) emissions. The vertical black lines in Exhibit 2-3 and Exhibit 2-4 represent the error bars in this analysis, and the shaded grey area represents the 95 percent mean confidence interval.

Commented [TS75]: Add citation

Commented [TS76]: Add GHGRP (this is the primary data source, not GHGI)

Commented [LBD77]: Suggest citing somehow that Exhibits 2-3 and 2-4 are from the referenced NETL 2019 report.

Exhibit 2-3. Life cycle CH_4 emissions from the U.S. natural gas supply chain

Commented [LBD78]: Figure would benefit from a legend or explanation of the different elements.

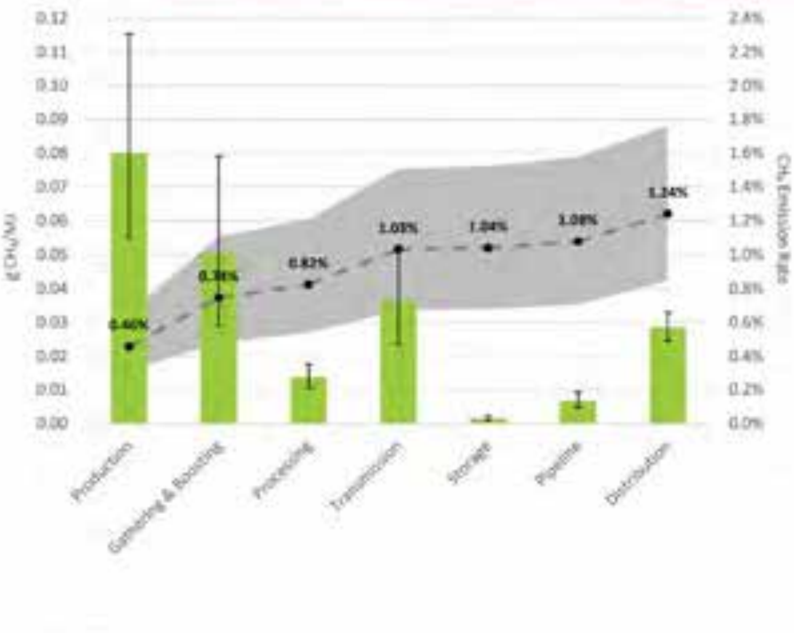
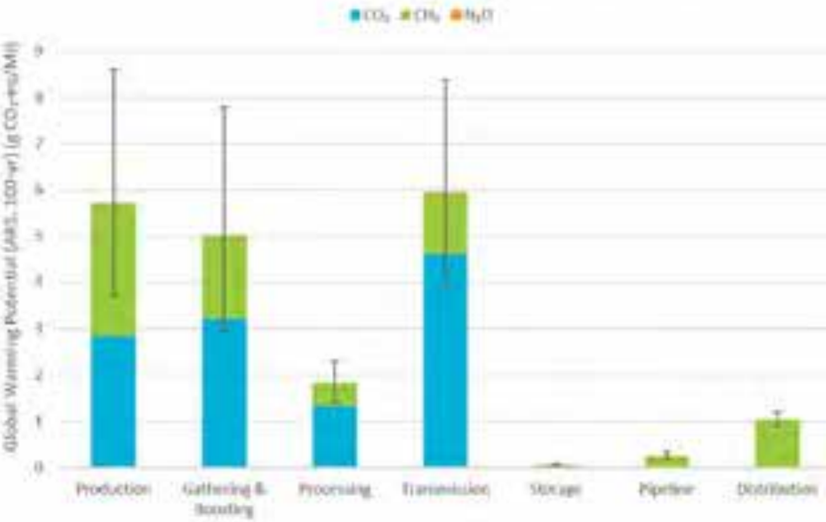


Exhibit 2-4. Life cycle GHG emissions for the U.S. natural gas supply chain



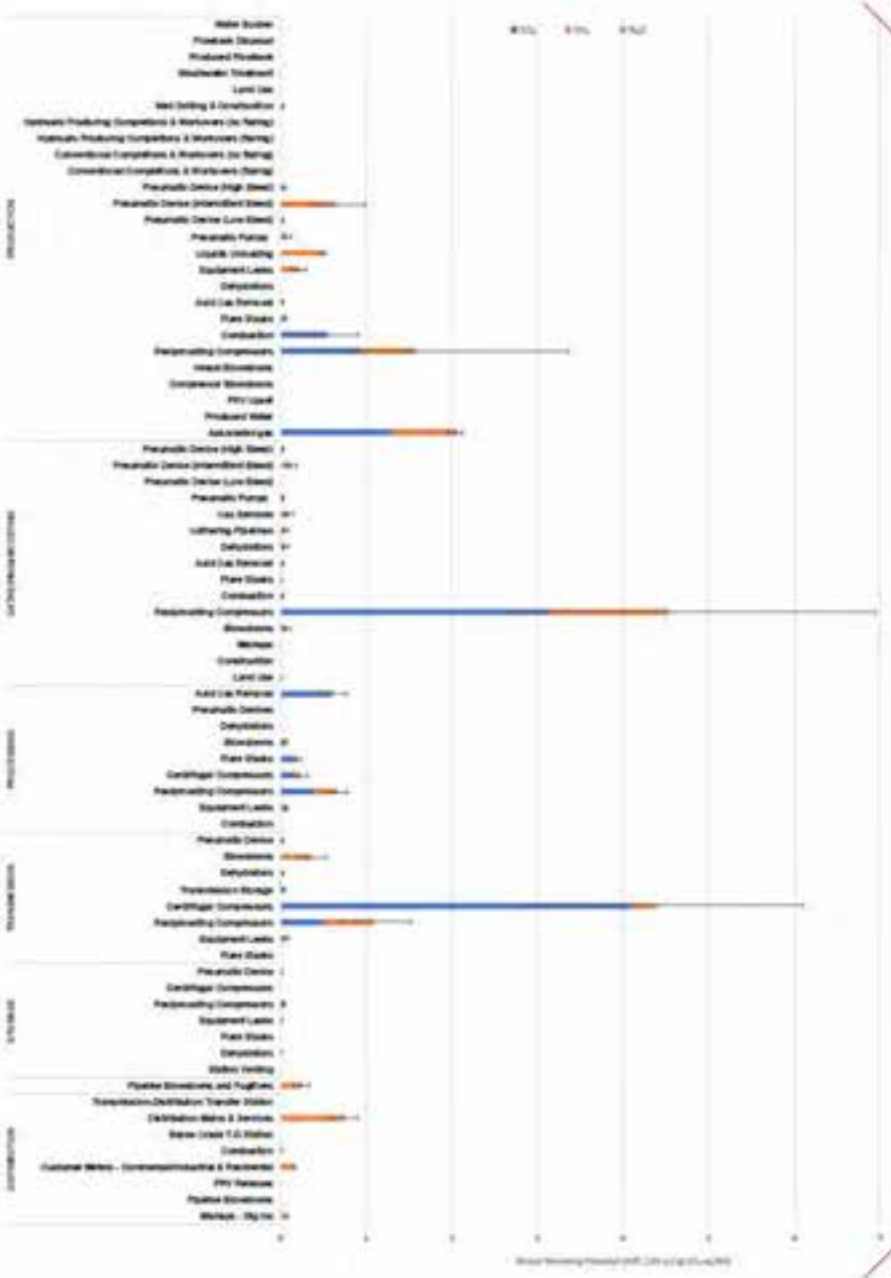
Key drivers of GHG emissions results for the entire natural gas supply chain are illustrated in Exhibit 2-5 (NETL, 2019). Pneumatic devices and compression systems represent a significant portion of the total life cycle GHG emissions associated with the natural gas supply chain (NETL, 2019). Pneumatic devices are used to operate level controllers, valves, and other equipment at natural gas facilities. According to EPA's GHGI, production pneumatics emitted 1,060 kilotons of CH_4 in 2017, accounting for 16 percent of the total CH_4 emissions from the natural gas supply chain. Pneumatic device activity is concentrated at production facilities and there were 833,000 pneumatic devices used by U.S. production facilities in 2019 (NETL, 2019).

Natural gas is compressed for transport from processing facilities to end-consumers. As such, upstream GHG emissions are sensitive to pipeline distances and the number of compressors along these pipelines that the natural gas must pass through. The energy intensity of compression and the fugitive CH_4 emissions from compressors both contribute to upstream GHG emissions (NETL, 2019).

In addition to being a source of CH_4 emissions, compressors are also a source of CO_2 emissions. Most compressors in the U.S. pipeline transmission network are powered by natural gas that is withdrawn from the pipeline itself. Electric motors are not widely used by natural gas pipelines but are installed where local emission regulations limit the use of internal combustion engines or where inexpensive electricity is available. Approximately three percent of compressors used by the natural gas transmission network are electrically driven.

Commented [TS79]: Cite source.

Exhibit 2-5. Detailed GHG emission sources for the U.S. natural gas supply chain

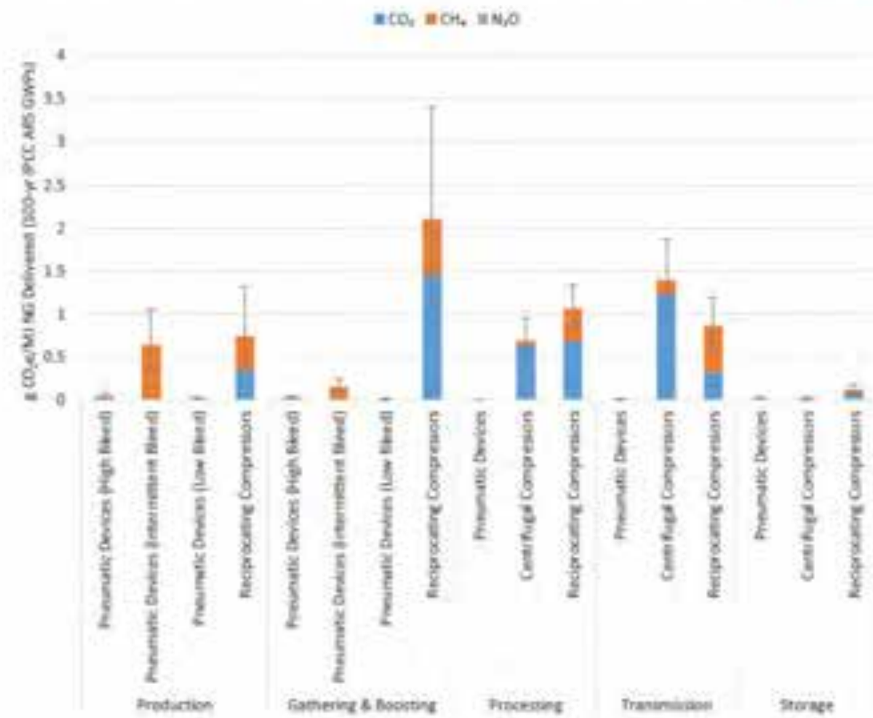


Commented [TS80]: State what year the data represents in the caption and what scope? US average for transmission and distribution combined?

Commented [TS81]: Need higher resolution image.

Two sources of CH_4 emissions from compressor systems include 1) CH_4 that slips through the compressor uncombusted~~ion~~ into the exhaust stream and 2) CH_4 that escapes through compressor seals or packing. Natural gas systems use both centrifugal and reciprocating compressors. Centrifugal compressors are more appropriate for pressure boosting applications in steady-state applications (such as a transmission pipeline), while reciprocating compressors are more appropriate when gas flow is variable and when large increases in pressure are required. Centrifugal compressors are typically driven by gas-fired turbines but, in some instances, are driven by an electric motor. Reciprocating compressors are driven by gas-fueled engines. Exhibit 2-6 illustrates the emissions associated with pneumatic devices and compressors.

Exhibit 2-6. GHG emissions from pneumatic devices and compressors across the NG supply chain



For all natural gas production types, the GHG emissions results produced by an LCA are sensitive to production rates and episodic emissions (either liquid unloading or workovers).

Commented [LBD82]: "slips through the compressor uncombusted into the exhaust stream"?

Commented [TS83R82]: Yes.

Commented [TS84]: Exhibit 2-5 and 2-6 units, while the same, are described differently. Exhibit 2-5 is the general standard with the exception of carbon dioxide equivalents are ported as CO2e (subscripted 2) and not as CO2-eq in Exhibit 2.5.

Commented [TS85]: The data does not support this statement. Liquids Unloading is 0.5 g CO2e (Exhibit 2-5)per the life cycle total of 19.9 with a mean uncertainty range of 13.1 to 28.7. The variance in liquids unloading is well within the mean uncertainty range and therefore not a sensitive parameter.

Exhibit 6-8 in the NETL 2019 report provides a ranking of GHG emissions uncertainty (not model sensitivity) but does indicate which sources contribute have an influence on the accuracy of the results.

Results are sensitive to:

- •EUR
- •Regional natural gas composition differences (dry versus sour gas).
- •Compression energy requirements and type.
- •Pneumatic device type, frequency, and number of devices per operation.
- •Episodic events that result in higher (than normal operations) methane emissions over a short time frame (not a consistent emission source) originating from maintenance and inspection activities or non-standard operator practices.

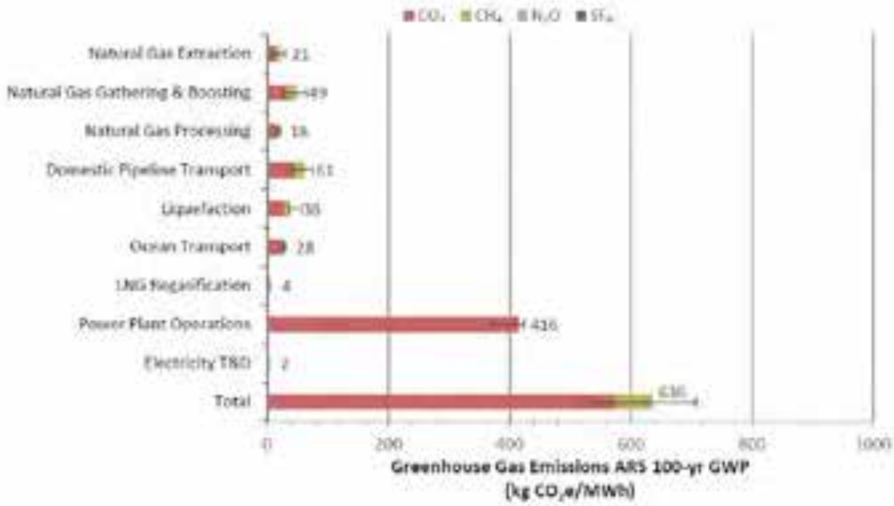
The above bullet provides a more generic way of describing episodic emissions. My concern was calling out specifically liquids unloading and workovers.

Commented [HSAJ86R85]: Adjust sentence to reflect list provided above.

In addition to its characterization of domestic upstream natural gas, NETL also developed life cycle data for exported LNG, including the GHG emissions from liquefaction, transport, regasification, and ~~the~~ combustion for electricity generation (NETL, 2019).

The NETL (2019) report that analyzed the lifecycle emissions of exporting U.S. LNG to Europe yielded the emissions results (assuming end-use in electricity generation) detailed in Exhibit 2-7.

Exhibit 2-7. GHG emissions from exporting LNG from the United States to Europe



Littlefield, Rai, and Skone (2022) show that geography matters in terms of the GHG emissions estimated for the global natural gas supply chain~~,~~ – where natural gas is produced and ultimately used plays a tremendous role in the total amount of GHG emissions estimated for the supply chain. ~~As such~~Accordingly, a national average value is not necessarily an adequate representation of an individual (source to sink) natural gas supply chain. Littlefield, Rai, and Skone (2022) provide a detailed life cycle perspective on GHG emissions variability where natural gas is produced and where it is delivered. They disaggregate transmission and distribution infrastructure into six regions, balance natural gas supply and demand locations to infer the likely pathways between production and delivery (estimated via modeling as actual tracking of natural gas from well to customer is not technically feasible), and incorporate new data on distribution meters. They find the average transmission distance for U.S. natural gas is 815 kilometers (km) but ranges 45–3,000 km across estimated production-to-delivery pairings examined (Littlefield, Rai, and Skone, 2022). In terms of total GHG emissions, their results suggest the delivery of 1 MJ of natural gas to the Pacific region has the highest mean life cycle GHG emissions (13.0 g CO_2e/MJ) and the delivery of natural gas to the Northeastern region of the United States has the lowest mean life cycle GHG emissions (8.1 g CO_2e/MJ).

Commented [LBD87]: Is this a separate NETL 2019 report? Or the same one as above? If the same, suggest citing it in full on first mention.

Commented [TS88R87]: Yes a different report.

Commented [LBD89]: Suggest somewhere a comment be made that the supply chain study presented above is "cradle to gate," and excludes end-use, while the LNG study is more truly "cradle to grave," and does include end-use (power generation), meaning extra care should be taken by readers in comparing results and figures.

Commented [TS90]: This report does not discuss global natural gas supply sources?

I think you mean US.

Commented [LBD91]: How does this compare with other analyses we rely on? Do we rely on national averages elsewhere

In 2020, NETL collaborated with industry and published an analysis of Our Nation's Energy Future's (ONE Future) portfolio of assets (Rai et al., 2020). ONE Future is a natural gas industry partnership dedicated to improving the efficiency of the domestic natural gas supply chain. ONE Future represents 1–13 percent of total throughput in the respective segments of the natural gas industry supply chain. The expected life cycle CH_4 emission rate for ONE Future average natural gas is 0.76 percent (with a 95 percent mean confidence interval ranging 0.49–1.08 percent).

The expected life cycle CH_4 emission rate for the U.S. average scenario is 1.06 percent. In terms of IPCC 100-year GWP, the ONE Future and U.S. average scenarios emit 9.7 and 14.1 g CO_2e/MJ of delivered natural gas, respectively.

2.3 Other Natural Gas Analyses

Balcombe et al. (2016) document the wide range of CH_4 emissions estimates across the natural gas supply chain. Estimates of combined CH_4 and CO_2 emissions range 2–42 g CO_2e/MJ. A ~~s~~Significant drivers of this wide range of projections are 1) the emissions associated with upstream natural gas production, and 2) whether the natural gas is ultimately converted to LNG or not. This sub-section explores these different segments of the supply chain.

2.3.1 Natural Gas Production Analyses

Several studies have found that CH_4 emissions from the natural supply chain are about 1.5–2.5 times the amount reported in EPA's GHGI (Rutherford et al., 2021; Alvarez et al., 2018; Balcombe et al., 2016). Much of the discrepancy can be attributed to differences in the analyses performed for the production segment of the natural gas supply chain where super emitters and emissions-intensive equipment are both prevalent (Rutherford et al., 2021; Alvarez et al., 2018; Balcombe et al., 2016).

To isolate specific sources of disagreement between EPA's GHGI and other studies, Rutherford et al. (2021) reconstruct EPA's GHGI emission factors, beginning with the underlying datasets, and uncover some possible sources of disagreement between inventory methods and top-down studies. The adjusted emissions factors are direct inputs in the Rutherford et al. (2021) study outputs. Rutherford et al. use~~s~~ a bottom~~s~~-up measurement approach, yet the approach differs from the GHGI in that it applies a bootstrap resampling statistical approach to allow for inclusion of infrequent, large emitters, the analysis robustly addressing the issue of super-emitters in a more robust way.

Rutherford et al. (2021) estimate the mean, production-normalized emissions rate from the production segment as 1.3 percent (1.2–1.4 percent at 95 percent confidence interval, based on gross natural gas production of 32 Tcf and an average CH_4 content of 82 percent), slightly lower than Alvarez et al., 2018) who estimate it at 1.4 percent. Rutherford et al. (2021) estimate mean natural gas production-segment CH_4 emissions as equal to 6.6 teragrams (Tg) per year (6.1–7.1 Tg per year, at 95 percent confidence interval). Both the results of Rutherford et al. (2021) and Alvarez et al. (2018) are approximately two times larger ~~the~~ than estimates of the 2015 EPA

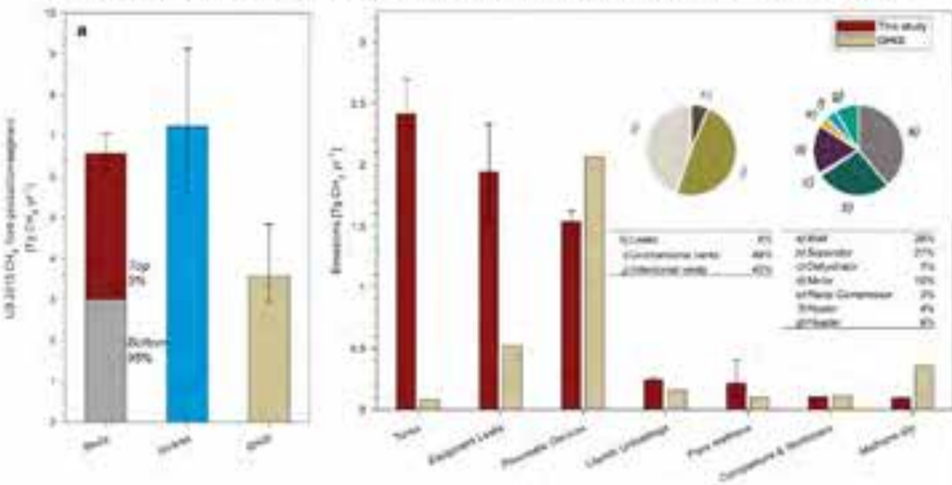
Commented [LBD92]: Comment applicable to other sections as well – is text being updated with more recent studies? (apologies if updating is ongoing in some sections and I'm not aware of it) Most or all of these studies (aside from NETL's) are >10 years old.

Commented [LBD93]: Comment applicable to other sections as well – is text being updated with more recent studies? (apologies if updating is ongoing in some sections and I'm not aware of it) Most or all of these studies (aside from NETL's) are >10 years old.

GHGI, which suggests that 3.6 Tg of emissions per year (year 2015 data, excludes offshore systems) come from the natural gas production segment.

Importantly, the difference in U.S. production-segment emissions estimates between the Rutherford et al. (2021) study and EPA's GHGI is approximately the same volume as Rutherford et al. (2021) study estimate of the contribution from super-emitters (top 5 percent of emissions events). Given that Rutherford et al. (2021) results match the Alvarez et al. (2018) site-level results, the former concludes that the divergence between the GHGI and top-down/site-level studies is not likely to be due to any inherent issue with the bottoms-up approach. A results comparison of the Rutherford et al. (2021) study, the Alvarez et al. (2018) study, and 2015 EPA GHGI data can be found illustration in Exhibit 2-8.

Exhibit 2-8. Comparison of GHG Emissions Results from Rutherford et al., Alvarez, et al., and EPA GHGI



Permission pending from Rutherford et al. (2021)

2.3.2 LNG Studies

Relative to traditional natural gas supply chains where pipelines are ~~primarily~~ the primary means by which natural gas is transported, LNG supply chains also involve liquefaction, shipping, and regasification stages ach of ~~which~~ these stages drive even greater variability in emissions profiles in LCA studies. A review of 37 global LNG supply scenarios between the United States and China by Gan et al. (2020) concluded that GHG emissions intensities varied by about 150 percent. Abrahams et al. (2015) note that emissions from the shipping of LNG exports from the United States to ports in Asian and European markets account for only 3.5–5.5 percent of precombustion life cycle emissions; hence, shipping distance is not a major driver of GHGs in the LNG supply chain.

At the end of 2020, Cheniere Energy was the largest exporter of LNG from the United States in terms of volume. Roman-White et al. (2021) developed an LCA framework to estimate GHG

Commented [TS94]: This sentence seems to conflict with the 2.5 times difference between Rutherford and EPA?

I am not sure I am interpreting your point correctly.

Also, what year does the data represent in the EPA GHGI to Rutherford comparison?

Commented [HSAJ95R94]: Revise sentence.

Commented [TS96]: If this is 2015 data, is this still a current perspective of the industry performance?

Does the latest EPA GHGI still result in this conclusion?

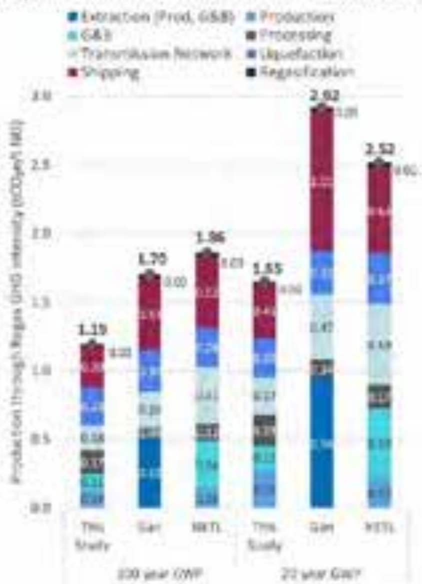
Commented [HSAJ97R96]: Is the comparison still accurate? If we cannot find a more contemporary comparison, should we make a statement on them? Suggest framing the discussion that updates have been made by EPA, etc. Adjust framing.. Softening context.

Commented [LBD98]: Comment applicable to other sections as well – is text being updated with more recent studies? (apologies if updating is ongoing in some sections and I'm not aware of it) Most or all of these studies (aside from NETL's) are >10 years old.

Commented [LBD99]: Does this mean +/- 150%? Or something else?

emissions representative of Cheniere's LNG supply chain, considering both upstream and downstream sources of emissions from Cheniere's Sabine Pass Liquefaction facility, using supplier-specific data collected from wellhead through ocean transport. Roman-White et al. (2021) compare the GHG emissions intensity of Cheniere LNG to two similar assessments of emission intensity from U.S. LNG transported to China (Gan et al., 2020; NETL, 2019). The results of their comparison are illustrated in Exhibit 2-9.

Exhibit 2-9. Comparison of GHG emissions results from Roman-White et al., Gan et al., and NETL



Used with permission from Roman-White et al. (2021)

The NETL (2019) LNG study uses more recent production emission data (2016 data) than Gan et al. (2020). The study is based on natural gas production in Appalachia with relatively low emissions intensity. The NETL analysis differs from the Roman-White et al. study primarily in the intensity of the G&B and transmission stages, which are driven by differences in individual facility performance.

Commented [LBD100]: Which study? Roman-White or NETL?

When modeling transmission compression, the NETL (2019) study assumes a factor of 0.97 horsepower-hour (HPh)/thousand cubic feet (Mcf) to estimate the transmission station throughput (derived from NETL-published parameters). The average ratio of HPh to Mcf of throughput, from Cheniere's known suppliers (used in the Roman-White et al. study) is 0.27 HPh/Mcf, which is based on supplier data collection completed. For modeling gas from other transmission operators, the GHGRP does not publicly provide the throughput of compressor stations. ~~As such, t~~The Roman-White et al. (2021) study assumes 0.29 HPh/Mcf based on data reported by EIA.

The higher factor used by the NETL (2019) study results in increased modeled fuel consumption across the transmission network. The Roman-White et al. liquefaction GHG intensity is 8–13 percent less than the intensity estimated by Gan et al. and is comparable to the NETL (2019) study estimate on a 100-year basis. The Roman-White et al. (2021) study concludes ocean transport stage emission intensity is 42–60 percent less than the transport emission intensity of Gan et al. (2020), and 35–42 percent less than that of the NETL (2019) study.

Jordaan et al. (2022) estimate~~s~~ ~~the~~ global average life cycle GHG emissions from the delivery of gas-fired electricity to be 645 gCO_2e per kilowatt hour (kWh) (334–1,389 gCO_2e per kWh), amounting to 3.6 gCO_2e yr−1 in 2017 (10 percent of energy-related emissions). This result is within range of the results obtained by Roman-White et al. (2021), who report life cycle GHG emissions of 524 gCO_2e kWh for electricity in China from LNG supplied by U.S. LNG exporter Cheniere, and 636 gCO_2e per kWh reported by NETL (2019).

Cai et al. (2017) assess GHG emissions of using compressed natural gas and LNG as transportation fuels by three heavy-duty natural gas vehicles types from a wells-to-wheels perspective. [illegible] Cai et al. [illegible] that natural gas vehicle wells-to-wheels GHG emissions are largely driven by the vehicle fuel efficiency, as well as CH_4 leakage rates of both the NG supply chain and vehicle end use; the study estimates wells-to-wheels GHG emissions of natural gas vehicles to be slightly higher than those of the diesel counterparts given the estimated wells-to-wheels CH_4 leakage.

Commented [LBD101]: This paragraph seems a little bit tacked-on. Consider adding context or possibly deleting.

2.4 Mitigation Measures

Commented [LBD102]: Consider adding an introductory sentence or paragraph with an overall statement about types of mitigation measures discussed in this section.

Commented [TS103R102]: Agree to delete this paragraph and replace with a concluding paragraph for Section 2.3. What is the takeaway message from all of these reports and data?

Commented [LD104R102]: Note to reviewers - I think Tim's response here goes with the comment above – regarding the current last para of section 2.3

Compressor seals include ~~the~~ wet seals used by ~~the~~ centrifugal compressors and ~~the~~ rod packing used by reciprocating compressors. Wet seals surround the rotating shaft of a centrifugal compressor with oil, which prevents gas leakage from the compressors. The oil used by wet seals must be continuously regenerated, which releases CH_4 into the atmosphere. By replacing wet seals with mechanical dry seals, the CH_4 emissions from centrifugal compressors can be reduced.

Reciprocating compressors prevent CH_4 leakage by encasing each compressor rod with a set of oil-coated, flexible rings. Proper maintenance and routine replacement of these rings prevents unnecessary leakage of CH_4. Storage tanks hold flowback water and liquid hydrocarbons recovered from the production stream. Variable loading levels and temperatures cause the venting of CH_4 and other gases from these tanks. By installing vapor recovery units on storage tanks, producers can more effectively reduce emissions from natural gas production. The captured emissions can be combusted on site to provide process energy, or they can be channeled to the sales stream.

Pneumatic controllers use gas pressure to open and close valves throughout a natural gas production and processing system. Natural gas is commonly used to pressurize pneumatic control systems. The bleeding of natural gas from pneumatic controllers leads to venting CH_4 to the atmosphere. The GHG impact of pneumatic control systems can be reduced by installing pneumatic systems that use pressurized air instead of pressurized natural gas.

Since ~~the~~ regulations focus on reduced emissions completions (RECs), they are more applicable to unconventional wells. RECs employ~~use~~ equipment that allow the capture of gas during flowback, either to be sent to the product line or, if this is not feasible, to be flared. However, ~~the~~ regulations also mandate emission reductions from pneumatically controlled valves and compressor seals, which are two types of emission sources common to conventional and unconventional natural gas technologies. Lastly, ~~F~~flowback emissions are governed by whether RECs are used or not.

The data suggest that the use of this equipment reduces completion emissions by approximately 75–99 percent. For the most established unconventional gas industry, the United States, the use of RECs is compulsory. However, once RECs are employed and CH_4 is flared to some degree, resultant CO_2 emissions from flaring may become significant (Balcombe, 2016).

A~~n~~ NETL (2020) report notes that compressed-air pneumatics are a mature technology that reduces CH_4 emissions from pneumatic systems. The technology replaces existing devices, which are actuated by natural gas, with devices that are actuated with compressed air. This requires the addition of electric-powered air compressors at natural gas facilities but can result in zero CH_4 emissions from pneumatics. A barrier to implementation of compressed-air pneumatics is electricity availability. The United States has an extensive electricity grid, but grid connections are not always near production sites. The same NETL (2020) report notes that proven technologies exist for reducing CH_4 emissions from compression systems (as described below):

- Centrifugal compressors emissions can be reduced by replacing wet seals with dry seals. These seals are used around the rotating shaft of the compressor and prevent high pressure gas from escaping the compressor. Wet seals involve the use of recirculating oil that emits 40–200 standard cubic feet (scf) of natural gas per minute (min). Dry seals use gas to seal the compressor shaft and emit only 6 scf/min. The replacement of wet seals with dry seals reduces centrifugal compressor emissions by 85–97 percent.

- Reciprocating compressor emissions can be reduced by replacement of rod packing. Packing prevents gas from moving around piston rods and escaping the compression cylinder. New packing that is properly installed on a well-maintained compressor will emit about 12 scf/hour. The emission rate for old or poorly installed packing can range 25–67 scf/hour. When compared to the emission rate for new packing, this equates to potential emission reductions of 52–82 percent. Rod packing replacement is a mature technology, but there are new technologies that can also reduce reciprocating engine exhaust slip. These new technologies include advanced materials that increase piston rod service life while reducing rod wear and Teflon-coated rings that reduce friction while maintaining a tight seal. There are no data currently available, however, on the emission reduction potential tied to deploying~~s of~~ these new technologies.

- The majority of the CH_4 emissions from reciprocating compressors are due to the CH_4 slip from engine exhaust. Comparing the exhaust emission factors for rich burn and lean burn engines, respectively, shows that [illegible] burn engines have a combustion effectiveness of 97 percent and lean burn engines have combustion effectiveness of 99

Commented [LBD105]: Which regulations? Suggest explain why they are being mentioned here.

Commented [LBD106]: It may be confusing that this is the name of "equipment." Suggest a little explanation if possible.

Commented [TS107]: RECs are required by law now this not a current issue for the industry. The point that REC implementation has shifted the emissions from methane to CO2 has occurred and did reduce GHG intensity form a global warming perspective.

Commented [HSAJ108R107]: Make clear its mandatory.

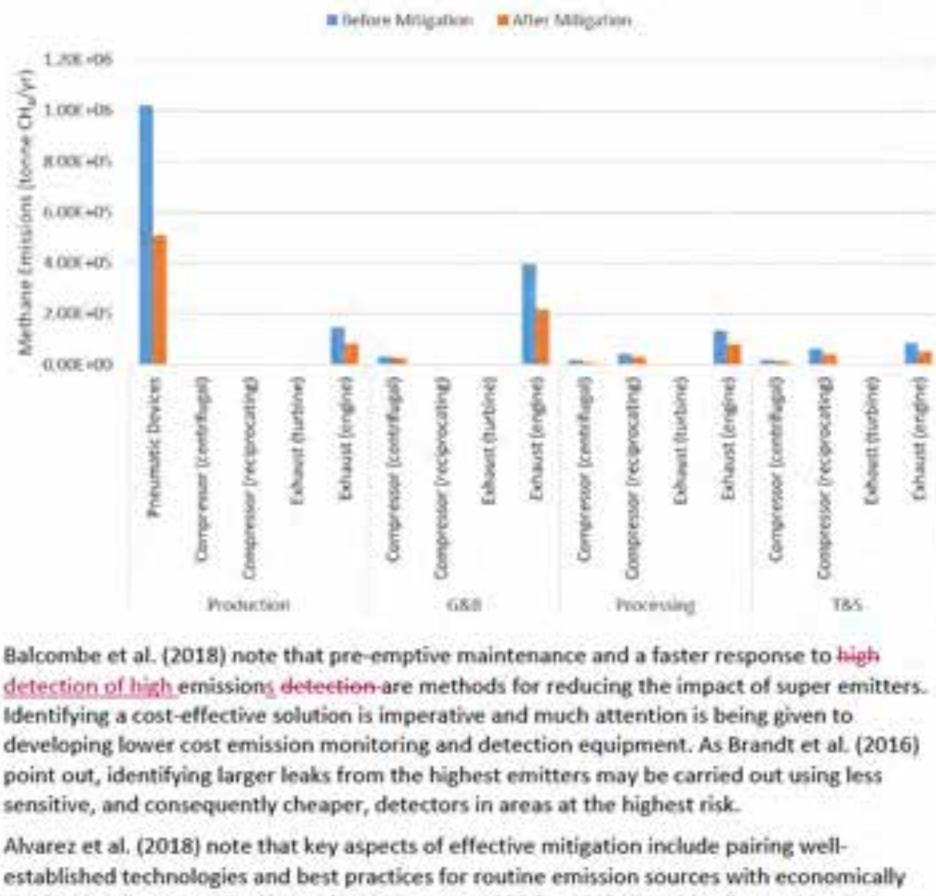
Commented [EK109]: NETL Team - with this proposed text correction, is the statement now accurate?

percent. Air-fuel-ratio controls are an option for improving the combustion effectiveness of lean burn engines while keeping NOx emissions low. More research is required to understand the limits of air-fuel-ratio controls but, for this analysis, it is assumed that they can increase the combustion effectiveness of a lean burn engine by 97–99 percent.

Exhibit 2-10 illustrates the impact of these mitigation approaches.

Exhibit 2-10. Illustration of mitigation measure impact for pneumatic devices and compressors

Commented [TS110]: What is the source? It this the ONE Future report. It was limited to the ONE Futures value chain and not the US average.



Balcombe et al. (2018) note that pre-emptive maintenance and a faster response to ~~high~~ detection of high emissions, ~~detection~~ are methods for reducing the impact of super emitters. Identifying a cost-effective solution is imperative and much attention is being given to developing lower cost emission monitoring and detection equipment. As Brandt et al. (2016) point out, identifying larger leaks from the highest emitters may be carried out using less sensitive, and consequently cheaper, detectors in areas at the highest risk.

Alvarez et al. (2018) note that key aspects of effective mitigation include pairing well-established technologies and best practices for routine emission sources with economically viable systems to rapidly detect the root causes of high emissions arising from abnormal conditions. The latter could involve combinations of current technologies, such as on-site leak surveys by company personnel using optical gas imaging, deployment of passive sensors at individual facilities or mounted on ground-based work trucks, and in situ remote-sensing approaches using tower networks, aircraft, or satellites. Over time, the development of less failure-prone systems would be expected through repeated observation of and further research into common causes of abnormal emissions, followed by reengineered design of individual components and processes.

With respect to liquefaction, Mokhatab et al. (2014) note that most of the plant energy consumption and resultant emissions in natural gas liquefaction facilities occur in the compressor drivers, where fuel energy (usually natural gas) is converted to mechanical work (or electricity in case of electrically driven compressors). Due to the energy consumption scale of the LNG plants, any enhancement to the energy efficiency of a plant will result in a significant reduction in gas consumption and consequently CO_2 emissions (Mokhatab et al., 2014).

There are two ways to increase the energy efficiency of LNG plants: 1) liquefaction cycle enhancement and 2) driver cycle enhancement. Liquefaction cycle enhancements reduce ~~the~~ compressor power and consequently the compressor driver's fuel consumption. Driver cycle enhancement reduces the amount of fuel consumption to generate a specific amount of power. Typical fuel sources for natural gas liquefaction cycles include either pure refrigerant in cascade cycles, expansion-based cycles, or mixed refrigerant cycles.

Pure refrigerant cycles have a constant evaporating temperature that is a function of the saturation pressure. Mixed refrigerant cycles do not maintain a constant evaporating temperature at a given pressure. Their evaporating temperature can range and change depending on the pressure and composition. A refrigerant mixture of hydrocarbons and nitrogen is chosen so that it has an evaporation curve that matches the cooling curve of the natural gas with the minimum temperature difference. ~~As such~~Therefore, small temperature differences reduce entropy generation, and, thus, improve thermodynamic efficiency, reduce power consumption, and reduce the emissions associated with liquefaction facilities (Mokhatab et al., 2014).

A study from Pospišil et al. (2019) notes that a certain part of the energy spent on liquefaction can be recovered by the utilization of cold stream from LNG. The amount of usable cold is given by thermophysical properties of natural gas and corresponds to 830 kilojoule (kJ)/kg of LNG. This cold energy can be recovered during the regasification process. Regasification is carried out either in port terminals before natural gas is transported via gas lines or directly before the use of natural gas. The exploitation of cold from LNG is quite limited at present. Most of the available cold is wasted during the regasification process when LNG is heated up by water or ambient air. Inefficient use of cold temperature streams reduces the overall efficiency of this primary energy source and leads to greater emissions. Promising ways of utilizing cold from LNG in the regasification process should be explored and implemented (Pospišil et al., 2019). For LNG that is ultimately combusted for electricity, Jordaan et al. (2022) find that deploying mitigation options can reduce global emissions from gas-fired power by 71 percent with carbon capture and storage, CH_4 abatement, and efficiency upgrades contributing 43 percent, 12 percent, and 5 percent, respectively— this suggested mitigation falls within national responsibilities, except an annual 20.5 $MtCO_2e$ of ocean transport emissions.

Roman-White et al. (2021) note that for LNG, harmonized data collection and reporting would build confidence in supplier claims about LCA emissions, enabling comparisons between natural

Commented [LBD111]: Suggest explain this term

Commented [LBD112]: Can you add a parenthetical example?

Commented [TS113]: This reads like an NETL statement. When quoting another others recommendations or key conclusions, it would help if the text read

Pspeisel et al. 2019 recommends....

Universal comment to ensure clarity on who's recommendations or findings are being discussed.

Commented [LBD114]: Do you mean aggregate emissions in the world? Or GHG emissions?

Commented [EK115]: Please add CCS to the Acronym List.

Commented [LBD116]: Unclear what this means gas supply chains and supporting climate goals for all participants in the supply chain. This could stimulate a virtuous cycle of demand for GHG accounting and reduction and provision of more granular, company-specific emissions estimates.

MacKinnon et al. (2018) demonstrate that natural gas-fired power generation and the natural gas system could play several important roles in supporting sustainable energy strategies over time that can achieve societal GHG reduction goals and help the transition to renewable sources. Natural gas generation can support transitions to renewable resources 1) by use in advanced conversion devices to provide complementary grid services efficiently and with very low emissions to maximize the benefits of intermittent renewable resources (e.g., running a natural gas compression system during peak renewables production), and 2) natural gas generation and the existing natural gas infrastructure can support the use of renewable natural gas with high energy and environmental benefits.

Commented [LBD117]: A term like "natural gas-fired power generation" might be more clear.

According to Stern (2022), three major requirements for creating credible measuring, reporting, and verification of CH_4 emissions are 1) to move measurement and reporting of CH_4 emissions from standard factors—either engineering-based or from EPA data—to empirical (Tier 3) measurements, and to reconcile bottoms-up (ground level) and top-down (satellite/aircraft/drone) observations; 2) to ensure that data measurement and reporting has been verified and certified by accredited bodies; and 3) to require asset-level emissions data to be transparent and publicly available. Failure to do so on grounds of commercial confidentiality risks being interpreted as evidence that the data is not credible.

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3 AIR QUALITY

The natural gas supply chain contributes to air pollution in several ways, including 1) the leaking, venting, and combustion of natural gas during production and 2) the combustion of natural gas and other fossil fuel resources or other emissions during associated operations (e.g., extraction, transportation, downstream combustion). Emissions sources include pad, road, and pipeline construction; well drilling, completion, and flowback activities; and natural gas processing and transmission equipment such as controllers, compressors, dehydrators, pipes, and storage vessels. Pollutants include, most prominently, CH_4 and volatile organic compounds (VOCs)—of which the natural gas industry is one of the highest-emitting industrial sectors in the United States—in addition to nitrogen oxides , sulfur dioxide (SO_2), and various forms of other hazardous air pollutants (HAPs) (Congressional Research Service [CRS], 2020). Pollutants are described in detail below (CRS, 2020):

- CH_4 is the principal component of natural gas and is a precursor to ground-level ozone formation (i.e., "smog").
- NOx is a ground-level ozone precursor. Significant amounts of NOx are emitted during the combustion of natural gas and other fossil fuels (e.g., diesel). The combustion of natural gas occurs when it is flared during drilling and well completions and when used to drive the various compressors that move products through the system. Combustion also occurs in engines, drills, heaters, boilers, and other production equipment.
- VOCs are a ground-level ozone precursor. The crude oil and natural gas sector is currently one of the largest sources of VOC emissions in the United States, accounting for approximately 20 percent of man-made VOC emissions nationwide (and representing almost 40 percent of VOC emissions released by stationary sources). VOCs—in the form of various hydrocarbons—are emitted throughout a wide range of natural gas operations and equipment. The interaction among VOCs, NOx, and sunlight in the atmosphere contributes to the formation of ozone.
- SO_2 is emitted from crude oil and natural gas production and processing operations that handle and treat sulfur-rich, or "sour," gas.
- HAPs, also known as air toxins, are those pollutants that are known or suspected to cause cancer or contribute to other serious health effects including reproductive issues and birth defects. Of the HAPs emitted from natural gas systems, VOCs are the largest group and typically evaporate easily into the air. The most common HAPs produced from natural gas systems are n-hexane and benzene, toluene, ethylbenzene, and xylenes (BTEX) compounds. Some natural gas reservoirs may also contain high levels of hydrogen sulfide (H_2S). HAPs are found primarily in natural gas itself and are emitted from equipment leaks and during processing, compressing, transmission, distribution, or storage operations. HAPs are also a byproduct of incomplete fuel combustion and may be components in various chemical additives.

Commented [LBD118]: "exploration and production"? Are we including exploration?

Commented [EK119]: Please add Nox to the Acronym list.

Commented [LBD120]: Suggest explain in parens or a footnote what compounds this represents

3.1 Upstream Production and Hydraulic Fracturing

The venting of natural gas during extraction and processing is a key source of VOC emissions. Similar to CH_4, VOCs are a naturally occurring constituent of natural gas and can react with other pollutants to produce ground-level ozone.

Emissions of VOCs and CH_4 are lower for offshore conventional production compared to other types of natural gas types because offshore platforms generally have higher production rates helping to justify capital expenditures on loss reduction technologies, which help to prevent unnecessary venting.[h] Another source of VOC emissions during upstream operations is venting from condensate storage tanks, which occurs in regions with wet gas.[i]

The combustion of natural gas in compressors and gas processing equipment produces NOx and carbon monoxide (CO). Similarly, the combustion of diesel in drilling equipment produces NOx and CO, as well as significant quantities of SO_2 emissions. Beyond VOCs, CH_4, NOx, CO, and SO_2 emissions, upstream processes can also produce aliphatic hydrocarbons, (e.g., C2–C5), alkanes, VOCs (e.g., BTEX), H_2S, n-hexane, and formaldehyde, which can contaminate ambient air (Wollin et al., 2020).

Elliott et al. (2017) estimates that up to 143 air contaminants can be released during hydraulic fracturing. The International Agency for Research on Cancer generates hazard assessments for only 20 percent of these identified contaminants. Twenty of these air contaminants are known carcinogens. Other air contaminants are generated by the peripheral plant components. These include particulate matter, NOx, precursors of ozone and polycyclic aromatic hydrocarbons (Wollin et al., 2020).

The following activities are known to contribute to air contamination at oil or gas drilling sites:

- Preparation of the drilling site including road connections
- Drilling of the well
- Truck traffic for delivery and disposal of materials
- Removal of acid gases and water from gas; separation of natural gas from other hydrocarbons
- Operation of compressor stations to enable the transport of natural gas into transport pipelines
- Preprocessing of crude oil prior to refinery

Exhibit 3-1 illustrates the supply chain for natural gas where each of these activities occurs (Wollin, 2020).

Commented [TC121]: Is the a reference for this finding? I would have thought safety at offshore platforms also would have driven lower emission rates.

If we don't have a reference or more supporting documentation, I think the sentence could be deleted without impacting the narrative.

Commented [HSAJ122R121]: Offshore lower profile is due to greater safety measures needed to manage greater risks.

Commented [LBD123]: Suggest explain wet gas vs. dry gas

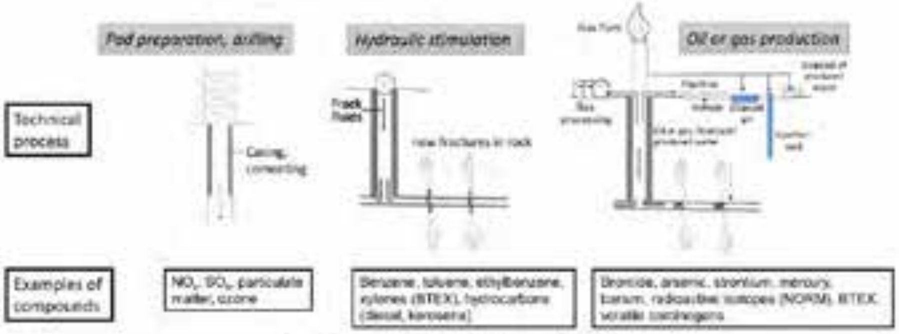
Commented [SW124R123]: I think that would be helpful.

Commented [SH125R123]: Included as footnote.

[h] There are no technological barriers to applying such emission reduction technologies to shale gas or other sources of natural gas.h

[i] When natural gas is retrieved, it can be considered wet or dry. Dry natural gas is at least 85 percent methane, but often more. Wet natural gas contains some methane, but also contains liquids such as ethane, propane or butane. The more methane natural gas contains, the "dryer" it is considered.

Exhibit 3-1. Illustration of supply chain steps where upstream air pollution occurs



Permission pending from Wollin et al. (2020)

NOx and SOx emissions have been reported to be higher during the development of the drilling site compared to during the production phase (Wollin et al., 2020). Similar observations have been made for particulate matter (PM) (e.g., PM2.5 and PM10). Analysis of shale gas production sites in North Texas showed an increase in ozone concentrations by 8 percent at natural gas production sites compared to control sites (Wollin et al., 2020).

Indirect energy consumption can also affect the air quality profile of gas extraction technologies. If the development or operation of a natural gas well uses grid electricity, then the fuel mix of the electricity grid will affect the life cycle performance of the well. The indirect air quality impacts of electricity consumption depend on the fuel mixes and combustion characteristics of power plants that compose a regional electricity grid.

A critical aspect concerning emissions from hydraulic fracturing processes is that several of the organic toxic compounds that are emitted are not regulated. EPA's National Ambient Air Quality Standards only places limits on six Criteria Air Pollutants including CO, ozone near the surface, NOx, PM, SO_2, and lead. Since the N~~ational Ambient Air Quality Standards~~ do not place limits on nor consider the effects of organic compounds beyond those listed previously, EPA's Integrated Risk Information System is frequently used to identify and characterize the health hazards of other compounds. Unlike ~~(NAAQS) National Ambient Air Quality Standards~~, the Integrated Risk Information System does not place any legal restrictions on the release of the compounds it provides data on. ~~As such~~ ~~Therefore, national regulations for the breadth of air emissions released during hydraulic fracturing are insufficient~~. Exhibit 3-2 offers a perspective on non-GHG air pollutant by supply chain step or equipment.

Commented [TC126]: I'm not following the discussion in this paragraph.

Air toxics, or hazardous air pollutants (HAPs), are regulated by EPA under the NESHAP (https://www.epa.gov/stationary-sources-air-pollution/oil-and-natural-gas-production-facilities-national-emission). Would the organic toxic compounds discussed here be regulated under the NESHAP?

Commented [EK127R126]: Agreed. I'm slightly confused as well. After NETL provides clarification, please add NAAQS to the acronym list.

Commented [HSAJ128R126]: Add more context to sharpen discussion.

Commented [LBD129]: "Incomplete"?

Commented [TC130]: Does Exhibit 3-2 use EPA's Integrated Risk Information System? I don't understand the connection between the Integrated Risk Information System and the other statements in this paragraph or the Exhibit.

Exhibit 3-2. Perspective of non-GHG air pollutant by supply chain step or equipment

Source	Air pollutant				Data quality
	NO_X	VOC	PM	Other toxic substances	
Well development					
Drilling rigs	•	+	•	•	Medium
Frac pumps	•	+	•	•	Medium
Truck traffic	•	+	•	•	Medium
Completion venting		•		•	Poor
Frac ponds		+			Poor
Gas production					
Compressor stations	•	•	+	•	Medium
Wellhead compressors	+	+	+	+	Medium
Heaters, dehydrators		+	+	+	Medium
Blowdown venting		+		+	Poor
Condensate tanks		•		+	Poor
Fugitives				+	Poor
Pneumatics		+		+	Poor

• Major source, + minor source

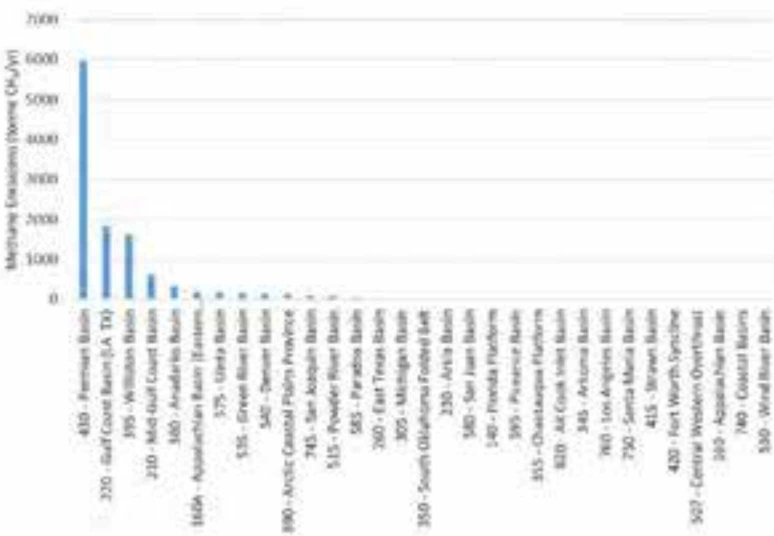
Permission pending from Wollin et al. (2020)

McMullin et al. (2018) analyzed exposure to VOCs emitted during hydraulic fracturing in Colorado. They identified 56 different VOCs that were emitted during hydraulic fracturing using data ~~they~~ compiled from 47 existing air monitoring devices that measured these VOCs at 34 different locations across the region.

Plant et al. (2022) used airborne sampling to measure flare efficiency[i] in three major gas production regions in the United States. They found that both unlit flares and inefficient combustion contribute comparatively to ineffective CH_4 destruction, with flares effectively destroying only 91.1 percent (90.2–91.8 percent; 95 percent confidence interval) of CH_4 emissions. Other emissions from flaring can include carbon particles (soot), unburned hydrocarbons, CO, partially burned and altered hydrocarbons, NOx, and (if sulfur containing material such as H_2S or mercaptans is flared) SO_2. The combustion products of flaring at natural gas production and processing sites specifically include CO_2, CH_4, and N_2O. Exhibit 3-3 illustrates the annual methane emissions from flaring for U.S. production basins (NETL, 2020).

i The flare efficiency is a measure of the effectiveness of the combustion process to fully oxidize the fuel. When inefficiencies occur, unburned fuel, CO, and other products of incomplete combustion (e.g., soot, VOCs, etc.) are emitted into the atmosphere.

Exhibit 3-3. Annual CH_4 emissions from flaring for U.S. production basins



3.2 Midstream Transport Emissions

While the presence of HAPs in unprocessed, upstream natural gas has been documented, little has been published on their presence in the midstream segments of the natural gas supply chain. Nordgaard et al. (2022) systematically evaluated publicly available, industry-disclosed HAP composition data from natural gas infrastructure applications submitted to FERC between 2017 and 2020. These applications covered 45 percent of the U.S. onshore natural gas transmission system (as measured by pipeline miles). Given that reporting HAP composition data is not required by FERC, only 49 percent of approved projects disclosed their HAP composition data to FERC. Of the applications that did disclose their HAP composition data, HAP concentrations were typically reported as higher for separator flash gas and condensate tank vapor, compared to [illegible] and transmission-grade natural gas, with mean benzene concentrations of 1106, 7050, 77, and 37 parts per million, respectively.

Nordgaard et al. (2022) also identified one pipeline operator that reports real-time HAP concentrations for natural gas at five pipeline interconnection points. Similar to the FERC applications, this operator reported BTEX and H_2S as present in the pipelines used to transport their natural gas. ~~Notably, mercury was also reported as detectable in 14 percent of real-time natural gas measurements but was not reported in any FERC applications.~~ Because current transmission infrastructure releases natural gas during uncontrolled leaks, loss of containment events, and routine operations (e.g., blowouts and compressor station blowdowns), having access to HAP composition data may be ~~critical~~ important for conducting both air quality and health-focused evaluations of natural gas releases.

Commented [TC131]: Recommend deleting this figure or moving to the GHG chapter.

Commented [EK132R131]: If we retain the figure and move it to the GHG chapter, I still have the following concern: given the enormous flaring outlier data from the Permian Basin reflects, if there is positive movement there (in Texas and / or New Mexico, etc.) in terms of new / proposed flaring regulations, sustainable practices voluntarily advanced by key / several operators, etc., I suggest we add that additional context to the text narrative. The flaring problems in the Permian profiled previously by EDF and others influenced European buyers (e.g., French utility Engie back in 2020) who became increasingly concerned with and began to oppose the importation of 'dirty gas' from that massive play.

Commented [ST133R131]: NETL: Move to GHG section or delete.

Commented [HSAJ134R131]: Open to making the point but chart should reflect. Reflect flaring is issue in some basins but not nation wide. Don't want to talk about outliers.

Commented [LBD135]: Would it be desireable to provide specific comment on midstream methane emissions, since methane has been cited as an ozone precursor in addition to being a GHG? Possibly it could be a reference to the chapter on GHGs.

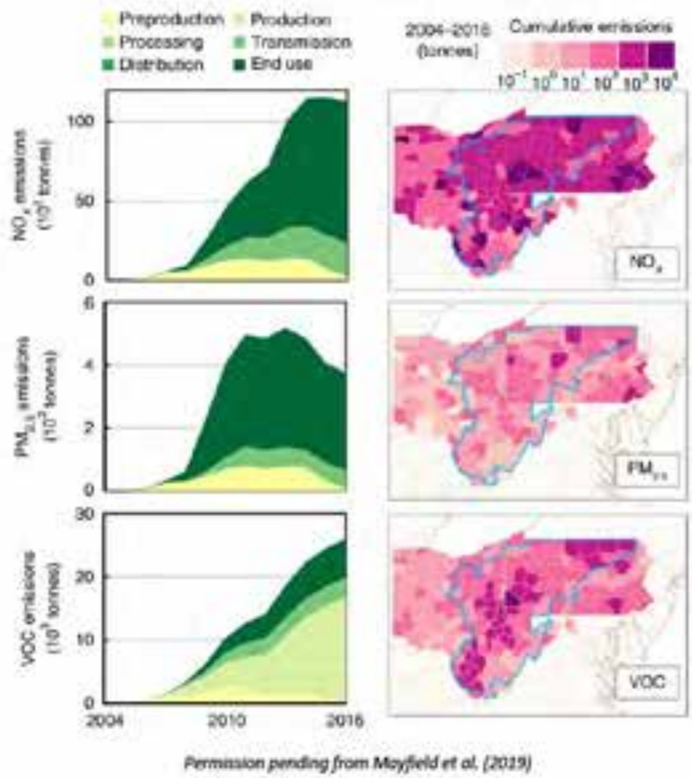
3.3 END-USE PROCESSES

Mayfield et al. (2019) performed an analysis of the environment impacts associated with the shale gas boom in the Appalachian Basin and found the majority (61 percent) of VOC emissions from the natural gas supply chain can be largely attributed to upstream processes and are spatially concentrated in counties with the highest cumulative production. Upstream processes contribute the most to total NOx (67 percent) and PM2.5 (73 percent) emissions across the natural gas supply chain; NOx and PM2.5 emissions are relatively evenly distributed across counties (Mayfield et al., 2019). Exhibit 3-4 presents annual NOx, PM2.5, and VOC emissions from the natural gas supply chain within Pennsylvania, Ohio, and West Virginia, along with the spatial distribution of cumulative NOx, PM2.5, and VOC emissions by county between 2004 and 2016. It is important to note that the blue lines delineate shale gas-producing counties (Mayfield et al., 2019).

Commented [TC136]: Please delete this section, end use emissions are out of scope. Some of the information about upstream air emission source might be appropriate to move above.

Commented [HSAJ137R136]: End-Use is not within scope so we don't need a discussion. Could remove unless there is something recyclable. If so add to another section.

Exhibit 3-4. Annual (left graphs) and cumulative (right graphs) (2004–2016) NOx, PM2.5, and VOC emissions from natural gas supply chain within Pennsylvania, Ohio, and West Virginia



Permission pending from Mayfield et al. (2019)

3.4 References

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Plant, G., Kort, E. A., Brandt, A. R., Chen, Y., Fordice, G., Gorchov Negron, A. M., Schwietzke, S., Smith, M., and Zavala-Araiza, D. (2022). Inefficient and unlit natural gas flares both emit large quantities of methane. Science, 377(6614): 1566–1571. https://doi.org/10.1126/science.abq0385

Wollin, K.-M., Damm, G., Foth, H., Freyberger, A., Gebel, T., Mangerich, A., Gundert-Remy, U., Partosch, F., Röhl, C., Schupp, T., and Hengstler, J. G. (2020). Critical evaluation of human health risks due to hydraulic fracturing in natural gas and petroleum production. Archives of Toxicology, 94(4), 967–1016. https://doi.org/10.1007/s00204-020-02758-7

4 WATER USE AND QUALITY

Commented [HSAJ138]: HH - Comments from Heshem. May need a call between HH and NETL to include more R&D.

The literature describes the treatment and management of wastewaters as the central environmental concern regarding natural gas production. Especially in the eastern regions of the United States where—although water is abundant—significant natural gas production has been occurring. In the western part of the United States, persisting dry climates limit the use and availability of freshwater for natural gas production ~~—~~ . ~~S~~specifically, freshwater availability for drilling and hydraulic fracturing.

Gallegos et al. (2015) estimate that drilling and hydraulically fracturing a shale gas well can consume 2.6–9.7 MM gallons (gal) of water (Gallegos et al., 2015). From 2015 to 2014, unconventional shale gas in the United States used 187 billion (B) gal of water. From 2012 to 2014, the average use for hydraulic fracturing was 30.6 B gal annually. Additionally, Gallegos et al. (2015)'s integrated data from 6–10 years of operations suggest 212 B gal of combined flowback and produced water are produced from unconventional shale gas and oil formations. While the extensive growth in hydraulic fracturing revolution has increased water use for natural gas production across the United States, the water use and produced water intensity of these well stimulation activities~~hydraulic fracturing~~ is lower than the water use and produced water intensity of other energy extraction methods and represents only a small fraction of total industrial water use nationwide (Kondash and Vengosh, 2015). However, even the smallest local or seasonal water supply shortages can cause issues.

Commented [LBD139]: Reverse order?

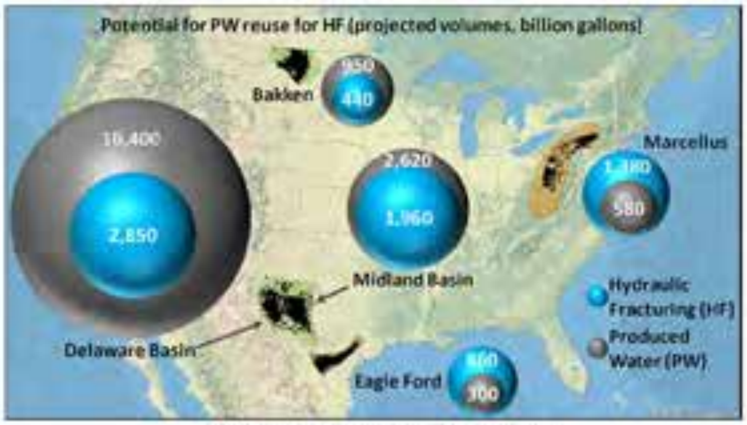
Water quality can also be impacted by natural gas production processes if water is inadequately managed or by the use of fracturing chemicals both on the surface—before injection and after flowback—and in produced water. Subsurface water quality impacts can result from the migration of fracturing fluids, formation waters, and CH_4 along well bores and through rock fracture networks. Management and disposal efforts increasingly include efforts to minimize water use through recycling and re-use of fracturing fluids, in addition to treatment and disposal of wastewater through deep underground injection.

The shale boom has made energy more available and affordable globally, but has also contributed to environmental concerns surrounding the use of water. Scanlon et al. (2020) analyze the water-related sustainability of energy extraction. They focus on meeting the rapidly rising water demand for hydraulic fracturing and managing growing volumes of water co-produced with oil and gas. They also analyze historical (2009–2017) volumes of water in ~73,000 wells and projected future water volumes in major U.S. unconventional oil and gas plays. Their results show a marked increase in fracking water use, depleting groundwater resources in some semiarid regions (Scanlon et al., 2020).

Commented [LBD140]: Volumes of water use?

Water issues related to both fracking water demand and produced water supplies may be partially mitigated through the reuse of produced water to frac ~~for fracking of~~ new wells. As shown in Exhibit 4-1, projected produced water volumes exceed fracking water demand in semiarid Bakken (2.1×), Permian Midland (1.3×), and Delaware (3.7×) oil plays, with the Delaware oil play accounting for ~50 percent of the projected U.S. oil production (Scanlon et al., 2020). Therefore, water issues could constrain future energy production, particularly in semiarid oil plays.

Exhibit 4-1. Map showing ratio between produced water and fracking water demand for major shale basins



Permission pending from Scanlon et al. (2020)

4.1 Water Use for Unconventional Natural Gas Production

Most of the water used for unconventional natural gas production is used for drilling for hydraulic fracturing. For example, of the total water used by the shale gas industry, hydraulic fracturing is estimated to account for about 89 percent, drilling about 10 percent, and infrastructure the remainder (<1 percent) (Hayes and Severin, 2012). Water is also the main component of the fluids used for hydraulic fracturing, making up approximately 99 percent of the total volume.

Reporting from Gallegos, et al. (2015) suggests hydraulic fracturing uses 2.6–9.7 MM gal of water per well drilled, while the American Petroleum Institute (API) (2023) indicates that the average hydraulically fractured well uses 4 MM gal of water. As water is a scarce resource, it is important to consider the potential environmental impacts of using water from different sources (e.g., ground water, surface water). If available surface water is used to support natural gas production, then the ecosystems that rely on this water could be harmed. Significant groundwater withdrawals can also permanently deplete aquifers.

The process of hydraulic fracturing uses large volumes of water mixed with chemicals and proppant (sand) to fracture low-permeability shale and tight oil rocks, allowing the extraction of hydrocarbons ~~to occur~~. Despite the higher water intensity (the amount of water used to produce a unit of energy; for example, liters per gigajoules) compared to drilling conventional vertical oil and gas wells, overall water withdrawals for hydraulic fracturing is negligible compared to other industrial water uses on a national level (Vengosh et al., 2014; Jackson et al., 2014; Kondash, Albright, and Vengosh, 2017; Kondash and Vengosh, 2015). On a local scale, however, water use for hydraulic fracturing can cause conflicts over water availability, especially in arid regions such as the western and southwestern United States, where water supplies are limited (Scanlon, Reedy, and Nicot, 2014; Scanlon et al. 2017; Nicot and Scanlon, 2012; Ikonnikov et al., 2017; Kondash, Lauer, and Vengosh, 2018).

Commented [HSAJ141]: Comment for FE HQ - While this source is older than 2014 it helps to build the context for this section. Please advise if another more recent source is available and we will update accordingly.

Commented [HH142R141]: Hello Amanda.

Thank you for your comment. Please see the references below. Also, please feel free to reference our FOA 2796 (especially in the background section) for updates on the WM program's vision and technical focus areas:

https://www.gwpc.org/wp-content/uploads/2023/05/State-Regulations-Report-2021-Published-May-2023-FINAL.pdf

https://www.gwpc.org/wp-content/uploads/2023/06/2023-Produced-Water-Report-Update-FINAL-REPORT.pdf

https://www.gwpc.org/wp-content/uploads/2021/09/2021_Produced_Water_Volumes.pdf

https://www.energy.gov/fecm/funding-notice-water-research-and-development-oil-and-gas-produced-water-and-coal-combustion

Commented [EK143]: HH: Note about induced seismicity, which has become one of the main reasons for regulatory "Sticks" that are driving technological innovation.

4.1.1 Water Consumption Impacts

Water use for hydraulic fracturing and wastewater production in major shale gas and oil producing regions increased between 2011 and 2016, with water use per well increasing by up to 770 percent—with flowback and produced water volumes generated within the first year of production increasing up to 550 percent. ~~The w~~Water-use intensity (that is, normalized to ~~the~~ energy production) increased in all U.S. shale basins, except the Marcellus shale basin, over this period (Kondash, Lauer, and Vengosh, 2018).

Water consumption per shale gas well can vary due to four conditions:

- *Geology*: maturity of the shale and formation depth, thickness, and lateral extent
- *Technology*: horizontal or vertical drilling, water recycling
- *Operations*: operator decisions, availability of nearby freshwater
- *Regulatory*: requirements for use and treatment of water

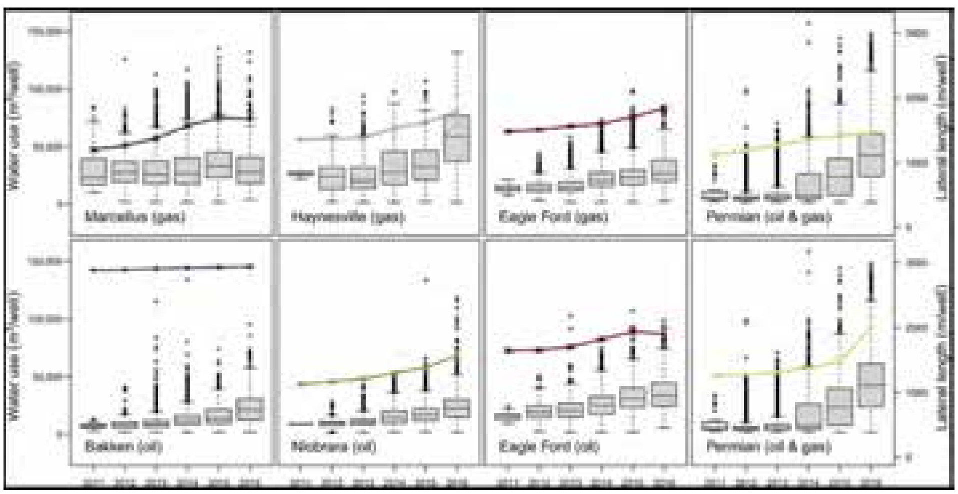
During 2009–2017, ~73,000 wells, or an aggregated total lateral length of ~440 × 10^6 ft (134,000 km), were drilled in the eight studied plays, equivalent to ~3× the Earth's circumference (40,000 km). Dieter et al. (2018) ~~find~~ found that to fracture the rock along that length, a total of ~480 B gal of water was used, equivalent to ~0.1 percent of the U.S. 2015 total water withdrawal, or almost two days of freshwater withdrawal (280 B gal/day). Exhibit 4-2 shows the water consumption for hydraulic fracturing, the amount of produced water used and oil and gas outputs from 9 major plays in the United States (Scanlon et al., 2020). The Eagle Ford play has used 173 B gal of combined hydraulic fracturing and produced water, at nearly a 1.83 ratio of freshwater to produced water and the Marcellus has a freshwater to produced water ratio of 5.83. Other plays use more produced water than freshwater, like Bakken, Delaware, and Barnett, where the ratios of produced water to freshwater are 1.83, 2.21, and 2.11 respectively.

Exhibit 4-2. water use in nine shale plays in the U.S.

Play	Total Length (10^6 ft)	Median Well Length (ft)	Number of Wells	Hydraulic Fracturing Water (10^9 gal)	Produced Water (10^9 gal)	Oil (10^9 gal)	Gas (10^9 gal of oil equivalent)
Bakken	114	9,580	12,036	49	75	100	22
Eagle Ford	95	6,061	17,366	112	61	103	78
Midland	49	8,575	6,461	79	44	30	14
Delaware	36	5,272	7,070	51	113	40	26
Marcellus	51	7,139	9,651	70	12	3	214
Niobrara	21	7,438	3,842	21	5	14	11
Barnett	27	5,241	7,453	35	74	1	111
Haynesville	15	6,270	3,215	30	16	0.03	107
Fayetteville	21	6,386	4,717	24	-	-	55

Exhibit 4-3 from Kondash et al. (2018) indicates that, parallel to the increase in lateral lengths of the horizontal wells and hydrocarbon extraction yields through time, ~~the~~ water use has also increased. The relative increase in lateral length (4–60 percent) was, however, significantly lower than the increase in water use (14–770 percent). When water use per well is normalized to the length of lateral section of the horizontal well, in almost every case among oil producing regions, an increase in water use per length of the horizontal well is observed. This pattern is most evident in the Permian region, where water use increased from 4.4 cubic meter (m^3) per meter in 2011 to 29.3 m^3 per meter in 2016 for gas-producing wells, and from 3.9 m^3 per meter in 2011 to 21.1 m^3 per meter in oil-producing wells. In all cases, with the exception of the Marcellus shale play in 2016, the flowback and produced (FP) water generation ~~was~~ also increased~~ing~~ through time, with particularly higher rates after 2014.

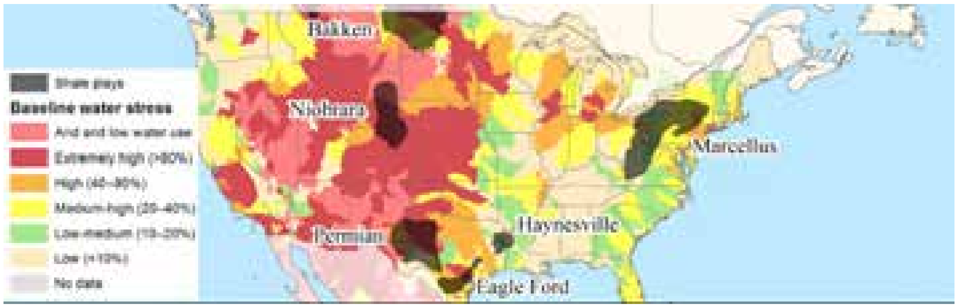
Exhibit 4-3. Water usage and lateral length by shale play



Used with permission from Kondash et al. (2018)

Kondash et al. (2018) also illustrate water conditions where the major plays across the United States are located, see Exhibit 4-4. The Bakken, Niobara, Permian and Eagle Ford plays are all located in arid to extremely dry climates where drought conditions have persisted for many years.

Exhibit 4-4. Baseline water stress and location of shale plays



Permission pending from Kondash et al. (2018)

4.1.2 Water Quality

Concerns have been raised about potential public health effects that may arise if hydraulic fracturing-related chemicals were to impact drinking water supplies. The chronic oral toxicity values—specifically, chronic oral reference values (RfVs) for noncancer effects, and oral slope factors (OSFs) for cancer are available for the list of 1,173 chemicals EPA identified as "associated with hydraulic fracturing." These include 1,076 chemicals used in hydraulic fracturing fluids and 134 chemicals detected in the flowback or produced waters from hydraulically fractured wells.

EPA compiled RfVs and OSFs for these chemicals using six different governmental and intergovernmental data sources. Ninety (8 percent) of the 1,076 chemicals used in hydraulic fracturing fluids and 83 (62 percent) of the 134 chemicals found in flowback/produced water had a chronic oral RfV or OSF reported in at least one or more of the six data sources used. Thirty-six of the chemicals used in hydraulic fracturing fluids have been measured in at least 10 percent of the hydraulically fracted wells drilled nationwide (identified from EPA's analysis of the FracFocus Chemical Disclosure Registry 1.0). Eight of these 36 chemicals (22 percent) had an available chronic oral RfV. The lack of chronic oral RfVs and OSFs for the majority of these chemicals highlights the significant knowledge gap that exists to assess the potential human health hazards associated with hydraulic fracturing (Yost et al., 2016).

Ecological risks to surface waters are present throughout the well life cycle and may manifest themselves differently locally compared to regionally. These risks can also vary temporally, as development activity like surface water withdrawal may only result in a single, brief impact, while the network of roads required for accessing ~~the~~ well pads could increase erosion and sediment runoff for years. Previous work identified the primary risks to surface water quality as sediment runoff from devegetation, leakage and spillage of chemicals into surface waters, unsustainable water withdrawal, landscape fragmentation, and insufficient treatment of oil and gas wastewater prior to discharge (Krupnick, Gordon, and Olmstead, 2013; Slonecker et al., 2012; Drohan et al., 2012; Kiviat, 2013). Unfortunately, few sites exist where baseline environmental monitoring occurred prior to hydraulic fracturing operations commencing (McBroom, Thomas, and Zhang, 2012). This greatly complicates efforts to precisely quantify impacts of hydraulic fracturing, particularly if these operations are occurring in watersheds with preexisting anthropogenic influence and a host of existing ecological stressors (Mauter et al., 2014).

The surface water risks and impacts associated with unconventional resource development ~~will~~ vary significantly by region (Clements, Hickey, Kidd, 2012). To date, those in the Marcellus region have been examined most extensively. This scrutiny has been motivated by the nexus of regionally-specific risk drivers, such as high gradient terrains that could lead to increased erosion, an abundance of small streams, highly variable in-stream flow rates, and the high salinity of produced water in the Marcellus. Moreover, during the early development of the Marcellus shale in ~~PA~~Pennsylvania, the state permitted the disposal of hydraulic fracturing brines in municipal wastewater treatment plants. To reduce the human and environmental impacts associated with this practice, energy and production companies have adopted a moratorium on the disposal of produced water in wastewater treatment plants in ~~PA~~ the state (Wilson and Van Briesen, 2012; Wilson, Wang, and Van Briesen, 2013; Warner et al., 2013; Wilson and Van Briesen, 2013; Renner, 2009).

In the Marcellus and Fayetteville plays, more than 80 percent of the active gas wells are located within 300 meters of drainage areas and recent studies have reported a positive correlation between total suspended solids and the density of upstream gas wells in both the Marcellus and Fayettville.

4.1.3 General Guidelines for Leading Regulatory Practices on Water Sourcing

Increasing demand for water for drilling and hydraulic fracturing in shale gas plays has driven operators to seek supplemental sources of water, and alternatives to local freshwater supplies. Potential alternatives include industrial wastewater, water treatment plant outflows, abandoned mine waters, saline groundwater, and reuse of produced waters.

Ceres (Freyman, 2014) developed a set of guidelines based on gathering the experiences, best practices, and issues throughout the U.S. shale industry. The following is a list developed by Ceres that describes the leading best practices for water sourcing:

- Catalogue the consumptive water use from hydraulic fracturing operations, including sources of water used and the amounts recycled.
- Require information on how operators are planning to manage wastewater streams including final disposal of water.
- Create integrated management structures for joint oversight of ground and surface water (as some are now proposing in British Columbia).
- Realize that higher disclosure requirements alone will not solve water sourcing impacts and risks and must be accompanied by proactive water management plans that include monitoring and enforcement components.
- Ensure that water-sourcing oversight is independent from the department granting oil and gas permits to minimize conflicting mandates and objectives.

Commented [RH144]: It was the State of PA that asked companies to stop doing this, so I would rephrase. According to PSU, "PaDEP asked gas drilling operators to voluntarily stop using these plants for Marcellus wastewater disposal by May 2011 because of mounting water quality concerns downstream of municipal wastewater discharge points." https://extension.psu.edu/waters-journey-through-the-shale-gas-processes

Commented [LBD145]: In places like this where literature cited is of this vintage, it might be helpful to add something saying that these are the most recent studies available. [See global comment at beginning of document.]

Commented [LBD146]: Suggest adding a citation or some reference - the reader has just been provided information from 10+ year old sources, so "recent" could seem ambiguous; if this point is based on more recent information, suggest being as specific as possible about that.

Commented [EK147]: HH: Similar to previous comments—would recommend referencing the GWPC PW handbook, which was recently published. Updated guidelines include managing induced seismicity, CM recovery, and identifying safe beneficial reuse opportunities.

- Create systems of incentives and/or mandate requirements to encourage recycling and non-freshwater use.
- Implement measures to prevent invasive species transfers.
- Provide more resources to map and monitor groundwater resources, including remote aquifers and brackish water resources, across North America.
- Reduce reliance on aquifer exemptions and create incentives to minimize use of deep well injection sites.

4.2 Regulations

Although EPA is generally responsible for water quality by regulating underground injection, hydraulic fracturing is exempt from federal regulation under the SDWA (except when diesel fuel is included in the fluid or there is an imminent and substantial danger to the health of persons). As a result, the responsibility to protect drinking water from hydraulic fracturing activity falls primarily on the states (Zirogiannis et al., 2016).

Rapidly growing demand for water for hydraulic fracturing has challenged water resource managers in many regions. Many state and regional water plans have quickly become outdated as demand for water for shale oil and gas development increases and expands into new regions (Collier, 2011).

States ~~or provinces~~ have the primary responsibility for permitting oil and gas development and related water sourcing, but there is currently significant disparity in their approaches to regulating shale water requirements and associated impacts. A recent study by Resources for the Future (RFF) looked at regulations relevant to shale gas energy development and found markedly different water withdrawal policies across 30 of the states they surveyed, including those with major shale energy development (Exhibit 4-5, states with major shale energy development are outlined in yellow). The study found that for most of the 26 states with any water withdrawal permitting requirements, only half require permits for all withdrawals. Several states do not require permits at all, but only disclosure of water use over a certain threshold, as represented by the light purple states (Freyman, 2014).

In addition, some states ~~and provinces~~ exempt the oil and gas operators industry from permitting requirements for water withdrawals, including the following:

- Kentucky, which exempts the industry from both surface and groundwater reporting
- Texas, which requires permits for surface water withdrawals, but generally not for groundwater

Commented [HH148]: The Groundwater Protection Council recently published a report on the state of produced water as well as state regulations.

Please reference the reports to ensure changes, especially state regulations, are represented:

https://www.gwpc.org/wp-content/uploads/2023/05/State-Regulations-Report-2021-Published-May-2023-FINAL.pdf

https://www.gwpc.org/wp-content/uploads/2023/06/2023-Produced-Water-Report-Update-FINAL-REPORT.pdf

https://www.gwpc.org/wp-content/uploads/2021/09/2021_Produced_Water_Volumes.pdf

Commented [TC149]: Please remove this section.

Commented [LBD150]: This verb tense (present perfect) doesn't match well with a source that is 12 years old – realizing that some editing is ongoing, but just pointing this out.

Exhibit 4-5. Water withdrawal regulations by state

Used with permission from Richardson et al. (2013)

In many cases, states where hydraulic fracturing is taking place have had to set their own regulations. The following is a list of examples of state-based water regulations related to hydraulic fracturing. This list is not exhaustive.

4.2.1 Pennsylvania

Pennsylvania is leading the way in requiring strong disclosure of freshwater and recycled water use during hydraulic fracturing. Within 30 days after completion of a well, the operator must submit a completion report to the Pennsylvania Department of Environmental Protection (PADEP). That report must include a stimulation record, which provides technical details associated with hydraulic fracturing, and list water resources that were used under an approved water management plan, including volume of water used from each source (25 Pa. Code § 78.122(b)(6); 25 Pa. Code § 78.122(b)(6)(vi)). Operators must also disclose the volume of recycled water used during well drilling (25 Pa. Code § 78.122(b)(6)(vii)). The PADEP then reviews individual plans and approves them, provided that water withdrawals:

- Do not adversely affect the quantity or quality of water available to other users of the same water sources.
- Protect and maintain the designated and existing uses of water sources.
- Do not cause adverse impact to water quality in the watershed considered as a whole.
- Are mitigated through a reuse plan for fluids that will be used to hydraulically fracture wells (58 Pa. Cons. Stat § 3211(m)(2)).

Other PA water regulations include the following:

- § 78a.15: If the proposed limit of disturbance of the well site is within 100 ft measured horizontally from any watercourse or any high quality or exceptional value body of water or any wetland 1 acre or greater in size, the applicant shall demonstrate that the well site location will protect those watercourses or bodies of water.
- § 78a.51. Protection of water supplies
    - A well operator who affects a public or private water supply by pollution or diminution shall restore or replace the affected supply with an alternate source of water adequate in quantity and quality for the purposes served by the supply as determined by the Department.
    - A landowner, water purveyor or affected person suffering from pollution or diminution of a water supply ~~as a result of~~ due to oil and gas operations may ~~to~~ notify the Department and request that an investigation be conducted. Notice shall be made to the appropriate Department regional office or by calling the Department's Statewide toll-free number at (800) 541-2050. The notice and request must include the following:
- Require operators to demonstrate how they will prevent damage to aquatic life during water withdrawals.[8]

Commented [EK151]: NETL Team - if we don't have the information / text to complete this sentence, I suggest we strike it altogether.

4.2.2 Colorado

The Air Pollution Control Division issued revised versions of Operating and Maintenance Plan Templates for Produced Water Storage Tanks.

In January 2013, the Colorado Oil and Gas Conservation Commission (COGCC) approved the most rigorous statewide mandatory groundwater sampling and monitoring rules in the United States. The purpose of Rule 609, "is to gather baseline water quality data prior to oil and gas development occurring in a particular area, and to gather additional data after drilling and completion operations" (COGCC, 2020).

Wells are constructed with multiple layers of steel casing and cement; COGCC rules require the following specifications for each well:

- In the water-bearing and hydrocarbon zones, the casing is cemented into place, and cement fills the void space between each layer of casing.
- At least two layers of steel casing and cement are in place from the ground surface to the lowest point of the freshwater aquifer.
- In the hydrocarbon formation, several thousand feet below the aquifer in most cases, there is at least one layer of steel and cement, and the hydrocarbons move through the inner-most casing to the surface.

[8] See section C.6 titled "Withdrawal Impacts Analysis," in the PADEP Water Management Plan For Unconventional Gas Well Development Example Format (2013).

Colorado requires disinfection of water suction hoses when water withdrawals occur in cutthroat trout habitats to avoid transfer of invasive or harmful species (Colo. Code Regs. § 404-1:1204, Westlaw 2012.).

4.2.3 Texas

The RRC (the agency that regulates the state's oil and gas industry) recently amended its rules to make it easier to recycle wastewater streams from hydraulic fracturing operations. Operators no longer need permits to recycle water and can even accept water from other areas or companies, as long as the recycling takes place on land leased by the operator so that oversight can be maintained. This new rule also allows operators to turn around and sell the water to other operators (Osborne, 2013).

4.2.4 Ohio

Ohio's freshwater and recycled water use rules require operators to identify each proposed source of groundwater and surface water that will be used (Ohio Rev. Code §1509.06(A)(8)(a).). Ohio does not, however, require post-drilling disclosure of actual volumes of freshwater and recycled water used.

4.3 Current Research and Development and Analysis

NETL is performing advanced remediation technology research to better manage effluent water from energy production. The Water ~~Energy Effluent~~ Management Program aims to ensure that American water is affordable, reliable, sustainable, and resilient for energy use, and to reduce the environmental impact of freshwater consumption for energy production related to oil and gas operations (and coal combustion) as well as to reduce the volume of produced water disposal during oil and gas activities by:

- Improving treatment methods for produced water constituents that are ~~both~~ hard, ~~and~~ costly, ~~and energy intensive~~ to treat.
- Increasing the beneficial use possibilities for treated produced water outside of the oil and gas industry.
- Reducing environmental impacts related to produced water such as freshwater consumption in water scarce regions and induced seismicity.
- Characterizing produced water and energy effluent waters to identify potential resources such as critical minerals that could be harvested for uses within other industries.

To support this vision, the program aspires to reduce the environmental impact of freshwater consumption for energy production related to oil and gas operations and coal combustion as well as to reduce the volume of produced water disposal during oil and gas activities. The research areas include the following:

- Treatment technologies – developing effective and cost-effective technologies and treatment trains to treat produced water

Commented [EK152]: May want to state the actual year rather than 'recently' - especially if this reference is about a regulatory action that's no longer recent in 2023.

Commented [EK153]: HH: This is one of the few times we mention coal in this section--should we mention it throughout the section or should we remove reference to coal altogether?

- Beneficial use technologies – increasing the likelihood that treated produced water can be utilized in other industries besides oil and gas
- Resource characterization – characterization of produced water constituents for potential harvesting for other industrial uses

A goal of the program is to engineer water composition to improve imbibition into the formation matrix with ionic modification, surfactants, and nanoparticles, which can change the wettability of carbonate rocks toward more water-wet conditions under which water can imbibe into the matrix and displace oil into the fractures. The modified water composition will be injected to improve oil recovery from the carbonate matrix in fractured reservoirs. The result can increase production from the well with no increase in the amount of water, chemicals, proppants, and energy required. This translates to minimized air emissions and other environmental impacts associated with production of a unit volume of oil and gas.

Currently, Water Management Program has existing projects:

- Develop effective treatment technologies to treat produced water via energy- and cost-efficient approaches for use within the oil and gas industry (2 projects)
-
- Develop advanced or novel membrane specific technologies for treatment of produced water (1 project)
- Developing methods characteriz extract rare earth elements or critical minerals (project)

4.4 References

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Commented [EK154]: HH: Would it be possible to provide the names of the projects? We have three additional ones in a university partnership effort, as well as initiatives in the digital space—just to ensure I don't double count.

Commented [ST155R154]: NETL: we need to ensure consistency in the depth and breadth of R&D sections across the chapters. Lets discuss.

Commented [EK156]: HH: Our program pivoted from this some time ago and we are no longer pursuing research in this area.

Commented [EK157R156]: HH: Please reference language about the new program from the NETL article (page 2). Text also copied below:

The Department of Energy (DOE) Office of Fossil Energy and Carbon Management (FECM) is celebrating the integration of the produced water (PW) management research and development (R&D) activities (originally housed within NETL Oil & Gas upstream research) with the Water Management for Power Systems program (operated under NETL's Crosscutting Research Program). These joined programs will be based in the Advanced Remediation Technologies Division (ART). The water-related R&D within FECM will be executed by ART-Water Management (ART-WM), representing one of the first combined programs of its type within DOE.

ART-WM's mission is to deliver societal benefits

Commented [EK158R156]: HH: This does not include the 7-8 FOA awards which will be announced in the coming weeks - yes?

Commented [EK159R156]: @Hadjeres, Hichem - I'm doing my best to integrate your excellent peer review feedback into this Sharepoint version of the Addendum. That said, I'm not exactly sure what you need with this comment RE: the 7-8 FOA

Commented [HH160R156]: @Easley, Kevin we are expecting another 7-8 projects to be added to our portfolio, which will cover new areas (e.g. CM recovery and extraction). The awards are expected to be made in a few weeks. The

Commented [EK161R156]: OK, thanks for the clarification, Hichem. I'll bring this up tomorrow when I meet with @Sweeney, Amy and @Curry, Thomas.

Commented [HH162R156]: @Easley, Kevin Thanks, Kevin!

Commented [HH163]: Please feel free to reword—basically talking about analysis and modeling of produced water samples and the work we do through PARETO to optimize PW management

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5 INDUCED SEISMICITY

Induced seismicity is ground motion (earthquakes) caused by human activities. Earthquakes have been detected in association with both oil and natural gas production, underground injection of wastewaters (i.e., wastewater disposal), and hydraulic fracturing (Rubinstein and Mahani, 2015). Each of these processes involves injecting large volumes of foreign fluids at various pressures into underground formations.[1] Earthquakes from induced seismicity have happened in multiple countries, including ~~in~~ the United States (Shultz et al., 2020).

5.1 IMPACTS FROM INDUCED SEISMICITY AND ENERGY TECHNOLOGIES

The term seismic activity is generally used to describe vibrations of mechanical energy that pass through the earth, much like sound waves vibrate through the atmosphere. The seismic activity of a region is defined by the frequency, kind, and magnitude of earthquakes experienced in the region during a given period. The National Earthquake Information Center (NEIC) is the entity responsible for determining, as rapidly and as accurately as possible, the location and size of all significant earthquakes that occur worldwide. At present, the NEIC locates and publishes detailed data on the 30,000 "most significant" earthquakes that occur in each year (USGS, 2023).

While millions of earthquakes occur each year, not all are felt at the surface. Earthquakes with magnitudes of 2.0 or less generally cannot be felt at the surface by people, while earthquakes with magnitudes greater than 3.0 tend to produce noticeable shaking. Earthquakes with magnitudes greater than 5.0 are felt at the surface and have the potential to cause structural damage to buildings and property. Most earthquakes that do occur are in response to natural, yet sudden slips and shifts of large masses of rock along geologic faults.

The seismicity rate in the central and eastern United States increased 40-fold within the past decade, predominantly as a result of human activities (Ellsworth, 2013; van der Baan and Calixto, 2017). This recent increase in seismicity rate in the central and eastern United States has largely been attributed to large-volume wastewater disposal wells injecting fluids into deep sedimentary formations (e.g., Keranen et al., 2014; Rubinstein and Mahani, 2015). Other human activities, including hydraulic fracturing (Skoumal, Brudzinski, and Currie, 2015) and carbon sequestration (e.g., Kaven et al., 2015), have induced seismicity to a lesser extent in the central and eastern United States (Skoumal et al., 2020).

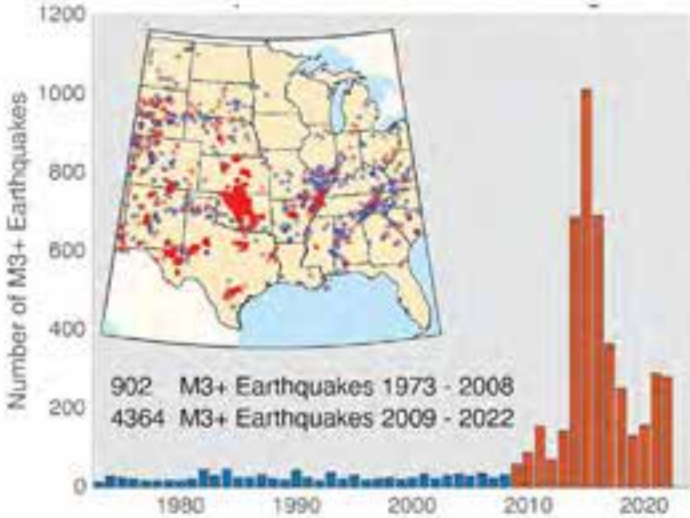
Commented [LBD164]: Suggest update phrasing to more precise years as this reads as 2013-2023 to a current reader.

Exhibit 5-1 presents the annual number of earthquakes (with a magnitude of 3.0 or larger) occurring in central and eastern areas of the United States for 1973–2022. Many of these earthquakes have taken place in areas where hydraulic fracturing has been and is actively occurring (e.g., Oklahoma) (USGS, 2022). Between 1973 and 2008, approximately 25 earthquakes of magnitude three or greater occurred on average annually. Since 2009, at least 58 earthquakes of this same size (magnitude of 3.0 or larger) have occurred annually, and at

[1] Hydraulic fracturing involves injecting large volumes of fluids into the ground to release trapped oil and natural gas. Wastewater from oil and gas production, including shale gas production, is typically disposed of by being injected at relatively low pressures into extensive formations that are specifically targeted for their porosities and permeabilities to accept large volumes of fluid.

least 100 earthquakes of this same size have occurred annually since 2013. The annual number of earthquakes (with a magnitude of 3.0 or larger) peaked in 2015 when 1,010 magnitude 3+ earthquakes were recorded. Given their magnitude, most of these earthquakes are large enough to have been felt by people, yet ~~small~~ not large enough to cause significant damage (USGS, 2022).

Exhibit 5-1. Earthquakes in the Central and Eastern U.S. 1973–2022



The following are examples of induced seismic events in the United States that have occurred in basins where unconventional natural gas production via hydraulic fracturing has occurred.

5.1.1 Utica and Marcellus Shales in the Appalachian Basin

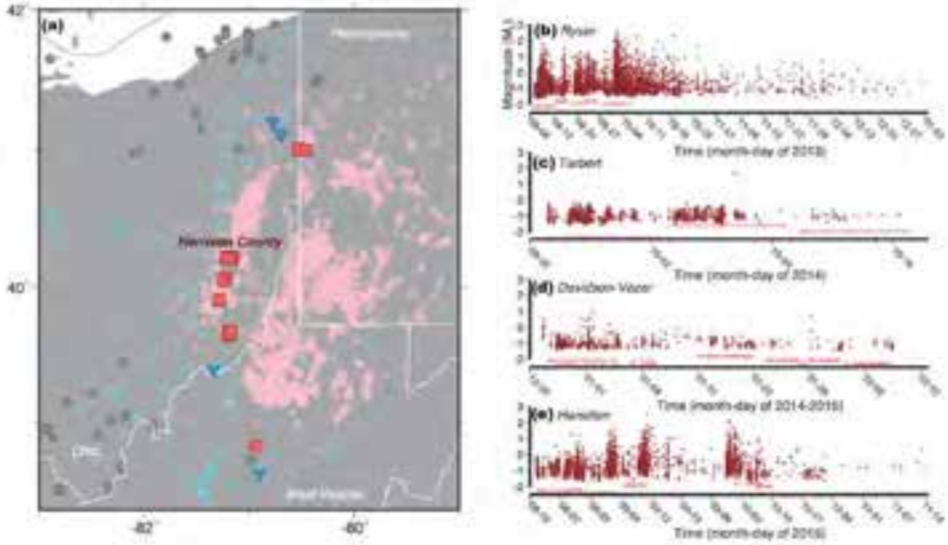
The Appalachian Basin is currently the largest natural gas producing area in the United States. The basin produced over 18 Mcf of natural gas a day (500 m^3/day) in 2019 (EIA, 2019a). The Marcellus and Point Pleasant Utica shale plays are both located in the Appalachian Basin and extend from New York to Kentucky. They each cover prospective areas of 190,000 and 220,000 square kilometers (km^2), with proven reserves of 135 and 24 Tcf of natural gas, and 345 and 210 MM barrels of oil, respectively (EIA, 2019b). Earthquakes detected in the basin during 2013–2015 are presented in Exhibit 5-2.

Commented [EK165]: Is the 2015 induced seismicity information presented here sufficiently 'recent' for the purposes of this Addendum? Is more recent data available from USGS as the graph at the top of the page and supporting text narrative refers to a 2022 data source.

The map on the left provides the location sequences of cataloged (magnitude > 2.0) seismic events in Ohio and neighboring states for 2010–2017. Blue triangles show earthquake sequences induced by wastewater disposal; red squares show earthquake sequences induced by hydraulic fracturing; and pink squares and blue triangles depict the horizontal and wastewater disposal wells that remain in the area. Grey circles represent earthquakes assumed to be occurring from natural causes. The four graphs on the right provide the temporal

distribution of hydraulic fracturing induced seismic events for four wells in Harrison County, Ohio (Schultz, 2020).

Exhibit 5-2. Location and timing of induced and natural seismic events in the Appalachian Basin



Permission pending from Schultz (2020)

5.1.2 Anadarko and Arkoma Basins of Oklahoma

Dramatic increases in seismic activity have been reported for areas in both central and northern Oklahoma, where the Anadarko and Arkoma Basins are located. Historically, an average of one to two ML[m] ≥ 3.0 earthquakes occurred in Oklahoma annually. The number of ML ≥ 3.0 earthquakes occurring in the state, however, rose to over 900 in 2015.

While the seismicity rate began to decline in 2016 the yearly total seismic moment of Oklahoma remained high in response to three Mw[n] ≥ 5.0 earthquakes occurring during the year. Including the Pawnee earthquake, the largest earthquake (5.8 Mw) ever recorded for the state of Oklahoma. The seismicity rate increase has generally been attributed to the disposal of large volumes of produced water into the Arbuckle Group basin (Haffener, Chen, and Murray, 2018).

Exhibit 5-3 shows the location (left) and magnitude (right) of induced seismic events in Oklahoma between 2010 and 2020. In the map on the left seismic events from natural causes are represented by the blue circles, while induced seismic events are represented by the red (Skoumal et al., 2018) and orange circles (Shemeta, Brooks, and Lord, 2019). The graph on the

Commented [EK166]: NETL Team - 'moment' (as written) or events or some other term? If 'moment,' it's unclear what message / finding the sentence is trying to convey. Also, 'of' Oklahoma' (as written) or 'in' Oklahoma.

Commented [EK167]: NETL Team - this sentence appears to be incomplete. If it is meant to amplify the preceding sentence, I suggest it be reworded as it's confusing / unclear as written.

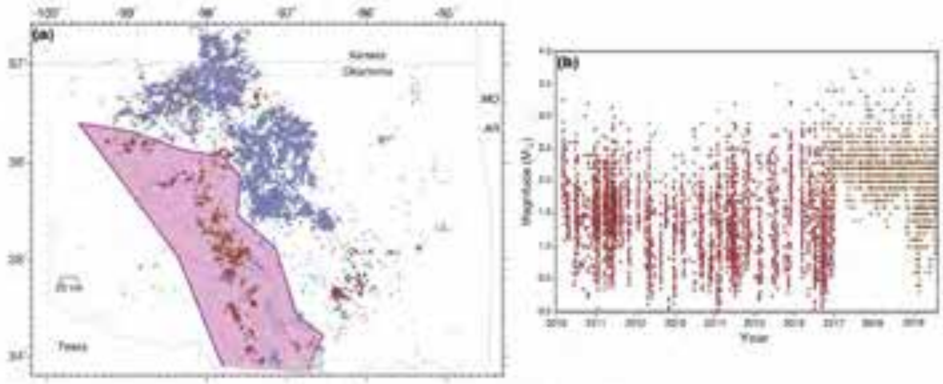
[m] ML refers to the magnitude on the Richter scale, where M stands for magnitude and L stands for local.

[n] Mw is known as the moment magnitude of an earthquake. For very large earthquakes, moment magnitude gives the most reliable estimate of earthquake size.

left shows the number and magnitude of the induced seismic events over time (Skoumal et al., 2018; Shemeta, Brooks, and Lord, 2019).

Commented [EK168]: NETL Team - did you mean to type the graphy on the right in Exhibit 5-3 as it's the one that has a 'time series' (2010 - 2019) along the horizontal axis.

Exhibit 5-3. Induced seismicity events in Oklahoma



Permission pending from Schultz (2020)

5.1.3 Fayetteville Formation in the Arkoma Basin of Arkansas

Following the success of the Barnett Shale (Fort Worth Basin, Texas) the Fayetteville Formation in Arkansas became an early target for continued shale gas development in the United States. This unconventional play runs east to west across north central Arkansas, extending across nearly 150 km. By 2005, horizontal well completions in the middle to lower organic rich facies at depths typically 1–2 km were coming online and, by 2009, 0.5 Tcf of gas was being produced per year (Browning et al., 2014).

The Fayetteville Formation has a history of seismicity that dates back to before the region was developed for oil and natural gas extraction. In September 2010, a series of seismic events reaching magnitudes close to 5.0 Mw on the Richter Scale occurred along the Guy-Greenbrier Fault within the basin. Not long after, on February 28, 2011, a 4.7 Mw earthquake—the largest ever recorded—occurred within the basin. This led to concerns that even larger earthquakes could potentially occur in the area, which resulted in an emergency shutdown order for any injections being put in place by the Arkansas Oil and Gas Commission. Analysis of the seismicity, injection patterns, and pore pressure diffusion built a strong case for the activation of the Guy-Greenbrier Fault by wastewater disposal (Horton, 2012; Ogwari, Horton, and Ausbrook, 2016; Ogwari and Horton, 2016; Park et al., 2020). In the neighboring states of Oklahoma and Texas, wastewater disposal by injection is understood to be the primary driver of induced seismicity.

5.1.4 Eagle Ford Shale Play in the Western Gulf Basin of Texas

Texas has a long history of active oil and natural gas production, hydraulic fracturing, wastewater disposal, and general seismicity, ~~S~~some of which occurs within or near areas of

pervasive faulting (see Exhibit 5-4a) (Ewing, 1990; Frohlich et al., 2016). Advancements in horizontal drilling and hydraulic fracturing since 2008 have prompted the Eagle Ford shale play to focus on hydrocarbon production from the Upper Cretaceous Eagle Ford and Austin Chalk Formations (Frohlich and Brunt, 2013; Martin et al., 2011; Pearson, 2012; RRC, 2019).

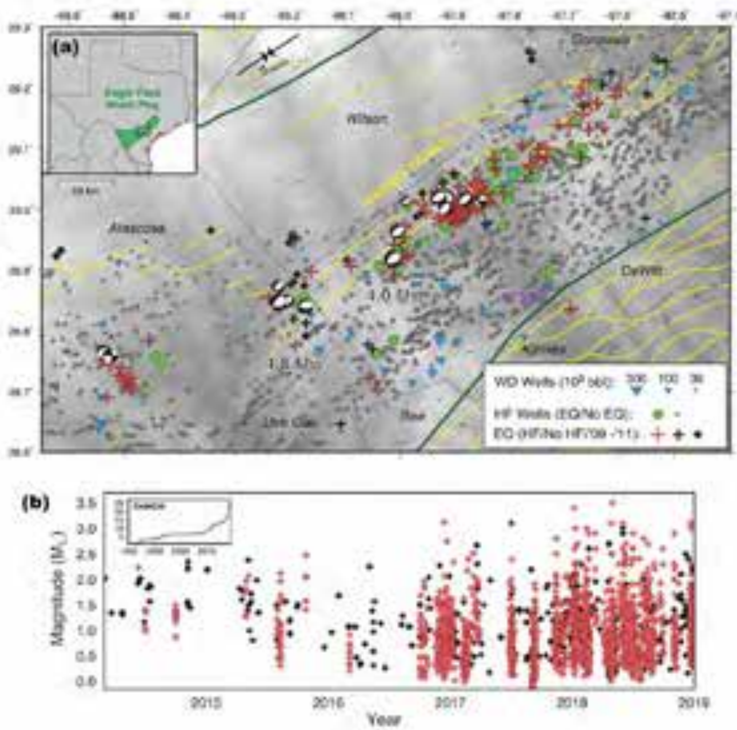
In 2018, the rate at which ML ≥ 3.0 earthquakes occurred in the Eagle Ford shale play was 33 times higher than background levels (3 earthquakes per 10 years during 1980–2010; see Exhibit 5-4b). Fasola et al. (2019) investigated seismicity that has occurred since 2014, in an effort to identify how hydraulic fracturing has contributed to seismicity within the play. Comparing both times and locations of hydraulic fracturing to a catalog of seismic activity, Fasola et al. (2019) suggest more than 85 percent of the seismicity that occurred was spatiotemporally correlated with hydraulic fracturing. More specifically, there were 94 ML ≥ 2.0 earthquakes correlated will 211 hydraulic fracturing well laterals.

Commented [EK169]: NETL Team - 'will' (as written) or 'with' - or perhaps something else?

Exhibit 5-4a provides a map from the Texas Seismological Network showcasing earthquakes (crosses) and focal mechanisms (beach balls) that have occurred since 2017. Hydraulic fracturing wells are indicated by black circles in Exhibit 5-4. Correlated earthquakes and hydraulic fracturing wells are displayed as red plus signs and green circles, respectively. Black diamonds show the earthquakes that occurred during 2009–2011 (Frohlich and Brunt, 2013). Purple square shows the seismic station (735B) used for template matching. Wastewater disposal wells are provided as teal triangles sized by median monthly volumes. Arrows show regional orientation (Lund Snee and Zoback, 2016). Faults (Ewing, 1990) are in yellow.

Exhibit 5-4b provides the magnitudes of the various earthquakes both correlated and not correlated with hydraulic fracturing that occurred annually after 2011 within the play (the black and red plus signs shown in Exhibit 5-4a). The inset shows the cumulative number of earthquakes (magnitude ≥ 3.0) occurring in the area, available from the United States Geological Survey (USGS) Comprehensive Catalog.

Exhibit 5-4. Locations and timings of Eagle Ford hydraulic fracturing induced event



Permission pending from Fasola et al. (2019)

5.2 Regulations to Address Induced Seismicity and On-Going Research and Development

State regulators have long been focused on identifying the precise location and magnitude of earthquakes and determining their cause. When earthquakes can be linked to wastewater injection, regulators [illegible] operators to cease or limit either injection rates and/or water volumes in nearby wells (EPA UIC National Technical Workgroup, 2015). Many regulators also require that new injection wells avoid areas near known active faults. In Oklahoma, these techniques have effectively reduced the number of felt earthquakes.

Similar procedures have been applied to hydraulic fracturing operations in some states. That is, when earthquakes are detected, operations are either modified or suspended (AGI, 2017). Oklahoma, Texas, and Ohio have all taken steps to mitigate induced seismicity linked to hydraulic fracturing. In Oklahoma, regulators have instituted the following actions to address induced seismicity (Boak, 2017)

- Governor created the Coordinating Council on Seismicity (2014)

Commented [EK170]: NETL Team - Changed 'If' to 'When' since the Addendum has already cited wastewater injection is one driver of induced seismicity.

- Oklahoma Corporation Commission directives reduce injection (2015)
- Oklahoma Geological Survey position paper published (2015)
- Secretary of Energy fund $200,000 seismicity projects (2015)
- Governor's Water for 2060 Produced Water Working Group (2015)
- Research Partnership to Secure Energy for America funded stations that were added to the Oklahoma Geological Survey network (2016)
- Governor's Emergency Fund allocated $1,387,000 to bolster the emergency response capacity of the Oklahoma Corporation Commission and Oklahoma Geological Survey (2016)
- Created a tracking system for earthquakes and injection activities for the Oklahoma Corporation Commission to monitor and assess these events and operator practices (2016)

In Texas, the state's Center for Integrated Seismicity Research (TexNet) is charged with monitoring, locating, and cataloging seismicity across the state. Capable of detecting and locating earthquakes with magnitudes ≥ 2.0. TexNet's backbone network improves investigations of ongoing sequences of seismic activity by deploying temporary seismic monitoring stations and conducting site-specific assessments (Young et al., 2017). TexNet will continue to conduct fundamental and applied research to better understand both naturally and potentially induced seismic events that are occurring across the state of Texas, their associated risks, and potential strategies for communicating with stakeholders and responding to public concerns raised regarding seismicity. (Young et al., 2017)

Additional state requirements and activities associated with seismicity include the following (Young et al., 2017):

- Applicants are required to search the USGS seismic database for historical earthquakes within a circular area of 100 square miles around a proposed, new disposal well (~5.6-mile radius)
- Clarifying the Texas Railroad Commission's (RRC) authority to modify, suspend or terminate a disposal well permit, or modify operations if scientific data indicates a disposal well could be contributing to seismic activity
- Increased disclosure of reported volumes and pressures, at RRC's discretion
- RRC may require applicants to provide additional technical information to demonstrate disposal fluid confinement

Ohio has regulated seismic permits for injection wells for some time; obtaining a permit can require the following tests or evaluations of a proposed brine injection well be completed, in any combination that the chief deems necessary (Dade, 2017):

Commented [EK171]: NETL Team - to your knowledge, is this 2015 funding reference the most recent DOE / S-1 investment into induced seismicity projects?

Commented [LBD172]: Is any update available?

Commented [EK173]: NETL Team - It's unclear who the 'Applicants' are, what they are applying to, etc. Please provide additional details.

Commented [EK174R173]: Are we referring to operators in Texas applying for permits of one type or another RE: drilling, disposal, etc.? Please clarify.

Commented [LBD175]: Is any update available?

- Geological investigation of potential faulting within the immediate vicinity of the proposed injection well location, which may include seismic surveys or other methods determined by the chief to assist analysis.
- Permit conditions may include seismic monitoring, pressure fall-off tests, spinner tests, radioactive tracer, geophysical and electrical logs, and downhole pressure monitoring.

Restrictions may be placed on wells drilled near faults or areas known for seismic activity, in which seismic monitors must be installed for a specified period prior to completion operations (Dade, 2017). Related actions include:

- ML ≥ 1.5 – Direct communication starts between operator and division
- ML = 2.0–2.4 – Work with operator to propose or modify operation
- ML ≥ 2.5 – Temporary halt completions on lateral
- ML = 3.0+ – ompletion on pad suspended until an

The mitigation techniques employed by Ohio include the following:

- Direct communication with the operator is essential
- Discussion of seismic events and stages of the operation need to occur in real-time
- Spatial analysis and time correlation with completion data conducted during the operation

Mitigation techniques when induced seismicity occurs during hydraulic fracturing include the following:

- Change from zipper fracking to stack fracking
- At least 20% reduction in volume and/or pressure
- Skipping stages may be necessary, especially if seismic events indicate a lineament or fault structure near a lateral of the operation
- Switch to smaller sieve sizes for proppant, full effect still unsure

Commented [EK176]: NETL Team - the 'shorthand' in these bullets is confusing, poorly written, and as such I'm uncertain if my proposed text revisions are correctly adjusting the text to make it more understandable. Please feel free to expand upon / revise this section as needed.

Commented [EK177]: NETL Team - please flesh this out as this is very technical terminology many prospective users / readers of the Addendum may not readily recognize / understand.

Commented [EK178]: NETL Team - please add some text to describe why stages may need to be skipped due to seismic events indicating "a lineament or fault structure near a lateral of the operation."

Commented [EK179]: NETL Team - what is meant by / the consequences of this phrase: "full effect still unsure' when switching to smaller sieve sizes for proppant.

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6 LAND USE AND DEVELOPMENT

The growing land use footprint of energy development, termed "energy sprawl," ~~will~~ likely causes significant habitat loss and fragmentation with associated impacts to biodiversity and ecosystem services (McDonald et al., 2009). Land presents a critical yet often overlooked constraint to energy development, including the development of domestic natural gas. Natural gas is set to act as a transition fuel and dominant technology during the grid decarbonization process in the United States, making an understanding of its land use implications critical and necessary consideration (Dai et al. 2023).

Expanding energy development is now the primary source of anthropogenic land cover change in natural ecosystems in North America (Allred et al., 2015; Trainor, McDonald, and Fargione, 2016), including eastern deciduous forests, boreal forests, prairie grasslands, sagebrush-steppe, and deserts (Copeland, Pocewicz, Kiesecker, 2011; McClung and Moran, 2018; Appiah, Opio, Donnelly, 2019). Land use and development issues associated with natural gas production include local surface disturbance; cumulative landscape impacts; habitat fragmentation; and traffic, noise, and light. Vertical wells are typically spaced with 40 acres per well, the drill pads from which each horizontal well originates are typically spaced with 160 acres per well. If wells are drilled conventionally (i.e., vertically) a single square mile of surface area can support 16 pads with one well per pad. If wells are drilled horizontally then the same amount of surface area could ~~support~~ be used to develop 1 pad, from which 6–8 different wells could be drilled (NETL, 2009).

The Citizens Marcellus Shale Coalition (CMSC) (2011) explored two issues related to impacts of shale gas production on public lands and the other industries that rely on these lands. They also explored ~~the~~ impacts on private property rights. CMSC stated that shale gas development must consider the cumulative impacts on state parks and forests and on timber and tourism industries as part of responsible stewardship of public resources. Property rights and environmental degradation are a growing public concern, and eminent domain laws, drill spacing requirements, and grouping of leased lands could help protect these rights.

Commented [HSAJ180]: Comment for PE/HQ : In some cases the best source of information we had for land use impacts predated 2014. Please advise if you would like to see these removed.

Commented [EK181R180]: Amanda - I love that paragraph. Except for the '2011' reference in parentheses. Do we have to 'hang a lantern' there on how dated that reference is? If what was true then remains true today, I would prefer we remove the "(2011)" reference and continue along. Anyone else have strong feelings on this? @Curry, Thomas @Skone, Timothy @Lavoie, Brian D.

6.1 SURFACE DISTURBANCE AND LANDSCAPE IMPACTS

The infrastructure ~~to~~ needed to support the supply chain of electricity produced from natural gas involves production sites (production pads and their access roads), transportation facilities (e.g., gathering and transmission pipelines for natural gas), processing facilities, and power plants (end-use) (Dai et al., 2023). Such activities can disturb Earth's surface, the impacts of which can extend over large areas and result in habitat fragmentation that impacts both plant and animal species. Mitigation options include adoption of best-practices for site development and restoration, avoidance of sensitive areas, and minimization of impacts to disturbed areas.

Dai et al. (2023) used machine learning, remote sensing, and geographic information systems to obtain spatially explicit information on the land required to support natural gas production. Their analysis considered land use across five life cycle stages of natural gas produced for electricity production from wells (production stage), natural gas transportation via gathering pipelines (gathering stage), natural gas processing ~~plants~~ (processing stage), natural gas

Commented [EK182]: NETL Team - suggest removing 'plants' here as we're focused on the activity itself: If you want to footnote a point RE: land required for all of the processing plants involved in unconventional production here in the U.S., if necessary, that would be fine.

transportation via transmission pipelines (transmission stage), and through combustion in gas-fired power plants (use stage).

Commented [EK183]: NETL Team - 'the use through' was somewhat clunky so I switeched up the text.

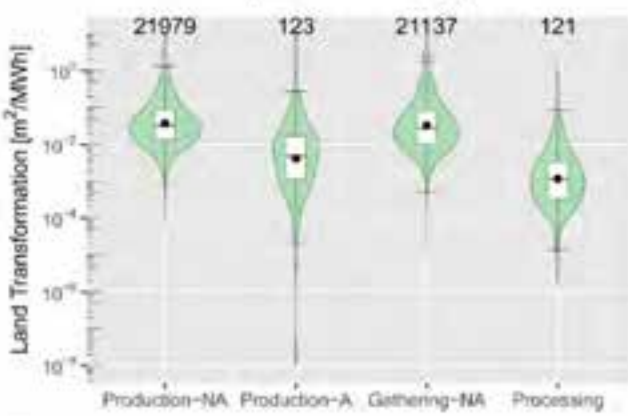
For the production stage, Dai et al. (2023) map land-use for 100,009 wells located at 75,915 different well pads. Among the 100,009 wells examined, 31,716 were co-located. In non-agricultural areas, results suggest vertical wells occupy ~4000 square meters (m^2) less land per site than horizontal-/directional-drilled wells. During the gathering stage in both agricultural and non-agricultural areas, sites with horizontal-/directional-drilled wells, on average require ~230 meters less pipeline in length than sites with vertical-drilled wells, whereas due to the requirement for larger width of right-of-way, the extent of land use is almost doubled for sites with horizontal-/directional-drilled wells. Results from Dai et al. (2023) are summarized in Exhibit 6-1.

Exhibit 6-1. Land use throughout the life cycle of gas-fired electricity

Stage			Unit	Average
Production	Agricultural	Directional	m^2 per site	9,346
		Vertical	m^2 per site	2,100
	Non-agricultural	Directional	m^2 per site	18,170
		Vertical	m^2 per site	14,090
Transportation by gathering	Length	Directional	m^2 per site	597
		Vertical	m^2 per site	818
	Area	Directional	m^2 per site	20,157
		Vertical	m^2 per site	10,128
Processing			m^2 per (MM cubic feet per day)	4,318

Exhibit 6-2 from this study illustrates the land transformation by stage, showing that production in non-agricultural areas utilizes more land than agricultural areas.

Exhibit 6-2. Land transformation in natural gas production



Note: NA = non-agricultural area, A = agricultural area

Used with permission from Dai et al. (2023)

Notably, technological advancements will play a significant role in decreasing the amount of land that will be transformed during the life cycle stages of production, gathering, and ~~[illegible]~~ of natural gas (Dai et al., 2023).

Commented [LBD184]: Suggest a few words explaining how, or possibly delete this sentence.

6.2 HABITAT FRAGMENTATION

The construction and installation of ~~the~~ infrastructure necessary for ~~development of~~ natural gas ~~development~~ can lead to a habitat being converted from a large contiguous patch of similar environments to several smaller, isolated environments. Long-term effects of shale gas production on habitat disturbance will have to be evaluated as the development of these resources continues. Mitigation measures such as avoidance, best management practices, and prompt reclamation of the drilling site have been put forward as ways to best minimize the possible impacts that shale gas production may have on habitats. Habitat disruption can also result from a lack of surface water availability in response to withdrawals to support natural gas production and quality from erosion and chemical spills. The potential water use implications of natural gas are discussed in Chapter 4 – Water Use and Quality.

There are several impacts associated with the development of gas drilling sites and natural gas production that can disrupt the habitat of both plant and animal species. These impacts can arise from a variety of sources and at various points throughout the extraction and production process. Habitat fragmentation occurs when infrastructure must be installed, or land clearing must take place to allow access to a well location. Habitat fragmentation was given as one of the environmental risk pathways that were identified as a consensus priority risk pathway in a survey of 215 experts in government, industry, academia, and non-governmental organizations (RFF, 2013).

When contiguous core habitats are fragmented into smaller patches, many sensitive species are unable or unwilling to cross non-habitat regions to reach alternative habitat patches. While habitat loss can have an immediate impact on wildlife population, the ecological response to fragmentation is lagged, and affects different species at varying timescales (Makki et al., 2013).

A secondary impact of fragmentation is the creation of edges. Edges are generally defined as the 100 meters between core forest and non-forest habitat (PADEP, 2014; Kargbo, Wilhelm, and Campbell, 2010; Johnson et al., 2010). New edges affect the physical or biological conditions at the ecosystem boundary and within adjacent ecosystems (Fischer and Lindenmayer, 2007). Edge effects are believed to be detrimental by increasing predation, changing lighting and humidity, and increasing the presence of invasive species (Johnson et al., 2010).

Exhibit 6-3 provides a schematic depicting the habitat loss and fragmentation from natural gas production. Exhibit 6-3 progresses from infrastructure development that has quantifiable land impacts leading to temporally extended land changes, ~~impacts~~ which account for habitat loss and fragmentation.

Exhibit 6-3. General procedure for depicting land disturbance from natural gas extraction

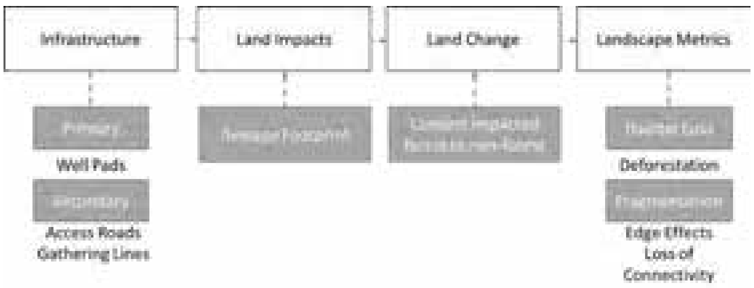
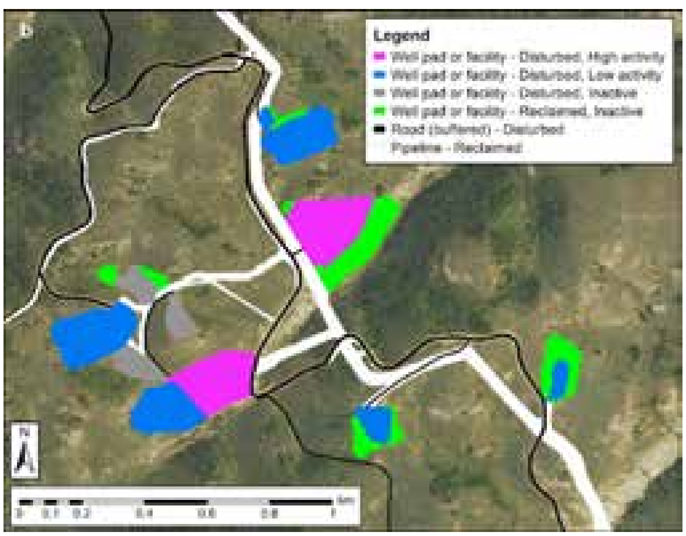


Exhibit 6-4 provides an example of energy infrastructure features digitized from 2013 National Agricultural Inventory Program satellite imagery overlaid with well locations reported in COGCC data. Each mapped feature (or portion thereof) was classified by type (well pad, facility, road, or pipeline) and by surface type (disturbed or reclaimed), and well pads and facilities (or portions thereof) were assigned an activity status (high, low, or inactive) (Walker et al., 2020).

Exhibit 6-4. Footprint of a well pad and surrounding infrastructure



Used with permission from Walker et al. (2020)

Each region where natural gas extraction takes place has unique species and habitat therein~~that inhabit the particular regions~~. Within those species, some are more greatly affected than others, whether it be core habitat fragmentation or~~f~~ edging.

6.3 Noise, Light, and Traffic

Natural gas development processes are associated with both noise and light pollution, which can contribute to stress among those living in nearby communities (Down, Armes, Jackson, 2013; Korfmacher et al., 2013; Peduzzi et al., 2013; Witter et al., 2008a; Witter et al., 2008b). Construction, vehicles, drilling, compressors, flaring, and other processing equipment and facilities can all pollute through excessive noise and continuous illumination (Cleary, 2012).

6.3.1 Noise Pollution

~~The~~ A health impact assessment in Colorado identified noise pollution as an area of concern and noted that it occurs during drilling and completion operations, flaring, and because of~~as a result of~~ vehicular traffic (Witter et al., 2013). Workers can be exposed to noise through many sources on site, including diesel engines, drilling, generators, mechanical brakes, ~~operation of~~ heavy equipment operations, and radiator fans (Witter et al., 2014); therefore, hearing impairment is a noise-related health concern for workers on site.

A biomonitoring study from Texas found residents reporting concerns about odors and noise apparently related to shale gas well and compressor station operations, although this was a separate, independent component from the biomonitoring portion designed ~~in order~~ to address residents' concerns (Texas Department of State Health Services, 2010). While the authors noted that it was difficult to determine if the levels were above acceptable limits that may be harmful to human health, and that noise may affect quality of life, this is speculative because noise levels were not measured to establish decibels of noise in the study area.

Noise standards for a single well pad may be met; however, the cumulative effects of multiple operations in one area might exceed these established decibel levels. In terms of setback distances, some noise regulations distinguish between maximum decibels for day and night, while others distinguish between maximum decibels for certain phases of the operation such as drilling, fracturing, and production; however, there is often variability and, in some areas, it is suggested that distances are set as monitoring points, not necessarily points indicative of being protective of health (Fry, 2013).

6.3.2 Light Pollution

Light pollution has significant implications for the environment and public health, and its effects have become more pronounced over time due to the increasing extent and radiance of artificially ~~-~~lit areas (Kyba, 2017). Substantial economic values have been attached to affected outcomes, such as biodiversity, recreation, and public health. With respect to human health, artificial lights at night are associated with sleep deprivation and mental health (Patel, 2019; Xiao, 2020); sleep deprivation, in turn, has been shown to reduce cognition and labor market productivity, as well as elevate mortality risks associated with dementia, heart attacks, and vehicle accidents (Hafner et al., 2017; Paksarian et al., 2020; Ma et al., 2020; Jin and Ziebarth, 2020; Prats-Uribe, Tobías, and Prieto-Alhambra, 2018.). A study in Australia quantified the financial and non-financial costs of inadequate sleep in 2016–2017 to be $45 B (Hillman et al., 2018) and another study estimates that $680 B is lost due to sleep deprivation across five

Organisation for Economic Co-operation and Development countries (Hafner et al., 2017; Boslett, 2021).

Light pollution also has significant consequences for wildlife populations. It affects nighttime behavior and habits of terrestrial (Bennie et al., 2015) and marine (Davies et al., 2014) wildlife populations, particularly for species that use sun or moon light for guidance. It disrupts natural sleep and reproductive cycles, geographical orientation, and predator-prey relationships (Longcore and Rich, 2004). Other effects of light pollution include changes in bird singing behavior (Miller, 2006), estrus patterns in nocturnal primates (LeTallec, Théry, and Perret, 2015), insect pollination (MacGregor, 2015), and fish biological rhythms (Brüning et al., 2015). These impacts have led to ecosystem-wide changes in biodiversity and growing disparities between entire taxonomic groups (Davies et al., 2013).

The impacts of light pollution also extend to human health and well-being. Artificial light disrupts melatonin secretion and circadian rhythm (Haim and Zubidat, 2015) with corresponding changes on mood regulation, depression, and sleeping disorders (Cho et al., 2016). Light pollution-driven changes in circadian rhythms may also have contributed to recent growth in obesity and metabolic dysfunction (Fonken et al., 2010). Growing laboratory and epidemiological evidence also support the long-hypothesized relationship between nighttime light exposure and cancer rates (Kerenyi, Pandula, and Feuer, 1990; Kloog, et al., 2010; Schwimmer et al. 2014; Jones, Pejchar, and Kiesecker, 2015).

While there is some work speculating that light pollution associated with shale development induces psychosocial stress (Fisher et al., 2017), sleep and mental health issues (Casey et al., 2018), and adverse impacts to local ecosystems (Kiviat, 2013), the literature directly connecting the recent resource boom to light pollution is extremely limited. Importantly, no work has documented the causal impact of U.S. shale development on light pollution.

6.3.3 Traffic Pollution

Traffic may increase in any given area as a result because of unconventional natural gas development, but the magnitude of this increase has not been studied in depth. The phases of development that require the most traffic load involve well pad construction, drilling and well completion, and pipeline construction (Witter et al., 2014). It appears that changes in traffic patterns will be dependent upon the area and either the individual project or the cumulative effects of multiple projects in an area. Industrial truck traffic can be detrimental to health-related air quality due to vehicle exhaust, as well as pose an increased risk of motor vehicle crashes.

In the *Revised Draft Supplemental Generic Environmental Impact Statement on The Oil, Gas and Solution Mining Regulatory Program*, the New York State Department of Environmental Conservation (NYSDEC) identified temporary but adverse noise and visual impacts from construction activity and increased truck traffic among the potential land-use environmental impacts associated with natural gas production (Witter et al., 2014). Significant adverse impacts in terms of damage to local and state roads could also result. Among mitigation measures described for environmental impacts, NYSDEC suggests imposing measures to reduce the adverse noise and visual impacts from well construction. A transportation plan could also be

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required that would include proposed truck routes and assess road conditions along the proposed routes. Exhibit 6-5 tabulates the number of truck trips for a typical shale gas well (Massachusetts Institute of Technology [MIT], 2011).

Exhibit 6-5. Truck trips for a typical shale gas well drilling and completion

Activity	1 Rig, 1 Well	2 Rigs, 8 Wells
Pad and Road Construction	10–45	10–45
Drilling Rig	300	60
Drilling Fluid and Materials	25–50	200–400
Drilling Equipment (casing, drill pipe, etc.)	25–50	200–400
Completion Rig	15	30
Completion Fluid and Materials	10–20	80–160
Completion Equipment (pipe, wellhead, etc.)	5	10
Fracturing Equipment (pump trucks, tanks, etc.)	150–200	300–400
Fracture Water	400–600	3,200–4,800
Fracture Sand	20–25	160–200
Flowback Water Disposal	200–300	1,600–2,400
TOTAL	1,160–1,610	5,850–8,905

The large volumes of water involved in hydraulic fracturing operations can create high volumes of road traffic given the majority of the water used for fracking~~turing~~ is transported by truck. It should be emphasized that the large number of traffic movements shown in the table above are worst-case estimates. In particular, re-use of flowback wastewater significantly reduces the amount of road traffic associated with hauling water, which represents much of the traffic movement. Furthermore, large-scale operators are also using pipelines to transport water to the site, substantially reducing the amount of road traffic (MIT, 2011).

The Eagle Ford Shale Task Force Report for the RRC identified increased traffic and deterioration of roads and bridges among the infrastructure impacts from shale gas development (Porter, 2013). Exhibit 6-6 lists estimates of the number of truck-trips-per-shale-gas-well in the Eagle Ford (Porter, 2013).

Exhibit 6-6. Loaded truck trips per gas well

Activity	Number of Loaded Trucks
Bring well into production	1,184
Maintain production (per year)	Up to 353
Re-fracturing (every 5 years)	997

These impacts are enough of a concern that the task force considered alternative financing methods to help meet the increased demands on roads and bridges (Porter, 2013).

Upadhyay and Bu (2010) surveyed the visual impacts of Marcellus drilling and production sites in ~~PA~~Pennsylvania. They reviewed the drilling process, assessed direct visual impacts, and compared the results to the impacts of other technologies (e.g., windmills and cell towers). They also studied drill-pad density from map and aerial perspectives to examine the likelihood of seeing drill towers across a landscape, and the modeled potential impacts for increased drilling, making the following conclusions:

- Serious impacts from light and noise are a potential problem within a small radius of drilling sites.
- Indirect impacts like increased truck traffic, equipment storage, and temporary structures compose the most salient visual impacts, rather than the drill pads themselves.
- Timelines for site restoration of visual impacts vary significantly.

Upadhyay and Bu (2010) recommended that visual impacts be addressed during the siting and design phase and that nighttime impacts could be avoided by pointing lights downward.

The RFF (2013) report also gave several options in their survey of experts under the category of community disruption. Included in this category, as well as in the habitat fragmentation section, were such risks as light pollution, noise pollution, odor, and road congestion. The industry respondents identified a number of these community disruptions as risk pathways of high priorities, while the other respondent groups identified more conventional (e.g., air pollution, water pollution, etc.) risks.

6.4 Regulations and Strategies to Reduce Land Impacts

While there are very few regulations to reduce the impacts on land, habitat, noise, light, and traffic pollution, best practices have been developed in some cases.

6.4.1 Mitigation Options for Habitat Fragmentation Impacts

The NYSDEC (2011) study proposed that, if the development area included a region of continuous forest over 150 acres in size or a region of grassland over 30 acres, an ecological assessment should be conducted to identify best management practices.

A 2012 study of hydraulic fracturing practices in the Inglewood oil field in California, operated by the Plains Exploration & Production Company, proposed that the best way to mitigate habitat fragmentation impacts is to adopt best management practices, perform wildlife surveys, and implement restrictions during migration and mating seasons (Cardno ENTRIX, 2012). The study also found that ensuring that well pad reclamation occurs is the most productive method to reduce harm to populations (Cardno ENTRIX, 2012).

Avoiding disturbances to sensitive areas such as wetlands, waterways, and wildlife habitats when locating drilling sites could be the best method for mitigating impacts. Reclaiming the land upon completion of drilling activities is the best way to mitigate impacts in those cases when avoiding disturbances is impossible (NETL, 2009). Proceeding with reclamation processes as quickly as possible can minimize the disturbances, but all mitigation measures (including

avoiding disturbances to begin with) are subject to the landscape, plants, and wildlife that are present at a site.

The Western Governors' Association (2006) released a handbook outlining the best management practices for CBM development to be shared among the Association's shareholders. The practices are split into multiple categories, including planning, water, landowner relations, and infrastructure. Several subcategories can be applied to mitigating habitat fragmentation, such as protection of wetland areas, roads and transportation, pipelines and power lines, habitat and species protection, and wells. To protect wetland and riparian areas, facilities such as well pads should be sited outside of such regions as much as possible, and features that cut across the landscape, such as roads and pipelines, should avoid crossing wetlands and riparian areas as much as possible (Western Governors' Association, 2006).

Best practices for mitigating disturbance from roads and transportation include keeping road development to a minimum, using existing access roads as much as possible, using unimproved roads as little as possible during wet weather, following road construction and maintenance standards, avoiding sensitive areas, and attending to safety issues and other problems (Western Governors' Association, 2006). Recommendations of best practices for pipelines and other lines include using existing pathways, installing as many lines as possible in a single location, and using the least invasive construction equipment possible. To protect habitat and sensitive species, lines should be buried rather than installed above ground if possible. Well sites should minimize the amount of surface disturbance that occurs and should be reclaimed as quickly as possible upon completion of development activities (Western Governors' Association, 2006). Again, these best management practices have been developed in areas of CBM production by the Western Governors' Association, but many of these practices are applicable to shale gas development.

Drilling on federal or public lands is subject to oversight by federal agencies, and sections of the Endangered Species Act may require that species of plants or animals not be threatened by the permitted drill site (NETL, 2009). Mandatory plans for mitigation and reclamation may be required to ensure that impacts on wildlife and habitat will be as minimal as possible (NETL, 2009).

With approximately 33 units of the National Park System in or near the Marcellus Shale, NPS found it important to be informed and current with development issues. Moss (2012) provides an overview of the geology, technology, current activity, and potential environmental impacts. Among the effects described are widespread development and well spacing, site space needs, water use, aquifer contamination, air quality, and truck transportation. There are then four recommendations to help park units prepare for potential shale gas development on and around NPS lands (Moss, 2012):

1. Check land and mineral ownership – Know if private in-holdings or private or state mineral estate underlie an NPS unit.
2. Be aware of industry interest adjacent to park boundaries – Land speculation, exploration, or drilling could signal increased requests for drilling permits. Contact the state oil and gas agency to express concerns and issues.

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3. Work with state agencies – Meet with the state permitting agency, establish agreements, engage with stakeholders before issuance of permits, and if possible, have protective mitigation measures included directly in the lease.

The NPS Geologic Resources Division assists parks with policy and technical issues and reviews permitting and environmental documents to help mitigate or eliminate adverse impacts (Moss, 2012).

In January 2013, the BLM updated a presentation detailing best management practices for wildlife management that can help to minimize habitat fragmentation. The document offers several practices that can be implemented or planned to lessen impacts on habitat. The well pad itself and the immediate surroundings can be fit to the space available to minimize the disturbed area, rather than constructing a generic rectangular pad (BLM, 2013). There are also multiple examples of reclamation practices, both at the drill site and on access roads, that can be implemented to lessen the impact of the infrastructure. The well pad and supporting infrastructure (roads, pads, storage, and pipes) can be designed to be as efficient and minimally obstructive as possible (BLM, 2013). Wells can be remotely monitored using telemetry, pipelines and other lines can be buried where possible, and any existing corridors for roads and lines should be used whenever possible (BLM, 2013). It is helpful to monitor local wildlife populations to ensure that mitigation and reclamation measures are effective, and final reclamation upon abandonment of the well is critical to the long-term effectiveness of mitigation options (BLM, 2013).

6.4.2 Reducing Light Pollution

Even two decades after the establishment of designated programs by non-government organization(NGO)s to recognize and certify the quality of night skies and nighttime darkness resources, the very notion of what a "dark sky" is remains unsettled from a scientific standpoint (Crumey, 2014); while appropriate instrumentation can quantify night sky brightness, it cannot properly account for the human aesthetic experience of natural night. However, various lines of research increasingly suggest that unsafe thresholds of exposure to artificial light at night in terms of intensity, duration, wavelength, and timing likely exist for humans, plants, and animals. In this sense, light-sensing technologies applied in the field could effectively serve as "dosimeters" for monitoring these exposure parameters (Barentine, 2019).

6.5 DOE Research and Development and Analysis

An independent review of the literature suggests there is currently no or analysis with respect to land use, habitat fragmentation, or light, noise, or traffic pollution being conducted by DOE.

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7 Social Justice and Natural Gas/Liquefied Natural Gas Market Development

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7.1 Introduction

Granting authorizations to import and/or export natural gas into and from the United States could potentially generate and, in some cases, ~~further~~ contribute to perpetuating~~e~~ instances of energy, environmental, and social injustice. Conversely, if potential impacts to disadvantaged and frontline communities[a] are both carefully considered and minimized, then opportunities to advance environmental, energy, and social justice may also be present. Ensuring the advancement of energy, environmental, and social justice across the domestic natural gas market, however, requires meaningfully engaging historically disadvantaged and frontline communities and ensures exposure to harms or burdens for these communities are prevented and minimized.

These types of considerations have driven the implementation of the Biden-Harris Administration's Justice40 initiative that was mandated under Executive Order 14008, and which has an explicit goal that 40 percent of the overall benefits from federal investments should flow to historically disadvantaged and disenfranchised communities and communities burdened by pollution. Specific types of projects include those related to the clean energy transition both in energy production and the advancement ~~for~~ of net-zero emission transportation. Additional categories include affordable housing and "green" workforce development and training, as well as those focused on ~~the~~ remediation of legacy pollution, clean water initiatives, and wastewater projects. Introducing the Justice40 (2023) framework to the ways in which government measures the distribution of investment benefits attempts to right the historical wrongs that have resulted in the unequal outcomes seen today by requiring the success of projects to be measured according to whom the benefits and burdens are distributed.

This chapter seeks to summarize the incorporation of social, environmental, and energy justice concepts found in the broader research literature as they relate to natural gas and LNG market development. The goal is to summarize what already exists and provide guidance as to how future research might be pursued at the nexus of social, energy, and environmental justice and project development. This literature review specifically focuses on the development of large-scale energy infrastructure intended to supplement the energy-transition goals outlined by the current administration and its policies. However, the challenge (and opportunity) researchers face in this space is rooted in the relatively less robust focus that has been spent on applying energy, environmental, and social justice concepts to the development of energy infrastructure projects specifically for natural gas and LNG markets.

Commented [LBD193]: Is it a goal of this document to map out future research? My current understanding of the purpose of this update is to provide information on potential impacts of unconventional natural gas.

[a] Per the National Oceanic and Atmospheric Administration (NOAA), frontline communities are "those who are the most vulnerable to and will be the most adversely affected by climate change and inequitable actions because of systemic and historical socioeconomic disparities, environmental injustice or other forms of injustice" (NOAA, 2023).

Due to the nascency of research that links social, environmental, and energy justice issues with the development of natural gas and LNG markets, this literature review will cover research that has already connected these issues and weave together the separate literature areas into the discussion. For reference, this review uses the structure presented in Spurlock et al. (2022) that outlines a tractable framework to incorporate energy justice tenets into energy infrastructure planning decisions and deep decarbonization policy implementation strategies.

This discussion is further framed as a struggle to balance energy justice issues rooted in the unequal exposure to pollution and related burdens with the need to resolve where communities do not have equitable access to clean, affordable, and reliable energy. This chapter concludes by underscoring the idea that incorporating energy justice tenets (distributional, procedural, and recognition) must be done from the big-picture view of energy project governance as it is the point where all project planning, development, and implementation is most directly influenced. It is from the point of governance that the effort to ameliorate energy poverty through the implementation of environmental and energy justice can produce a just transition away from a GHG-intensive economy and toward a more sustainable outcome.

7.2 Distributional, Procedural, and Recognition Justice

The three core tenets of energy justice are the assurance of distributional, procedural, and recognition justice, as shown in Exhibit 7-1 (Spurlock, Elmallah, and Reames, 2022). To aid in the understanding of the bigger picture of energy justice, the following subsections provide background on these three tenets.

Exhibit 7-1. Flow of energy justice decisions

Permission pending from (Spurlock et al., 2022)

Commented [RK194]: While the application of a justice framework to this energy context is conceptual - there is a robust literature on socioeconomic and community impacts of UOG development in the last ten years. Will share a separate doc with recommendations.

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Commented [BO196R194]: I think these recommendations on the impact of development efforts may be better suited to the follow-on effort to this chapter referenced by Tom Curry in Friday's call. They synch up with some of his descriptions of Natenna's recommendation that were more about the next logical extension of a chapter like this.

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7.2.1 Distributional Justice

Distributional justice is focused primarily on the equitable distribution of benefits and dis-benefits across communities (Spurlock et al., 2022). It is a concept focused on the well-being of individuals, which spans the gambit of human outcomes such as psychological well-being, societal well-being, and physiological well-being (Deutsch, 1975). Distributional justice delves into the nuanced context in which equity versus equality versus need may dominate in identifying unjust distributions.

Fairness is a key concept within distributional justice and can be characterized as a problem for geospatial analysis (Bouzarovski and Simcock, 2017). Across the energy supply chain, distributional justice is a problem of implied risk responsibility as well as costs and benefits (Heffron and McCauley, 2014). In addition to inequities created by a historical lack of inclusiveness is the risk that those structural deficits will compound under a changing climate. In other words, unless addressed, the deficits of the past will likely increase as the climate changes much like a revolving line of credit tends to grow faster over time when a balance is carried from one period to the next.

7.2.2 Procedural Justice

Spurlock et al. (2022) present procedural justice as essentially the effort to include all voices. This is the idea that disadvantaged communities are overburdened and underserved and their disenfranchisement can only be corrected when their voices are intentionally included in the start-to-finish process of project and policy development. In other words, stakeholder engagement must be done early and often to ensure the priorities of disadvantaged communities are codified in the priorities of the project or policy.

Procedural justice takes a more holistic view of outcomes from the perspective of group perception. Researchers break the impacts of procedural justice into three areas of effect: voice, dignitary process, and fair process. The voice effect is the positive behavior observed in communities engaged with a decision-making process when the individual feels heard. The effect of dignitary process is best described as respect. When an individual's dignity is preserved, the community buy-in to the procedure grows. Finally, the fair-process effect describes the positive community behaviors that arise when the group perceives the existence of procedural justice. In a sense, the effect of fair process augments the effects of the dignitary process and the power of voice (Lind and Earley, 1992).

7.2.3 Recognition Justice

At its core, recognition justice deals with respect and consideration. Spurlock et al. (2022) present the concept as a demand to recognize that divergent views exist on the best pathways for energy project development and strategies to address issues of climate justice. Those views reflect the unique, diverse backgrounds of these communities who present the perspectives and opinions reflective of their histories. Incorporating those voices in the energy transition is critical to ensuring policymakers implement project development that seeks to serve all.

Equitable outcomes begin with the recognition that disenfranchised communities will require effort to enfranchise and empower their members to ensure their histories and perspectives are heard in a meaningful way.

Recognition justice seeks to provide for fair representation, safety, and the general creation of an environment that is welcome to all. McCauley et al. (2013) identify issues of recognition injustice in terms of how policy might treat those characterized as "energy poor" with the classic example of the behaviors of elderly household energy use. Looking at the overall higher average energy use, United Kingdom policymakers view the issue as an education problem where the assumption was that elderly people do not understand the long run impacts of small behavior changes. The authors reveal that framing choices in way that nudged elderly households toward the intended policymaker outcome required acknowledging that older people need warmer houses for their health and well-being. Strategies for changing behavior are more effective when normative behaviors within the community, culture, or ethnicity are recognized.

7.3 ENERGY JUSTICE

Anchored by the three tenets of distributional, procedural, and recognition justice, energy justice acts as a guiding concept for activism (McCauley et al., 2013). A broad literature review on the topic of energy justice (Qian et al., 2022) shows that the recent growth and focus on energy justice has quickened in pace with the effort to incorporate renewable energy on the electric grid. Debating the definition of energy justice has been a robust area of discussion for researchers, but there exist a few core concepts that underpin most approaches. At its heart, assuring that energy justice deals with the issue of ~~addressing~~ energy poverty and branches out from the broader focus of environmental justice (Iwińska et al., 2021).

While focus on the justice of energy distribution is not new, it has grown in salience as the public increasingly accepts the need to transition from fossil fuels-based systems of energy production and consumption to clean alternatives. Using energy justice as a decision-making framework, Iwińska et al. (2021) outline the focus of this literature as one that seeks to consider how the policy-making framework surrounding the generation and consumption of energy can be fairer. In this sense, energy justice acts as a tool, helping to guide policy design.

On one hand, Iwińska et al. (2021) consider the energy justice concept as a "boundary object" whose conceit is to accelerate the inculcation of these principles in policymaker innovation and across all cultural boundaries—much like a change agent. On the other hand, these authors debate the merits of treating the concept as a standard rather than a boundary object. Standards on energy justice would more easily be incorporated into policy in tractable forms that are quantitative and qualitative, though likely at the loss of a unifying definition (Iwińska et al., 2021).

Digging beyond the core tenets of energy justice, Sovacool and Dworkin (2015) acutely characterize the conceptual metrics by which broader approaches to energy justice may be measured. Those include the need to measure the costs communities face with a special emphasis on the level of inequity across communities relative to the distribution of these costs. Sovacool and Dworkin (2015) also identify the need to distribute benefits to these same

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communities. Though it seems logical to measure the costs *and benefits* to disadvantaged and disenfranchised communities, historical focus has more often been on mitigating or compensating losers for costs rather than on how project design can seek to benefit disenfranchised communities. Their very disenfranchisement may relegate them to an after-the-event consideration (when considered at all), which highlights costs over benefits. The simple statement that benefits should be considered alongside costs may act to nudge the focus back toward before-the-event planning.

Sovacool and Dworkin (2015) list procedure as the critical element that can act to bridge the cost-benefit gap. The process by which energy project development flows can be exclusive by nature; this would naturally prohibit the participation of disenfranchised communities who, again by definition, are not empowered to advocate as robustly as the enfranchised communities.

Iwińska et al. (2021) outline the various foci of energy justice research. The current dominant topic has been renewable energy, as energy transition efforts have driven the growth of interest in energy justice. Summarizing the remainder of the subtopics of energy justice in broad terms, the research falls within the categories of energy poverty, energy policy, law, and governance.

Results from the transition away from fossil fuels are producing differentiated outcomes that vary by community. Energy justice studies reveal that some communities are clearly benefiting from the increased access to renewable energy technology and opportunities while others assume the burdens of change. Those communities that seem to be accruing the adverse health outcomes and increased cost of cleaner technology are the same historically disenfranchised peoples who often fail to reap the job gains and regional economic growth opportunities of change. Beyond this, the transition away from fossil fuel production harms local governments' ability to provide constituent services in cases where fossil fuels are dominant sources of economic activities. Nonprofit organizations tend to lead in the effort to ameliorate these inequitable outcomes (Carley, Engle, and Konisky, 2021).

Commented [RK201]: One aspect about the transition away from fossil fuel production relates to dependence of fossil fuel revenues, fiscal policy, and consequences to public service and infrastructure provision.

Pellegrini-Masini, Pirni, and Maran (2020) make the case that the prevalence of energy justice definitions inhibits the capacity of policymakers to deploy these concepts toward the greater good. They highlight several useful but nuanced approaches with Guruswamy (2010) underscoring the "energy oppressed poor" as those suffering from an inequitable distribution of energy as a resource, which is innately about distributional justice.

7.4 Energy Poverty and Energy Burden

Poverty is a dominant issue that arises often in research focused on energy. As policies are implemented to attenuate the worst effects of climate change, the focus on carbon emissions as a flow and stock[g] necessarily highlights how these costs are going to be born geospatially.

[g] The term "greenhouse gases" refers to those associated with atmospheric warming; however, GHGs are not uniform in how they affect the global warming process as their lifecycles vary. Carbon dioxide is considered a stock gas as it remains in the atmosphere for long periods. As such, it builds up over time like a "stock" of gas. CH_4 is a much shorter-lived GHG. It enters the atmosphere and remains for just about 12 years. As such, it is considered a gas that "flows" through the atmosphere with short-lived warming impacts for any one unit of methane.

Carbon mitigation policies themselves also present societal costs that are unequally burdening communities based on how much of the remaining carbon budget impoverished communities might need. But at its heart, energy justice is an issue of economic opportunity as access to safe, affordable energy is a necessity to meet basic human needs and pursue economic growth opportunities (Piwowar, 2022).

Bouzarovski and Petrova (2015) identify the criteria and conditions that drive energy poverty as the material and/or social deficit in energy services accrued by communities. The authors outline two key issues. First, deficits in domestic energy access and supply are the direct result of ineffective socio-technical mechanisms that fulfill energy demand at the household level of energy services such as heating and lighting. Second, "vulnerability thinking" often drives or exacerbates these outcomes. That is to say, the perceived likelihood of becoming impoverished can drive outcomes, frame processes, and generally lead to the undesired outcome as a result of historical perceptions or perspectives (Hall et al., 2013).

Okushima (2021) attempts to measure the "basic carbon needs" of a community. These are the total GHG emissions an individual community might bare to attain an "adequate level of domestic energy services." Okushima's case study of Japan highlighted that basic carbon needs varied based on differences in several factors within a community including the type of domestic dwelling, community demographics, and variation in climate characteristics across regions. Affluence allows people to shift away from GHG-intensive energy sources and can change basic carbon needs. Moreover, Okushima (2021) found that balancing the ability of all communities to meet their energy needs with decreases in their basic carbon needs is the critical factor for achieving some equitable progress on climate change.

The importance of energy poverty may have increased in recent years as a function of the world's increased attentiveness to climate change risks, but Campbell (1993) points to the 1970*s* oil crises as the flux point at which energy poverty challenges to political stability were revealed. Those latent risks to social cohesion were evident in communities dominated by lower incomes, access to inefficient heating technology, and sub-standard governmental guidelines for housing insulation. However, the sudden rise in oil prices catalyzed those latent risks into active disruptions that were exacerbated as policymakers introduced mechanisms to ration supply.

Campbell (1993) identifies the conceptual term "poverty" as an issue that confounds action on the problem of energy poverty. Poverty is identified as a multi-generational condition that permeates at the community-level without tangible points of action to take. To most, the state of poverty is a state of being. This is a challenge without boundaries—that formlessness tends to overwhelm policymaker action especially when considering the issue as multi-generational. Measuring those impacts on a quantifiable level is, therefore, a distinct challenge.

Energy poverty, on the other hand, is an energy infrastructure problem that capital expenditures can directly cure because household expenditures on fuel are quantifiable; therefore, a threshold exists in theory where energy poverty begins and ends (Campbell, 1993).

Campbell points to Boardman (1987) who posited that 10 percent of one's household income being spent on energy/fuel was the threshold of concern for energy poverty—a metric adopted by several others (Green et al., 2016; Lloyd, 2006; Lesser, 2015). While a large proportion of research identifies that spending above 10 percent indicated a state of energy poverty whereupon the cost of fuel consumption to meet one's energy service needs was a burden, some researchers have illustrated that threshold is 6 percent (Drehobl et al., 2020).

Follow-on research has expanded on this effort to measure energy poverty by creating a metric of threshold for energy poverty. While some countries have adopted specific metrics for measuring and comparing energy poverty (Faiella and Lavecchia, 2021), there is no clear consensus on best practices. Chapman and Scannell (2005) developed the Affordable Warmth Index based on the calculation of energy ratings to identify sources of energy that need efficiency investments by policymakers and households. Several others have made contributions, for example, Siksnelyte-Butkiene et al. (2021), Thomson and Snell (2013), Heindl (2013), Miniaci et al. (2014), Okushima (2016), and Brunner, Spitzer, and Christanell, (2012).

Regardless of the methodology for measuring energy poverty, the fundamental issue at hand is that the lack of affordable warmth changes people's basic daily routines. The onerous nature of accommodating these energy deficits tends to drive health and wealth outcomes for households (McCrone, 2015). The lack of affordable energy can bind communities to a lack of economic opportunity as they attempt to accommodate for energy deficits or their high costs, which tend to affect minorities and people of color more intensely.

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The myriad impacts of energy poverty on health are too numerous to cover in this document, but Faiella and Lavecchia (2021) outline several. Overall, households with limited incomes are energy poor and suffer from subsequent negative health outcomes (Thomson et al., 2017), for example, excess deaths during wintertime (McAvoy et al., 2007) with the elderly particularly at risk (de'Donato et al., 2013) and increasing seasonal variation due to climate change compounding these risks (Healy, 2003). For healthcare systems, this increased seasonal health risk can reduce economic activity and reduce the integrity of the broader healthcare system (Wells, 2007) with compounding effects to the system over time (Torjesen, 2012).

Negative outcomes tend to accumulate across multiple community contexts, but their effect is not felt in isolation. Rather, these negative community outcomes tend to have cumulative effects that interact and compound each other with the risk of cointegrated impacts higher with LNG project development (Gislason and Andersen, 2016).

7.5 Just Energy Transitions

The current energy transition presents a generational opportunity to make significant progress in ameliorating historical injustices (Wang and Lo, 2021). As technology has evolved and capital has flowed into large-scale energy infrastructure investments, a concerted effort to accrue the economic and social benefits associated with these technologies and investments in disadvantaged communities may prove fruitful in spurring a more just outcome from the energy transition. Equally possible is the ability to start mitigating the systemic injustices that have continued to plague these same communities in response to historical decision-making.

The articulation of energy transition goals varies significantly across the research literature, but it tends to boil down into a handful of broad topics.

These include poverty reduction (Lo and Broto, 2019; Koehn, 2008; Colenbrander et al., 2017), amelioration of historical energy injustices (Jasanoff, 2018; Delina and Sovacool,2018; Carley and Konisky, 2020), and opportunities for economic growth (Yang et al., 2018; Ehresman and Okereke, 2015). Wang and Lo (2021) argue that the energy transition is an apt vehicle for fixing historical wrongs if it can simultaneously account for environmental costs disadvantaged communities already suffer from, the reality that climate change will likely exacerbate these pre-existing environmental costs, and a decision-making process steeped in the tenets of assuring energy justice.

Pellegrini-Masini et al. (2020) attempt to prioritize the approach toward justice and the energy transition across four planes. First, the tradeoff in intergenerational outcomes and opportunities must be a prominent consideration for policymakers. This addresses the core reason that mitigating climate change is essential: subsequent generations should be provided the opportunity for growth and well-being that is at least commensurate with today's generations. Second, building out policy that considers energy vulnerability will help to prevent the transition from being a zero-sum game in which regional, fossil-fuel-reliant economies are left behind. In this sense, energy projects will benefit vulnerable communities. Third, transforming the social self-image of communities whose cultural identity is tied to fossil fuels must be considered to avoid confusing the energy transition with an attack on disadvantaged communities. Finally, the unavoidable damage to local communities must be accounted and compensated.

The ability to move forward into a new energy landscape that is sustainable is a direct function of the ability of policymakers to avoid repeating historical injustices; justice frameworks must be the bedrock of transition planning (Wang and Lo, 2021; Williams and Doyon, 2019). Pai, Harrison, and Zerriffi (2020) provide the framework for researchers to consider strategies for a just transition—one that preserves the well-being of fossil-fuel-reliant communities. Preserving the human capital of these communities is a critical goal for ensuring the energy transition policy provides opportunities for all. Pai, Harrison, and Zerriffi (2020) summarize more than a dozen requirements that would facilitate policymaker efforts to ensure a just transition but underscore one: the requirement of intentional effort for long-term planning with routine efforts to conscientiously engage with affected communities. Historically disenfranchised communities of people must be actively welcomed into the discussion early and often to be re-franchised and ensure their voices are heard (Weller, 2019).

7.6 Fossil Fuel Employment and Revenue

As the United States shifts away from a GHG-intensive economy, the delicate issue of fossil fuel unemployment arises. Specifically, the risk of unemployment rising as a result of the shift away from a GHG-intensive economy is pronounced in regions where fossil fuel and other extractive-based or refining industries have historically dominated available employment opportunities and been the core driver of local economic growth in the region. The loss of those jobs represents a significant loss to local government revenues, long-term declines in the economy, and a potential cycle of population loss under which the region cannot recover.

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The capacity to politicize energy transition debates is high (Healy and Barry, 2017) with GHG-intensive firms in a unique position to rally action against clean-energy projects (Goods, 2022) as a tradeoff between employment and climate policy. There is some merit to this concern from the community perspective as well. Female employment in the solar industry lags far behind male employment (Carley and Konisky, 2020) and disadvantaged or disenfranchised communities tend to bear a larger overall burden of costs even those associated with cleaner energy projects (Brock et al., 2021). To the extent that governance strategies can acknowledge the dignity of historically disadvantaged communities and groups, efforts to engage with those communities and groups in energy transition and governance strategies will be more successful and less divisive (Grossmann and Trubina, 2021).

Unions are viewed as an amenable structure for elevating and empowering the voices of disadvantaged communities in the energy transition (Pai, Harrison, and Zerriffi, 2020; Newell and Mulvaney, 2013). One reason may be in the high unionization rate of fossil-fuel industries (Pai and Carr-Wilson, 2018). Engaging with unions is in many ways a matter of practicality and the pre-existing internal structures built to advocate for their members make unions a strong vehicle for working toward a just transition[q] (Stevis and Felli, 2015). As an expansion of natural gas/LNG U.S. export capacity could limit the loss of employment for communities historically reliant on the fossil fuel industry, there exists an implicit advantage to directly approaching unions as potential enablers of cooperation with communities. Avoiding the mass loss of employment would help these communities from further decline as they tend to be areas in which the negative health and social impacts of fossil fuels are particularly pronounced.

Intentional efforts to diversify local economies would increase the resilience of local economies (Lobao et al., 2016). Notably, increasing the diversity of local economies is a positive regardless of the effort to transition away from fossil fuels. Any local economy highly dependent on one industry—particularly when that industry is as volatile as extractive-based industry—would introduce a greater resilience supportive of regional growth (Freudenburg and Gramling, 1994).

Among the opportunities a just transition presents are the ability to reduce the gender gap in regions dominated by the fossil fuel industry, increase investment into local energy infrastructure, remediate historical environmental damage, retrain the local workforce to "skill up" the region's human capital, and shore up local government revenues through economic diversification (Pai, Harrison, and Zerriffi, 2020).

In the end, just transitions are achieved when local voices are not just heard but amplified during the energy transition process. An unfortunate trend can play out that misses the mark on this issue where well-intentioned decisionmakers attempt to prescriptively advocate on behalf of disadvantaged communities. Often, policymakers advocate for the environmental protection of disadvantaged communities while neglecting to consider the calls for economic development emanating from those communities. A key example of that rests in the Canadian arctic where LNG projects that could act as local development opportunities for increasing local incomes are prevented by national policies that have banned energy projects out of the best intentions (Nicol and Barnes, 2019).

[q] The term "just transitions" originated within community-organizing efforts centered on labor unions (Eisenberg, 2018).

One obvious benefit of large-scale energy project development rests in the rents accrued from the project's completion. Treating these project benefits as a viable source of income that could be distributed to disadvantaged communities was explored in Chandrashekeran (2021), who studied indigenous populations in Australia after land repossession within Aboriginal populations. Chandrashekeran (2021) found that establishing property rights for historically disenfranchised populations is a key step in empowering collective negotiations for revenue sharing to fund reparations.

7.7 Protests and Political Activism

Excluding communities from decisions creates risks not just for disadvantaged populations, but for the completion of large-scale energy project development overall (Temper et al., 2020). The perpetuation of community disenfranchisement leaves people with a sense that the only option available for advocacy is to organize and protest. The way in which narratives are framed matters a great deal with respect to facilitating community buy-in for policy seeking to pivot away from fossil fuels.

Janzwood and Millar (2022) argue that the duality of natural gas—that it simultaneously accelerates the transition as a baseline electricity input and ensures the perpetuation of GHG reliance—creates the conditions for interpretive politics to dominate discourse around the transition. This is especially true for LNG organizations planning large energy infrastructure projects (Korkmaz and Park, 2019) and when regional economies are reliant on fossil fuels or the topic of natural gas as a "bridge fuel" is debated (Cha, 2020).

On the other side, anti-coal and anti-gas advocacy groups proved their own capacity to organize effectively in developed economies (Durand and Keucheyan, 2022). Social movements such as a the "UK Rights to Warmth" in the United Kingdom coalesced around the fight against entrenched energy poverty to some success (Walker and Day, 2012). Successful efforts to stop LNG export projects were found even in fossil fuel-friendly U.S. states such as Texas (Garrett and Sementelli, 2021) with access to social media and the strategic deployment of online networks increasing their efficacy (Correa-Cabrera et al., 2022).

The willingness to protest varies across cultures. Whereas communities within the United States that are at risk of job losses from national policies might tend to view justice as a regional tug of war that *must be* fought, research into Chinese activism shows that the Confucian perspective on justice as a collective outcome (whose goals are harmony between nature and humanity) shifts the perspective of the debate at its core (Wang and Lo, 2022). However, a nation or region's reliance on fossil fuels is not a reliable indicator of attitudes toward natural gas and LNG projects. Case in point, protestors in Canada and Norway have vehemently advocated against the expansion of oil and gas exploration despite their deep reliance on oil and gas production for both economies (Harrison and Bang, 2022). It has also been found that protests can arise in areas where there is a history of oil extraction when unconventional natural gas exploration is proposed (Chailleux et al., 2018).

The politicization of energy infrastructure can result in starkly divided factions, but the common thread of discontent that binds pro-gas and anti-gas contingencies is rooted in process.

Specifically, deficits in procedural and distributional justice tend to increase the likelihood of activism (Evensen, 2018; Temper et al., 2020).

7.8 Energy Governance and Adaptive Management

Governance structures play a vital role in the pursuit of energy project development and the transition away from fossil fuels, but their ability to provide an equitable or just transition is not guaranteed (Moss, 2009). Incorporating the concept of just outcomes begins with the governance structures of energy project development and planning (Newell and Mulvaney, 2013). Those who are in the position of governance are in a position of authority to inculcate more equitable outcomes to benefit disadvantaged populations (Florini and Sovacool, 2009).

As Florini and Sovacool (2009) point out, governance is not simply government. While governance is an activity in which governments participate it exists as a framework for creating and maintaining processes to implement policy. This framework is the conduit for participation that brings together government, intergovernmental organizations, private sector market participants, and communities to collectively manage a process that ideally serves all groups.

Governance is necessary as a result of two issues with which economists often wrestle. One issue is that society is not capable of ensuring equitable access to public goods without some overarching set of rules to facilitate that outcome and a governance structure to provide oversight over implementation. The second issue is that any economic or social activity tends to create what economists call “externalities.” That is, there are unintended results that can occur indirectly from the consumption of goods or social interactions. The decommissioning of a coal power plant is a prime example of the need for governance to protect the public’s well-being from externalities, as an idle power plant could become the source of negative health outcomes for a community without intentional efforts to prevent such outcomes. Governance structures are necessary to deal with these two conceptual issues because there is no economic incentive to do so (Florini and Sovacool, 2009).

Perspectives can clearly vary within communities and that variation can affect governance structures (Wang and Lo, 2021). In studying international natural gas markets, Norouzi (2022) notes that the heterogeneity of individual members within a collective community implies that international natural gas market outcomes are heavily influenced by individual preferences within any collective. Community engagement is important, but it is not the magic elixir that solves the problem by itself. Ciplet and Harrison (2019) identify three conflicts that emerge in efforts to facilitate an energy transition: 1) between inclusivity and sustainability where inclusive processes that invite community engagement require more time to complete projects; 2) between sustainability and the need to recognize the unique value system for each community, which increases the complexity of sustainability goal pursuits; and 3) between equity and sustainability, meaning that the distribution of costs and benefits can conflict with project performance.

The impact of a region’s political economy can also clearly drive outcomes. Inequality is a multi-dimensional concept that varies across countries and individuals (Laurent and Zwickl, 2021). As the communist states of the Eastern Bloc exited the Union of Soviet Socialist Republics, the effort to integrate into energy markets within the European Union revealed that variations in

culture and geography dominated some preferences in energy project outcomes with respect to energy justice (LaBelle, n.d.). On the other hand, a study of sub-Saharan African nations revealed a positive relationship between democracy, energy justice, and growth (Opoku and Acheampong, 2023). Cultural differences aside, income and wealth inequality may drive many of the outcomes. Studies of European Union attitudes toward sustainability policies show that 41 percent country-level variance in negative attitudes is correlated with differences in wealth and income (Pellegrini-Masini et al., 2021).

In short, the lack of consideration for energy justice issues within the global framework of energy governance will likely just perpetuate historical disadvantages within communities (Symons and Friederich, 2022). This is a function of existing power structures within current governance structures. Beyond that, Symons and Friederich (2022) show that the political sovereignty of communities making independent decisions over energy project development will always result in outcomes that serve each group's self-interest and ignore the externality problems. Without intentional adjustments to governance that deal with these structural problems, the current paradigm will continue to create winners and losers and perpetuate the current disenfranchisement of some communities.

Good governance strategies for energy project development require support from the government, reliable capital and operational funding, diversification goals for the economy, and diverse coalitions (Wang and Lo, 2021; Cha, Wander, and Pastor, 2020). Finally, the creation of ownership stake opportunities at the onset of project development for disadvantaged communities is critical to ensuring that the tradeoffs between disenfranchised communities and the regional benefits of energy projects ameliorate losses. Greater rates of acceptance have been found to exist within communities with larger ownership stakes in energy projects (Hogan et al., 2022).

7.9 Sustainable Development

The desire to balance environmental protection and economic development in disadvantaged and frontline communities has led to the championing of a concept called "sustainable development." Summarized broadly, the idea is to balance the needs of current generations without harming the well-being of future generations. Within this movement, the needs of today's impoverished communities are heavily weighted under the theory that gains in wealth and income of today's generation beget gains in tomorrow's generation. In other words, the benefits of economic development compound over generations (Poppel, 2018).

In practical use, the concept of sustainability can be vague (Grossmann et al., 2022). One oft-missing area of focus is the tradeoff between environmental protection advocacy for disadvantaged communities and advocacy with these same communities for energy justice and sustainable development. The concept of embedded sustainable development outlines criteria for energy project development to be measured in terms of how energy justice efforts compare to the energy privilege of communities (Ciplet, 2021).

In 2015, the United Nations outlined a list of 17 Sustainable Development Goals that define the focus of sustainability as a practice (United Nations, 2015). Oriented toward 2030 outcomes, the 17 outcomes broadly fall into Barbier's (1987) canonical "three systems" approach to

process development: environmental, social, and economic. Broadly speaking, the 17 goals break down into the promotion of clean water and sanitation services alongside sustainable cities and sustainable economic growth with full employment as well as the sustainable development of natural resources. They also promote the end to food insecurity and poverty, greater levels of societal health and well-being, lifelong inclusive/equitable educational opportunities, and gender equality, as well as strong judicial and governmental institutions. Finally, the United Nations (2015) advocates for the proactive implementation of climate change policy that results in energy infrastructure resilience where communities have access to reliable and affordable clean energy.

Cherepovitsyn and Evseeva (2020) proffer several criteria to promote sustainable development within the context of LNG project development in the arctic—an area currently receiving a great deal of attention for energy development projects. The authors note the importance of sustainable development in the arctic as it is home to over 20 percent of the world's hydrocarbon resources. To promote sustainable outcomes, they propose seven criteria of sustainable development goals[r]:

- Project development must minimize environmental impacts at the construction and operation site
- Natural resource use should be efficient
- Local community support is paramount as is the effort to preserve indigenous culture and heritage
- Long-run regional economic gains that benefit and reflect stakeholder expectations should be prioritized
- Larger energy infrastructure development goals are achieved
- Innovations to industry technology are achieved
- Strengthening the regional LNG market relative to the global network is achieved

7.10 CONCLUSION

Historical disenfranchisement of communities has often resulted in the creation of winners and losers with respect to policy impacts. To the extent that policy has created the conditions under which disadvantaged communities arise, those policies have likely been rooted in a fundamental lack of inclusivity in the planning and implementation processes of project development. As the United States continues to embark on a transition away from a GHG-intensive economy, the chance to right those historical wrongs presents itself.

DOE deploys the Climate and Economic Justice Screening Tool to identify disadvantaged communities. To do so, the tool pulls in geographic information system data on the universe of communities whose boundaries are defined by the U.S. Census. These communities are identified as disadvantaged if that census tract meets the criteria for disadvantage in one of the

[r] Note that while the framework for measuring outcomes by Cherepovitsyn and Evseeva (2020) focuses on the arctic, this approach may be prudent for any LNG project development strategy. As such, the seven points have been modestly edited to apply more broadly.

categories describing burden or if that community resides within the boundary of a federally-recognize tribe.

The panoply of burdens fall within a framework of several categories. The threshold for being considered disadvantaged under the Climate Change category is that the census tract is at the 90th percentile for agriculture loss, building loss, population loss, or flood and wildfire risk. For Energy, the census tract is at the 90th percentile for energy costs. For Health, the census tract is at the 90th percentile for asthma, diabetes, heart disease, or low life expectancy. For Housing, the census tract is at the 90th percentile for green space deficits, indoor plumbing, or lead paint exposure as well as they have experienced historical disinvestment in housing. For Legacy Pollution, the census tract is at the 90th percentile of exposure to facilities that have dealt with hazardous waste, former defense sites, are proximal to a superfund site or a risk management facility. For Transportation, the census tract is at the 90th percentile for exposure to various environmental particulates, face barriers to transportation access, or barriers due to volume. For Water and Wastewater, the census tract is at the 90th percentile for exposure to storage tanks or releases underground, or the discharge of wastewater. For Workforce Development, the census tract is at the 90th percentile for isolation by their linguistic background, poverty, unemployment, or an overall lower median income.

Currently, the tool identifies roughly 27,251 communities at the census tract level. The deployment of tools like this during the energy transition is key, particularly during the early planning stages, in creating the approach for community outreach, and in the effort to structure governance strategies. Identifying where disadvantaged communities are provides the high-level understanding into where deficits in outreach and inclusion have likely exacerbated the pervasiveness of disadvantage. In doing so, concerted efforts to bring these voices into the development of large-scale energy infrastructure projects related to natural gas/LNG market opportunities is key.

The calls to advocate for energy justice during this transition have grown as the salience of climate change threats grows. Achieving a just transition is largely a functioning of process. The once-in-a-lifetime opportunity to restructure current processes around the core concepts of distributional, procedural, and recognition justice is significant. Re-framing the foundations upon which critical U.S. energy infrastructure is built by bringing diverse voices and stakeholders to the planning table will help to ensure that the best laid plans produce results that facilitate the growth for all, not just some.

To do so, there is a need to accept the existence of frictions innate to energy justice and energy poverty. Providing economic growth opportunities in GHG-intensive regional economies is as paramount as the need for ensuring reliable, affordable, and clean energy for those suffering from a historic lack of energy access. This may require adjusting the method of measuring the benefits and costs of large-scale U.S. energy infrastructure investments. The implementation of the Biden-Harris Administration’s Justice40 initiative speaks to this effort.

This chapter provides the framework for pursuing inclusivity goals in its discussion of energy justice and energy poverty. The energy transition is presented as a catalyst for pursuing change with the intended outcome being a just transition for all. In the end, the vehicle for applying

energy justice and energy poverty goals rests in the inclusive design of energy governance structures.

The literature base of energy justice and energy poverty within the space of natural gas and LNG market development is strong and growing. With intentionality, the authors of future research can help to ameliorate those historical disenfranchisements and provide a framework for the kind of shared prosperity that induces strong growth for all.

7.11 References

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From: Harker Steele, Amanda J.
Sent: Fri, 11 Aug 2023 19:25:45 +0000
To: Easley, Kevin; Curry, Thomas; Skone, Timothy; Sweeney, Amy
Cc: Robert Wallace; hartesingh@deloitte.com; Adder, Justin (NETL); Francisco De La Chesnaye
Subject: LNG Regulatory Analysis Support - Task 4 Env. Review Update
Attachments: 8_11_23.zip

Hi Tom, Amy, Tim, and Kevin,

*DRAFT*DELIBERATIVE*PRE-DECISIONAL*

Good afternoon! The team has been hard at work updating Ch. 1 - 6 of the report and I am happy to report we are ready to submit today instead of on Monday.

The attached .zip folder contains 1) A revised clean version of the report with a few minor comments for your consideration, 2) a comment response log which contains comments from the reviewed version of the report sent to NETL on 7/28, some comments from the meetings that occurred 7/28-8/2 and our responses, and 3) an image permission tracking log.

We would ask that ask done previously any additional comments from FECM be delivered to NETL all at once, in a consolidated format including any additional references you'd like us to add. This helps us in managing our timeline to completion.

We will be in touch early next week with a plan and schedule for Ch. 7. Since our typical monthly check-in meeting will be dedicated to the LCA team next week I'll be in touch regarding a meeting time for the schedule.

I hope you all have a nice weekend! We look forward to getting your feedback. Thanks!

Sincerely,
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Response to Comments for POTENTIAL ENVIRONMENTAL IMPACTS ASSOCIATED WITH UNCONVENTIONAL NATURAL GAS

Comment Number	Reviewer	Comment	Resolution
1	Over-arching Comments	• Global: Chapters 2-7 should include a brief summary of the findings or key takeaways; this could be at the opening or the end of the chapter but should be consistent in each chapter. • Chapter 1: The regulatory review should be shortened and kept at a high level. • Remaining chapters: o Remove regulatory sections. o Include R&D in each section but create a parallel section. • Incorporate new literature sources received from/shared by Kevin & Tim from last 2 weeks.	• In this iteration we have not included the brief summary of the findings and key takeaways for each chapter 2-7. We discussed this internally and decided that these additions would likely be best to add in at the end once we have an agreement on where content should be located. Under this approach, those paragraphs will be able to capture more fully the contents of each chapter. We have drafts from previous versions which should allow us to do this quickly. • Done. Regulations are now discussed in Ch. 1. R&D included in each section where applicable. • The majority of the references shared via email have been incorporated into this draft. Some were not a good fit so they were left out. Please advise if you would like to see a detailed list of which ones were included vs. which ones were not.
2	Tom C.	Global comment: is the EJ chapter consistent with the frame of "environmental impacts"? Should the title and introduction be "environmental and community impacts"? I'd like feedback from Kelli, Natenna, and Odysseus on this.	TBD. See comment below. Also added note in newest draft so this comment is not lost.
3	Tim S.	Guidance to NETL: We are interested in your thoughts if the title is still accurate or should be changed to reflect that the addition of EJ and that the natural gas sections discuss both unconventional and conventional gas production.	TBD. We should know more once we have a complete draft of Ch.7 that incorporates the suggested edits and additional sources of information.
4	Tim S.	Header text needs to fit on one line.	Done
5	Tom C.	@Lavoie, Brian D. should we specify that this is for authorizations to non-FTA countries or is the use of this document broader to include all authorizations?	Change accepted. See footnote a.

Response to Comments for ***POTENTIAL ENVIRONMENTAL IMPACTS ASSOCIATED WITH UNCONVENTIONAL NATURAL GAS***

Comment Number	Reviewer	Comment	Resolution
6	Brian L.	It's correct that this would only be used for non-FTA applications. (FTA applications are not subject to DOE NEPA review.) I'd suggest maybe just a footnote on this (see my suggestion), so as not to distract the reader at this early point. (Amy/Jen - please jump in if you have a different view.)	
7	Tim S.	Guidance to NETL: Add Brian's suggested footnote.	
8	Brian L.	Suggest consider, "may" and similar language that reflects uncertainties about impacts.	Adjusted
9	Brian L.	@Easley, Kevin do you suggest in-text treatment of this point vs. the footnote? I think it should be one or the other.	Non- NETL
10	Kevin E.	I don't have a preference. But my sense is not everyone reading this Addendum will know what exactly goes into / governs a DOE 'public interest determination.' I defer to you and @Sweeney, Amy, @Lavoie, Brian D.	
11	Brian L.	"such activities" near the end of this passage, at least textually as written, refers to "both conventional and unconventional natural gas markets" earlier in the passage. Suggest clarifying to focus on unconventional, which is the topic of this report.	Done
12	Brian L.	Can something be said like that the authors believe this survey is representative and no significant areas have been excluded from this review?	Done
13	Tim S.	The HHV of natural gas used in the LCA work is 1,031 Btu/scf (54.1 MJ/kg) [60 deg F, 1 atm]. You need to specify HHV or LHV and at what standard conditions you are reporting. My understanding is that the oil & gas industry uses 60F / 1atm as the definition of "standard" conditions, while the industrial gas industry prefers 70F / 1atm.	Footnote added for clarity.
14	Tim S.	NETL: we added this text for clarity, is it still appropriate to reference BP, 2017? Please confirm.	BP reference still appropriate. Change accepted.
15	Amanda H.	Does the new text impact the accuracy of the reference to BP 2017 or do we need to add an additional reference or move the BP reference.?	
16	Brian L.	Should increasing exports be mentioned here, for completeness?	Adjusted
17	Tom C.	I assume NETL has requested permission for all the figures, what is the timeline for getting these permissions in place?	Done, there are now only two pending permissions. We're unable to give a timeline on behalf of the copyright holders. If permission hasn't been received by the time this report is finalized, the third-party graphics will be removed.
18	Tim S.	NETL: please create a graphic permission tracker with the received permissions contained/linked to archive with the project files. Thank you.	
19	Tom C.	Are there years that it did not increase? I'd rather not use "mostly" unless necessary. Would prefer to say, "With the except of X years, production has increase year over year since 2005…"	I have removed the words "mostly" and "year-over-year" such that the focus is on the general trend between 2005 and 2023, and not any specific year. Adjusted following Tom's recommendation.
20	Amanda H.	State-Level production data is not yet available for 2022 from the EIA. Do you prefer we remove this figure?	Added footnote for clarity. Also, adjusted the paragraph above to

Response to Comments for POTENTIAL ENVIRONMENTAL IMPACTS ASSOCIATED WITH UNCONVENTIONAL NATURAL GAS

Comment Number	Reviewer	Comment	Resolution
21	Tim S.	NETL: Keep figure BUT add to paragraph above the 2021 US dry gas production total put it in context to the 2022 value and support the 2021 figure. It is okay to state that 2022 state level data was not available at the time of report production in a footnote if you would like.	reflect production in 2021 and within the context of production in 2022.
22	Amanda H.	Add paragraph on 2021 dry production national volume to set up explanation.	
23	Tim S.	NETL: we removed all discussion of projections from this document that followed Exhibit 1-4. Projections will be covered by the GCAM/NEMS work. Thanks.	Change accepted.
24	Amanda H.	Let today (7/31) conversation lead the way on approach to addressing revisions. Plan should be to consolidate. For each chapter see if it makes sense to move content in the chapter to this section of the report.	Done
25	Amanda H.	Maybe add a Venn Diagram of interaction between federal and state if we can. It may or may not be possible.	Continuing to evaluate if this is possible. No change made in this revision.
26	Tom C.	BLM proposed rules to regulate methane releases in federal lands in 2021. Interior Department Takes Action to Reduce Methane Releases on Public and Tribal Lands | Bureau of Land Management (blm.gov)	Added. Rule was from 2022.
27	Tim S.	NETL: please add the 2021 rule to the discussion.	
28	Kevin	Please add ESA to the Acronym List.	Added
29	Tom C.	I recommend revising this section to generally discuss EPA's role establishing regulations for air, GHG emissions, and water. The specifics on each could then be moved to the appropriate sections in the chapters.	Added a sentence that provides this framing to begin this paragraph.
30	Tim S.	NETL: Note global guidance is to consolidate at a high level the regulatory discussion within Chapter 1. Please disregard the following part of the comment form Tom above " The specifics on each could then be moved to the appropriate sections in the chapters."	
31	Amanda H.	First part of Tom's comment should still be addressed.	
32	Kevin E.	Please add CAA to the Acronyms List.	Added
33	Brian L.	Please check timing/dates -- 2020 engagement was reported on in 2019?	Corrected.
34	Brian L.	Citation?	Added in-text, and in the reference section.
35	Kevin E.	Please add CWA to the Acronym List.	Added
36	Brian L.	Is there anything that can be said at the end of the paragraph on current status? Or timeline expected for final rule?	Added sentence at the end noting that evaluation is still in progress.
37	Amanda H.	If it is significant, it may be worth noting what is in process. But we don’t want to mention what will happen. Take an agnostic approach and mention it is in progress.	
38	Kevin E.	Please add NEPA to the Acronym List.	Added

Response to Comments for POTENTIAL ENVIRONMENTAL IMPACTS ASSOCIATED WITH UNCONVENTIONAL NATURAL GAS

Comment Number	Reviewer	Comment	Resolution
39	Kevin E.	Please add both DOT and MARAD to the Acronym List.	DOT added. MARAD was not used again so this was deleted.
40	Kevin E.	Please add USCG to the Acronym List.	USGC is not used again, so acronym was deleted.
41	Tim S.	We issued an RFI, but do we have funded work on these paths today?	
42	Tim S.	NETL: we softened this language as we have not funded CCS or electric motor conversion to support the verb "deployment".	Change accepted.
43	Amanda H.	No answer on top question required. Double check changes don't impact author's point/message.	
44	Tim S.	This sentence is broader than Shale Gas Research and better aligns to the Methane Mitigation paragraph above for the LCA work. Produced water is in a different program line as well.	Change accepted.
45	Kevin E.	Please add NGOs to the Acronym List.	Added
46	Tim S.	This sentence is broader than Shale Gas Research and better aligns to the Methane Mitigation paragraph above for the LCA work. Produced water is in a different program line as well.	We moved the sentence. Please confirm you are okay with the move
47	Kevin E.	Please add RFI to the Acronym List.	Added
48	Kevin E.	Please add R&D to the Acronym List.	Added
49	Kevin E.	Please add OSHA to the Acronyms List.	Added
50	Kevin E.	NETL Team - Changed 'If' to 'When' since the Addendum has already cited wastewater injection is one driver of induced seismicity.	Done
51	Kevin E.	NETL Team - it's unclear who the 'Applicants' are, what they are applying to, etc. Please provide additional details. Are we referring to operators in Texas applying for permits of one type or another RE: drilling, disposal, etc.? Please clarify.	Adjusted language to remove the term applicants but we need to review in more detail/ Information is available here and just lists "applicants" https://www.americangeosciences.org/sites/default/files/webinar/assets/AGI_InducedEQ_Webinar_Apr2017_Young.pdf
52	Brian L.	Is any update available?	Need to also explore this further. Please provide more context – are you asking if an update to the list of requirements is available or the reference?
53	Kevin E.	NETL Team - the 'shorthand' in these bullets is confusing, poorly written, and as such I'm uncertain if my proposed text revisions are correctly adjusting the text to make it more understandable. Please feel free to expand upon / revise this section as needed.	Removed list.
54	Kevin E.	NETL Team - please flesh this out as this is very technical terminology many prospective users / readers of the Addendum may not readily recognize / understand.	Please advise further.

Response to Comments for POTENTIAL ENVIRONMENTAL IMPACTS ASSOCIATED WITH UNCONVENTIONAL NATURAL GAS

Comment Number	Reviewer	Comment	Resolution
55	Amanda H.	Refrain from fleshing out now so we can stay high level.	
56	Kevin E.	NETL Team - please add some text to describe why stages may need to be skipped due to seismic events indicating "a lineament or fault structure near a lateral of the operation."	Removed
57	Kevin E.	NETL Team - what is meant by / the consequences of this phrase: "full effect still unsure' when switching to smaller sieve sizes for proppant.	Removed
58	Tim S.	This diagram is missing a few steps. Gathering and Boosting Piped Transmission and Storage between "Processing" and "Liquefaction". Is there a more accurate diagram that better aligns with the NETL or EPA GHGRP or GHGI categories and emission sources?	Custom graphic made.
59	Amanda H.	Create custom NETL graphic.	
60	Brian L.	GHG emissions? Not only CH4, correct? In this section generally, sometimes reference is made to CH4 monitoring/detection - suggest some explanation of when only CH4 is measured and when all GHGs are considered.	Corrected.
61	Amanda H.	Make distinction between just CH4 and GHG more clear.	
62	Tim S.	This needs to be balanced with the understanding that in the 12 year the radiative forcing is changing. I cannot find a reference to support the 120 times? Is this in watts/meter perspective? Recommend we stay with IPCC 100 yr and 20-year perspective of difference in radiative forcing. The temporal period of how long the pollutant stays in the atmosphere is critical to understanding its relative radiative forcing when compared to other GHGs, CO2. Remove or provide the complete story.	Deleted
63	Amanda H.	Take this out.	
64	Tim S.	CO2 also declines over time, not constant. The temporal period is just longer. You confirm my point in the previous sentence. This paragraph is misleading because it is not telling the complete story. A radiative forcing decay graphic showing a single pulse of emissions at time = zero is needed to tell the complete story. Alternatively, this paragraph. I would keep the first two sentences and use them as the start of the next paragraph on GWP.	Sentence has been removed.
65	Amanda H.	Define if not yet done so in text.	Done
66	Tim S.	Need to mention the LNG work at the beginning and discuss that the LNG report builds upon the NELT upstream natural gas report by adding liquefaction, ocean transport, regasification, distribution and end use of the gas in a large-scale power plant. This will help create synergies to the Exhibit 2-1 description of the natural gas and LNG system boundary. For Exhibit 2-1, you may want to create your own graphic.	Text added. For Exhibit 2-1, custom graphic made.
67	Tim S.	Need higher quality image and to cite image source.	Higher-resolution image added.
68	Amanda H.	Could give its own page to sharpen	
69	Tim S.	Add citation	Added (in-text and in references section).

Response to Comments for POTENTIAL ENVIRONMENTAL IMPACTS ASSOCIATED WITH UNCONVENTIONAL NATURAL GAS

Comment Number	Reviewer	Comment	Resolution
70	Tim S.	Add GHGRP (this is the primary data source, not GHGI)	Correction made.
71	Brian L.	Suggest citing somehow that Exhibits 2-3 and 2-4 are from the referenced NETL 2019 report.	In-text citations added.
72	Brian L.	Figure would benefit from a legend or explanation of the different elements.	Explanation in paragraph before.
73	Tim S.	Cite source.	Citation added
74	Tim S.	State what year the data represents in the caption and what scope? US average for transmission and distribution combined?	Clarification added. Covers the Production, G&B, Processing, Transmission, and Distribution.
75	Tim S.	Need higher resolution image.	Higher resolution Exhibit added.
76	Brian L.	slips through the compressor uncombusted into the exhaust stream"?	Yes – Response by Tim to Brian
77	Tim S.	Exhibit 2-5 and 2-6 units, while the same, are described differently. Exhibit 2-5 is the general standard with the exception of carbon dioxide equivalents are ported as CO2e (subscripted 2) and not as CO2-eq in Exhibit 2.5.	Added units within Exhibit title to avoid this confusion.
78	Tim S.	The data does not support this statement. Liquids Unloading is 0.5 g CO2e (Exhibit 2-5) per the life cycle total of 19.9 with a mean uncertainty range of 13.1 to 28.7. The variance in liquids unloading is well within the mean uncertainty range and therefore not a sensitive parameter. Exhibit 6-8 in the NETL 2019 report provides a ranking of GHG emissions uncertainty (not model sensitivity) but does indicate which sources contribute have an influence on the accuracy of the results. Results are sensitive to: • EUR • Regional natural gas composition differences (dry versus sour gas). • Compression energy requirements and type. • Pneumatic device type, frequency, and number of devices per operation. • Episodic events that result in higher (than normal operations) methane emissions over a short time frame (not a consistent emission source) originating from maintenance and inspection activities or non-standard operator practices. The above bullet provides a more generic way of describing episodic emissions. My concern was calling out specifically liquids unloading and workovers.	Adjusted language.
79	Amanda H.	Adjust sentence to reflect list provided above.	
80	Brian L.	Is this a separate NETL 2019 report? Or the same one as above? If the same, suggest citing it in full on first mention.	Since there are two NETL 2019 cited, a letter distinction (i.e., 2019a or 2019b) was added.
81	Tim S.	Yes, a different report.	
82	Brian L.	Suggest somewhere a comment be made that the supply chain study presented above is "cradle to gate," and excludes end-use, while the LNG study is more truly "cradle to grave," and does include	Please advise if still needed. Marked as resolved currently.

Comment Number	Reviewer	Comment	Resolution
		end-use (power generation), meaning extra care should be taken by readers in comparing results and figures.	
83	Tim S.	This report does not discuss global natural gas supply sources? I think you mean US.	Corrected.
84	Brian L.	How does this compare with other analyses we rely on? Do we rely on national averages elsewhere	Please advise if still needed. Marked as resolved currently.
85	Brian L.	Comment applicable to other sections as well -- is text being updated with more recent studies? (apologies if updating is ongoing in some sections and I'm not aware of it) Most or all of these studies (aside from NETL's) are >10 years old.	Yes, made updates.
86	Brian L.	Comment applicable to other sections as well -- is text being updated with more recent studies? (apologies if updating is ongoing in some sections and I'm not aware of it) Most or all of these studies (aside from NETL's) are >10 years old.	See above
87	Amanda H.	Hartej - I'm wondering if the earlier EPA reference should go here?	I moved the earlier EPA reference to Section 2.1 where we introduce the concept of bottoms up and top-down, I think it is most relevant there, but I have added some text to this sentence as well.
88	Tim S.	This sentence seems to conflict with the 2.5 times difference between Rutherford and EPA? I am not sure I am interpreting your point correctly. Also, what year does the data represent in the EPA GHGI to Rutherford comparison?	Adjusted.
89	Amanda H.	Revise sentence.	
90	Tim S.	If this is 2015 data, is this still a current perspective of the industry performance? Does the latest EPA GHGI still result in this conclusion?	Instead of making a statement, I have input data from a very recent EPA report below as a new Exhibit 2-9. In Exhibit 2-8, the reader can see that EPA GHGI had natural gas production segment emissions at about 3.6 Tg (or ~3,600 kt of CH4) in 2015. One can observe from Exhibit 2-9 that 2021 natural gas production segment emissions are 3.36 Tg CH4 (or 3,360 kt CH4). There is no more contemporary study that exists (beyond Alvarez or Rutherford) that dissects EPA GHGI data post 2015.
91	Amanda H.	Is the comparison still accurate? If we cannot find a more contemporary comparison, should we make a statement on them? Suggest framing the discussion that updates have been made by EPA, etc. Adjust framing. Softening context.	
92	Brian L.	Comment applicable to other sections as well -- is text being updated with more recent studies? (apologies if updating is ongoing in some sections and I'm not aware of it) Most or all of these studies (aside from NETL's) are >10 years old.	See comment above.

Response to Comments for POTENTIAL ENVIRONMENTAL IMPACTS ASSOCIATED WITH UNCONVENTIONAL NATURAL GAS

Comment Number	Reviewer	Comment	Resolution
93	Brian L.	Does this mean +/- 150%? Or something else?	Yes. Corrected.
94	Brian L.	Which study? Roman-White or NETL?	Corrected.
95	Tim S.	What is the source? If this the ONE Future report, it was limited to the ONE Futures value chain and not the US average.	In-text citation added above. This is not the ONE Future report, it is from the following report: NETL. (2020). Opportunities for Natural Gas Supply Chain Efficiency. NETL. 56(22). 2020/2618
96	Brian L.	This paragraph seems a little bit tacked-on. Consider adding context or possibly deleting.	Deleted
97	Brian L.	Consider adding an introductory sentence or paragraph with an overall statement about types of mitigation measures discussed in this section.	Introductory paragraph added to Section 2.4, conclusion/key-takeaways paragraph added at the end of Section 2.3.
98	Tim S.	Agree to delete this paragraph and replace with a concluding paragraph for Section 2.3. What is the takeaway message from all of these reports and data?	
99	Brian L.	Note to reviewers - I think Tim's response here goes with the comment above -- regarding the current last para of section 2.3	
100	Brian L.	Which regulations? Suggest explain why they are being mentioned here.	Moved regulations section to Ch. 1. Please advise if still needing to address.
101	Brian L.	It may be confusing that this is the name of "equipment." Suggest a little explanation if possible.	Section removed.
102	Tim S.	RECs are required by law now this not a current issue for the industry. The point that REC implementation has shifted the emissions from methane to CO2 has occurred and did reduce GHG intensity form a global warming perspective.	Made it clear that RECs are mandatory.
103	Amanda H.	Make clear its mandatory.	
104	Kevin E.	NETL Team - with this proposed text correction, is the statement now accurate?	Correct. Also added a footnote to explain this concept.
105	Tim S.	What is the source? If this the ONE Future report, it was limited to the ONE Futures value chain and not the US average.	In-text citation added above. This is not the ONE Future report, it is from the following report: NETL. (2020). Opportunities for Natural Gas Supply Chain Efficiency. NETL. 56(22). 2020/2618
106	Brian L.	Suggest explain this term	This refers to heat integration, a common (but fairly technical) design optimization practice in chemical engineering processes. Added a footnote to explain.
107	Brian L.	Can you add a parenthetical example?	Added a footnote that helps explain this concept.

Response to Comments for POTENTIAL ENVIRONMENTAL IMPACTS ASSOCIATED WITH UNCONVENTIONAL NATURAL GAS

Comment Number	Reviewer	Comment	Resolution
108	Tim S.	This reads like an NETL statement. When quoting another others recommendations or key conclusions, it would help if the text read Pspeisel et al, 2019 recommends…. Universal comment to ensure clarity on who's recommendations or findings are being discussed.	Corrected.
109	Brian L.	Do you mean aggregate emissions in the world? Or GHG emissions?	Clarification added.
110	Kevin E.	Please add CCS to the Acronym List.	Added.
111	Brian L.	Unclear what this means	Clarified.
112	Brian L.	A term like "natural gas-fired power generation" might be more clear.	Marked as resolved previously.
113	Brian L.	"exploration and production"? Are we including exploration?	Correction made.
114	Kevin E.	Please add Nox to the Acronym list.	Done.
115	Brian L.	Suggest explain in parens or a footnote what compounds this represents	Footnote added.
116	Tom C.	Is the a reference for this finding? I would have thought safety at offshore platforms also would have driven lower emission rates. If we don't have a reference or more supporting documentation, I think the sentence could be deleted without impacting the narrative.	Deleted.
117	Amanda H.	Offshore lower profile is due to greater safety measurers needed to manage greater risks.	
118	Brian L.	Suggest explain wet gas vs. dry gas	Included as footnote.
119	Suzanne W.	I think that would be helpful.	
120	Tom C.	I'm not following the discussion in this paragraph. Air toxics, or hazardous air pollutants (HAPs), are regulated by EPA under the NESHAP (https://www.epa.gov/stationary-sources-air-pollution/oil-and-natural-gas-production-facilities-national-emission). Would the organic toxic compounds discussed here be regulated under the NESHAP?	Removed paragraph.
121	Kevin E.	Agreed. I'm slightly confused as well. After NETL provides clarification, please add NAAQS to the acronym list.	
122	Amanda H.	Add more context to sharpen discussion.	
123	Brian L.	"incomplete"?	Please provide more context for comment?
124	Tom C.	Does Exhibit 3-2 use EPA's Integrated Risk Information System? I don't understand the connection between the Integrated Risk Information System and the other statements in this paragraph or the Exhibit.	Deleted text on Integrated Risk Information System as it added unnecessary confusion.
125	Tom C.	Recommend deleting this figure or moving to the GHG chapter.	Eliminated figure on flaring.

Response to Comments for POTENTIAL ENVIRONMENTAL IMPACTS ASSOCIATED WITH UNCONVENTIONAL NATURAL GAS

Comment Number	Reviewer	Comment	Resolution
126	Kevin E.	If we retain the figure and move it to the GHG chapter, I still have the following concern: given the enormous flaring outlier data from the Permian Basin reflects, if there is positive movement there (in Texas and / or New Mexico, etc.) in terms of new / proposed flaring regulations, sustainable practices voluntarily advanced by key / several operators, etc., I suggest we add that additional context to the text narrative. The flaring problems in the Permian profiled previously by EDF and others influenced European buyers (e.g., French utility Engie back in 2020) who became increasingly concerned with and began to oppose the importation of 'dirty gas' from that massive play.	
127	Tim S.	NETL: Move to GHG section or delete.	
128	Amanda H.	Open to making the point but chart should reflect. Reflect flaring is issue in some basins but not nationwide. Don't want to talk about outliers.	
129	Brian L.	Would it be desireable to provide specific comment on midstream methane emissions, since methane has been cited as an ozone precursor in addition to being a GHG? Possibly it could be a reference to the chapter on GHGs.	Added this detail as an intro paragraph to this section.
130	Tom C.	Please delete this section, end use emissions are out of scope. Some of the information about upstream air emission source might be appropriate to move above.	Done.
131	Amanda H.	End-Use is not within scope so we don't need a discussion. Could remove unless there is something recyclable. If so add to another section.	
132	Amanda H.	HH - Comments from Heshem. May need a call between HH and NETL to include more R&D.	Had call. Incorporated feedback as requested.
133	Brian L.	Volumes of water use?	changed
134	Amanda H.	Comment for FE HQ - While this source is older than 2014 it helps to build the context for this section. Please advise if another more recent source is available and we will update accordingly.	Incorporated sources from HH as we could.
135	Hichem H.	Hello Amanda, Thank you for your comment. Please see the references below. Also, please feel free to reference our FOA 2796 (especially in the background secton) for updates on the WM program's vision and technical focus areas: https://www.gwpc.org/wp-content/uploads/2023/05/State-Regulations-Report-2021-Published-May-2023-FINAL.pdf https://www.gwpc.org/wp-content/uploads/2023/06/2023-Produced-Water-Report-Update-FINAL-REPORT.pdf https://www.gwpc.org/wp-content/uploads/2021/09/2021_Produced_Water_Volumes.pdf https://www.energy.gov/fecm/funding-notice-water-research-and-development-oil-and-gas-produced-water-and-coal-combustion	
136	Kevin E.	HH: Note about induced seismicity, which has become one of the main reasons for regulatory "Sticks" that are driving technological innovation.	Removed.
137	Amanda H.	Induced seismicity is in response to injection rather than depletion. Double check with HH.	

Response to Comments for POTENTIAL ENVIRONMENTAL IMPACTS ASSOCIATED WITH UNCONVENTIONAL NATURAL GAS

Comment Number	Reviewer	Comment	Resolution
138	Amanda H.	Don't include here	
139	Rachel H.	It was the State of PA that asked companies to stop doing this, so I would rephrase. According to PSU, "PaDEP asked gas drilling operators to voluntarily stop using these plants for Marcellus wastewater disposal by May 2011 because of mounting water quality concerns downstream of municipal wastewater discharge points." https://extension.psu.edu/waters-journey-through-the-shale-gas-processes	Will rephrase and thank you for the reference.
140	Brian L.	In places like this where literature cited is of this vintage, it might be helpful to add something saying that these are the most recent studies available. [See global comment at beginning of document.]	Understood I did add a 2016 reference too.
141	Brian L.	Suggest update phrasing to more precise years as this reads as 2013-2023 to a current reader.	Will do.
142	Kevin E.	Is the 2015 induced seismicity information presented here sufficiently 'recent' for the purposes of this Addendum? Is more recent data available from USGS as the graph at the top of the page and supporting text narrative refers to a 2022 data source.	I will double check. I did not find any literature that shows seismicity specifically related to this region more recent than this article.
143	Kevin E.	NETL Team - 'moment' (as written) or events or some other term? If 'moment,' it's unclear what message / finding the sentence is trying to convey. Also, 'of' Oklahoma' (as written) or 'in' Oklahoma.	Will check for consistency I added a footnote, since seismic moment is a physical term that is an equation.
144	Kevin E.	NETL Team - this sentence appears to be incomplete. If it is meant to amplify the preceding sentence, I suggest it be reworded as it's confusing / unclear as written.	It is incomplete. I believe there should have been a comma after the last word of the previous sentence. fixed
145	Kevin E.	NETL Team - did you mean to type the graphy on the right in Exhibit 5-3 as it's the one that has a 'time series' (2010 - 2019) along the horizontal axis.	Yes, corrected.
146	Amanda H.	Go back to writing on induced seismicity from the 2014 report. In section 1 highlight what of significance has changed if anything? In other words, what details below are critical to enhancing the public's knowledge on the regulatory actions taken to address induced seismicity. Don't need 5 pages on this but a paragraph on others. Section 1 regulations should be balanced.	With respect to R&D, there was really nothing in the previous report. If you are asking this question to the entire section, this updated report has far more description of what happened in more specifics than the previous report.
147	Brian L.	Is any update available?	Adjusted. Continuous process.
148	Kevin E.	NETL Team - suggest removing 'plants' here as we're focused on the activity itself; if you want to footnote a point RE: land required for all of the processing plants involved in unconventional production here in the U.S., if necessary, that would be fine.	ok
149	Kevin E.	NETL Team - 'the use through' was somewhat clunky so I switched up the text.	ok
150	Brian L.	Suggest a few words explaining how, or possibly delete this sentence.	I will look to expand the text from the source. If I cannot find specific examples, I will delete the sentence. Expanded from the source.

Response to Comments for POTENTIAL ENVIRONMENTAL IMPACTS ASSOCIATED WITH UNCONVENTIONAL NATURAL GAS

Comment Number	Reviewer	Comment	Resolution
151	Kevin E.	Please add OECD to the Acronyms List.	Will do. Added
152	Brian L.	This section should be alongside material in the first para of this section that addresses some human health effects.	Will move it. Thank you! moved
153	Brian L.	Is "pollution" the right term? Air pollution from traffic is addressed above, so perhaps just "traffic"?	ok
154	Amanda H.	Please advise if this is incorrect. We made every attempt to find information on current and ongoing R&D.	I performed a broader search and still did not find any R&D by DOE here.
155	Tim S.	If you are not sure it is accurate, we should not say it.	

POTENTIAL ENVIRONMENTAL IMPACTS ASSOCIATED WITH UNCONVENTIONAL NATURAL GAS

Commented [HSAJ1]: Note for FECM - We are still contemplating an appropriate title. We anticipate this will be a collective decision following the review of the new Ch. 7.

August 11, 2023

DOE/NETL-2023/4388

DRAFT DELIBERATIVE PRE-DECISIONAL

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Disclaimer

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The authors wish to acknowledge the excellent guidance, contributions, and cooperation of the NETL staff, particularly:

Commented [HSAJ2]: Note for FECM - To be completed at the end.

Suggested Citation:
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TABLE OF CONTENTS

LIST OF EXHIBITS

ACRONYMS AND ABBREVIATIONS

AEO	Annual Energy Outlook
API	American Petroleum Institute
AR5	IPCC Fifth Assessment Report
B	Billion
Bcf	Billion cubic feet
BLM	Bureau of Land Management
BTEX	Benzene, toluene, ethylbenzene, xylenes
Btu	British thermal unit
CAA	Clean Air Act
CBM	Coalbed methane
CH_4	Methane
CMSC	Citizens Marcellus Shale Coalition
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_2e, CO_2-eq	Carbon dioxide equivalent
COGCC	Colorado Oil and Gas Conservation Commission
CRS	Congressional Research Service
CCS	Carbon capture and storage
CWA	Clean Water Act
d	Day
DOE	Department of Energy
DOI	Department of the Interior
DOT	Department of Transportation
EIA	Energy Information Administration
EDP	Exploration, development, and production
EPA	Environmental Protection Agency
ESA	Endangered Species Act
FECM	Office of Fossil Energy and Carbon Management
FERC	Federal Energy Regulatory Commission
FP	Flowback and produced (water)
ft, FT	Foot
g	Gram
G&B	Gathering and boosting
gal	Gallon
GHG	Greenhouse gas
GHGI	Greenhouse Gas Inventory
GHGRP	Greenhouse Gas Reporting Program
GWP	Global warming potential
GWPC	Groundwater Protection Council
H_2S	Hydrogen sulfide
HAP	Hazardous air pollutant
HPh	Horsepower-hour
IPCC	Intergovernmental Panel on Climate Change
kg	Kilogram
kJ	Kilojoule
km	Kilometer
km^2	Square kilometers
kWh	Kilowatt hour
LCA	Life cycle analysis
LNG	Liquefied natural gas
m^2	Square meter
m^3	Cubic meter
Mcf, MCF	Thousand cubic feet
min	Minute
MIT	Massachusetts Institute of Technology
mg	Milligram
MJ	Megajoule
MM	Million
MWh	Megawatt hour
NOx	Nitrous oxides
N_2O	Nitrous oxide
NEIC	National Earthquake Information Center
NEPA	National Environmental Policy Act
NETL	National Energy Technology Laboratory
NGL	Natural gas liquid
NGO	Non-governmental organization
NOAA	National Oceanic and Atmospheric Administration
NORM	Naturally occurring radioactive material

NOx	Nitrogen oxides
NPS	National Park Service
NSPS	New Source Performance Standards
NYSDEC	New York State Department of Environmental Conservation
O_2	Oxygen
OAC	Ohio Administrative Code
OECD	Organisation for Economic Co-operation and Development
OSHA	Occupational Safety and Health Administration
ONE Future	Our Nation's Energy Future
ORC	Ohio Revised Code
OSF	Oral slope factor
PA	Pennsylvania
PADCNR	Pennsylvania Department of Conservation & Natural Resources
PADEP	Pennsylvania Department of Environmental Protection
PM	Particulate matter
PRV	Pressure release valve
R&D	Research and development
REC	Reduced emission completion
RFF	Resources for the Future
RFI	Request for Information
RfV	Reference value
RRC	Railroad Commission of Texas
scf	Standard cubic foot
SDWA	Safe Drinking Water Act
SF_6	Sulfur hexafluoride
SO_2	Sulfur dioxide
T	Trillion
T-D, T&D	Transmission and distribution
T&S	Transport and storage
Tcf	Trillion cubic feet
tCO_2	Tonnes carbon dioxide
TDS	Total dissolved solids
TexNet	Texas' Center for Integrated Seismicity Research
tNG	Tonnes natural gas
Tg	Teragram
tonne	Metric ton
U.S.	United States
UIC	Underground Injection Control
USFS	U.S. Forest Service
USGS	U.S. Geological Survey
VOC	Volatile organic compound
WV	West Virginia
yr	Year

1 Introduction

The United States (U.S.) Department of Energy's (DOE) Natural Gas Regulatory Program is responsible for reviewing applications to import and/or export natural gas from and/or to foreign countries. An important dimension in considering whether to grant such authorizations is how the additional natural gas production and transport activities needed to support proposed actions may impact the environment.[a] Accordingly, potential impacts are factors affecting public interest.

Although fundamental uncertainties exist regarding the exact amount and location of natural gas production or transportation that would occur in response to additional authorizations being granted, it is important that DOE acknowledge and provide the public and decision-makers with access to updated information regarding the potential environmental consequences associated with such activities. Accordingly, DOE has prepared this update to the 2014 Addendum to Environmental Review Documents Concerning Exports of Natural Gas from the United States (hereafter the 2014 Addendum) (DOE, 2014).

It is not possible to estimate with certainty where, when, or by what method any additional natural gas would be produced, transported, or exported in response to the granting of authorizations to import and/or export natural gas. Therefore, DOE cannot meaningfully quantitatively analyze the specific environmental impacts associated with such activities. Therefore, as with the 2014 Addendum, this report provides only a review of peer-reviewed, scientific literature related to the potential environmental consequences of expanding natural gas production and related activities domestically.

As unconventional natural gas production has represented an ever-growing share of total U.S. natural gas production, the environmental impacts reviewed in this report relate primarily to those associated with unconventional production activities. The publications referenced build on a strong body of existing literature that traces the evolution of unconventional natural gas production techniques from their conceptual stages in the 1970s to the technology advancements that contributed to the shale gas boom of the early 2000s, as well as further development of additional unconventional resources, including tight gas sands and coalbed methane (CBM) resources to the export of liquefied natural gas (LNG).

This report attempts to summarize the published descriptions of the potential environmental impacts of natural gas operations within the lower 48 states as detailed by government, industry, academia, scientific, non-governmental, and citizen organizations. The sources cited are all publicly available documents. While this report by no means represents an exhaustive list of the sources that discuss environmental consequences of upstream natural gas activities,

[a] DOE is responsible for considering the environmental impact of its decisions on applications to export natural gas, including liquefied natural gas, to countries with which the United States has not entered into a free trade agreement requiring national treatment for trade in natural gas. (Applications for trade with free trade agreement countries are deemed to be in the public interest by statute.) DOE conducts environmental reviews under the National Environmental Policy Act and as part of its public interest review under the Natural Gas Act.

the sources cited are believed to be representative, and no significant areas have been excluded from the report.

Multiple publications on similar topics are compared based only on their technical and methodological distinctions. Over the past decade, the focus of environmental issues has evolved with some interest in the public literature varying over time. Key research in some areas remains the same with minor to no new additions to the basis of scientific knowledge, in this situation some historical references have been maintained. No opinion on or endorsement of these works is intended or implied.

This report is divided into chapters, each of which contains a separate section of references so that each type of environmental impact can be explored further. The types of environmental impacts that are documented in this review include the following:

- Greenhouse gas (GHG) emissions and climate change (Chapter 2)
- Air quality (Chapter 3)
- Water use and quality (Chapter 4)
- Induced seismicity (Chapter 5)
- Land use and development (Chapter 6)
- Environmental and social justice (Chapter 7)

Commented [HSAJ3]: Note for FECM - Ch. 7 has currently been stripped from this document and is in the process of being edited. It will be added back in at a future date.

In addition to containing information on potential environmental impacts, this report provides some background information on domestic natural gas production and federal and state regulatory processes related to managing impacts.

1.1 Natural Gas Basics

Natural gas is an odorless, gaseous mixture of hydrocarbons, largely made up of methane (CH_4) but also containing small amounts of natural gas liquids (NGLs) and nonhydrocarbon gases (e.g., carbon dioxide [CO_2] and water vapor) (EIA, 2023a). Natural gas is one of the major combustion fuels used throughout the country. It is mainly used to generate industrial and utility electric power, produce industrial process steam and heat, and heat residential and commercial spaces. The average gross heating value of natural gas is approximately 1,031 British thermal units per standard cubic foot (Btu/scf), typically varying from 950 to 1,050 Btu/scf.[b]

Natural gas is typically classified as being either conventional or unconventional, depending on the permeability of the formation within which it is found, the production technology used to secure it, the current economic environment, and the scale, frequency, and duration of production from the resource (EIA, 2023a; Krieg, 2018). Generally, conventional natural gas refers to natural gas found in highly permeable reservoirs, typically composed of sandstone or limestone, which allows for extraction to be completed in a relatively straightforward manner via vertical rather than horizontal drilling. Unconventional natural gas refers to natural gas

[b] The 1,031 Btu/scf average, also equivalent to 54.1 MJ/kg, is calculated using the high-heating value of natural gas at standard conditions of 60 °F and 1 atm.

found within low-permeability reservoirs; it is generally trapped within the pores (i.e., small, unconnected spaces) of rocks, which makes extraction more difficult and necessitates advanced drilling (e.g., directional or horizontal drilling) and well stimulation (e.g., hydraulic fracturing) techniques that can be energy intensive (BP, 2017).

Innovations in existing oil and gas exploration and production technologies have revolutionized unconventional natural gas production in the United States. The production of natural gas from unconventional resources has not only made up for declining conventional natural gas production but has also led to new levels of natural gas supply in the United States. This increased supply has contributed to an increase in the use of natural gas for power generation, manufacturing, transportation, and residential and commercial heating, as well as the availability of natural gas for export from the United States.

There are three primary types of unconventional natural gas:[c]

- **Shale Gas:** refers to natural gas found within shale rock formations, which consist of fine-grained sedimentary rock that forms when silt and clay-size mineral particles are compacted together (Zendehboudi and Bahadori, 2017). Shale rock formations can be easily broken into thinner, parallel layers of rock.
- **CBM:** refers to natural gas that is both generated and stored in coal beds. Originally extracted from coal mines to reduce the potential for explosions caused by an excess of CH_4 gas within the mine and subsequently disposed of, CBM now serves as an important source of energy. Producing CBM from deeper, denser coal formations often requires the use of hydraulic fracturing technology.
- **Tight Sands Gas:** refers to natural gas found in low-permeability, gas-bearing, fine-grained sandstones, or carbonates.

Shale rock formations can contain significant accumulations of natural gas and/or oil. These formations are often referred to as “plays” and can be found in nearly 30 U.S. states. Operators in the Barnett Shale formation, which is located in Texas and is one of the largest onshore natural gas plays in the United States, have been producing unconventional natural gas since the early 2000s (RRC, 2023). While operators in the Barnett Shale formation still produce a significant amount of unconventional natural gas, the Marcellus Shale formation—located in the Appalachian Region of the United States and spanning Ohio, Pennsylvania, and West Virginia—is currently the largest source of domestic unconventional natural gas from shale (EIA, 2023a).

Primary enabling technologies for accessing unconventional natural gas include hydraulic fracturing and horizontal drilling. Hydraulic fracturing (sometimes referred to as hydrofracking or simply fracking) is the process of pumping water mixed with a small amount of sand and other chemical additives (i.e., fracturing fluid) underground through a wellbore at a pressure

[c] There are other types of unconventional natural gas whose exploitation has not yet reached commercial scale. These include methane hydrate, which is a crystalline solid that consists of a methane molecule surrounded by a cage of interlocking water molecules. Methane hydrate is an "ice" that only occurs naturally in subsurface deposits where temperature and pressure conditions are favorable for its formation.

that is sufficient to cause a target rock formation to break (i.e., fracture) (USGS, 2019).[d] As the rock is fractured, natural gas that would have otherwise remained trapped is able to be released into a wellbore and returned to the surface (USGS, 2019).

The internal pressure caused by the fracturing of the rock formation also releases fluid, which travels to the surface through the wellbore. This fluid is commonly referred to as "flowback" or "produced water" and may contain the injected chemicals in addition to any naturally occurring materials found below the surface (e.g., brines, metals, radionuclides, and hydrocarbons). The fluid is typically stored on site at the well-pad in tanks or pits before it is treated and disposed of or recycled. In many cases, disposing of the fluid involves injecting it underground. In areas where underground injection is not an option, the fluid can either be reused or processed by a wastewater treatment facility and subsequently discharged into surface water.

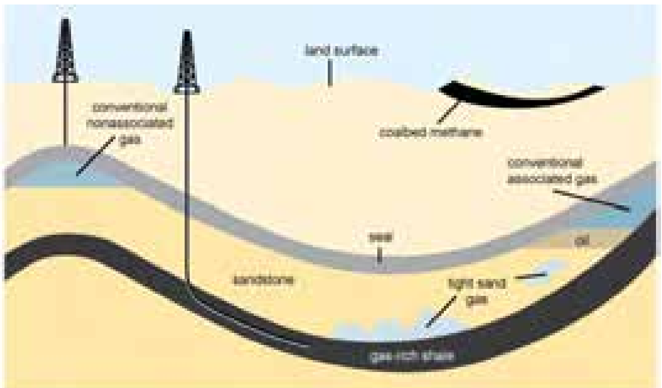
Hydraulic fracturing has been applied since the late 1940s when Standard Oil of Indiana (later known as Amoco) developed the technique and performed some of the first fracture treatments in the Hugoton Gas Field in Kansas (BP, 2017). While the use of hydraulic fracturing is not limited to wells that are horizontally drilled, the combination of horizontal drilling and hydraulic fracturing has increased the volume of domestic natural gas considered to be "technically recoverable" (i.e., able to be produced using currently available technology and industry practices regardless of any economic considerations).

The process of horizontal drilling involves first drilling a vertical well. Once a certain depth has been reached with the vertical well, the path of drilling is bent until the well begins to extend horizontally. Horizontal wells are not only longer than vertical wells, but the process is much more complex. A horizontal well is, therefore, generally more expensive to drill than a vertical well, but it is expected to produce more natural gas (EIA, 2018). As the horizontal section of a well, sometimes referred to as the directionally drilled section, can extend thousands of feet (ft).

Exhibit 1-1 provides a schematic of conventional natural gas and the various types of unconventional natural gas resources described previously (EIA, 2023a). Exhibit 1-2 provides a schematic of the hydraulic fracturing process (BP, 2017).

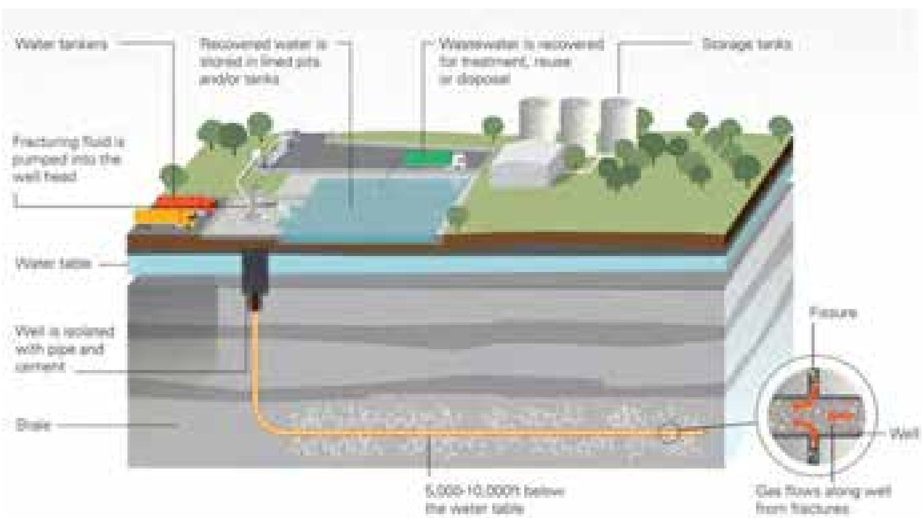
[d] The specific types of chemical additives used, and the proportions of each, depend on the type of rock formation that is being fractured. Additives function as friction reducers, biocides, oxygen (O_2) scavengers, stabilizers, and acids, all of which are necessary to optimize production. The composition of these fluids and the purposes of the additives are described in more detail in Chapter 4 – Water Use and Quality.

Exhibit 1-1. Schematic geology of natural gas resources



Source: EIA (2023a)

Exhibit 1-2. Schematic geology of natural gas resources (3D)



Permission pending from BP (2017)

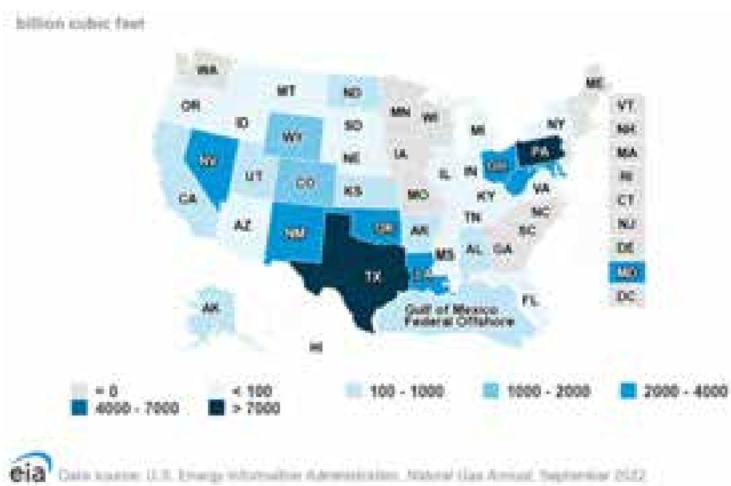
1.1.1 Liquefied Natural Gas

Liquefied natural gas is natural gas that has been cooled to a liquid state (approximately -260° F or -162° C). The volume of natural gas in a liquid state is about 600 times smaller than in a gaseous state. Liquification of natural gas makes it possible to transport natural gas to places where pipelines currently do not exist, or current pipeline infrastructure is unable to reach as well as for natural gas storage for end-use reliability. Liquefying natural gas is one way to allow markets that are far away from production regions to access natural gas. Once in liquid form, natural gas can be shipped to terminals around the world via ocean tankers and, in some cases, by LNG transport trailers (i.e., trucks). At these terminals, the LNG is returned to its gaseous state and transported by pipeline to distribution companies, industrial consumers, and power plants (DOE, 2021).

1.2 U.S. Natural Gas Resources

Annual U.S. production of dry natural gas was approximately 35.81 trillion cubic feet (Tcf) in 2022 (an average of about 98.11 billion cubic feet [Bcf] per day). Between 2021 and 2022, annual production of dry natural gas increased by about 4 percent from approximately 34.52 Tcf (an average of about 94.57 Bcf per day). With the exception of 2015–2016 and 2019–2020, annual domestic production of dry natural gas has increased year-over-year since 2005 as hydraulic fracturing combined with horizontal drilling of shale, sandstone, carbonate, and other geologic formations has continued. About 70 percent of the domestic dry natural gas production in 2021 was supplied by five of the United States' 34 natural gas-producing states.[e] States with a larger percentage share of total U.S. dry natural gas production in 2021 include Texas (24.6 percent), Pennsylvania (21.8 percent), Louisiana (9.9 percent), West Virginia (7.4 percent), and Oklahoma (6.7%) (Exhibit 1-3) (EIA, 2023a).

Exhibit 1-3. U.S. natural gas production by state in 2021



Source: EIA (2023a)

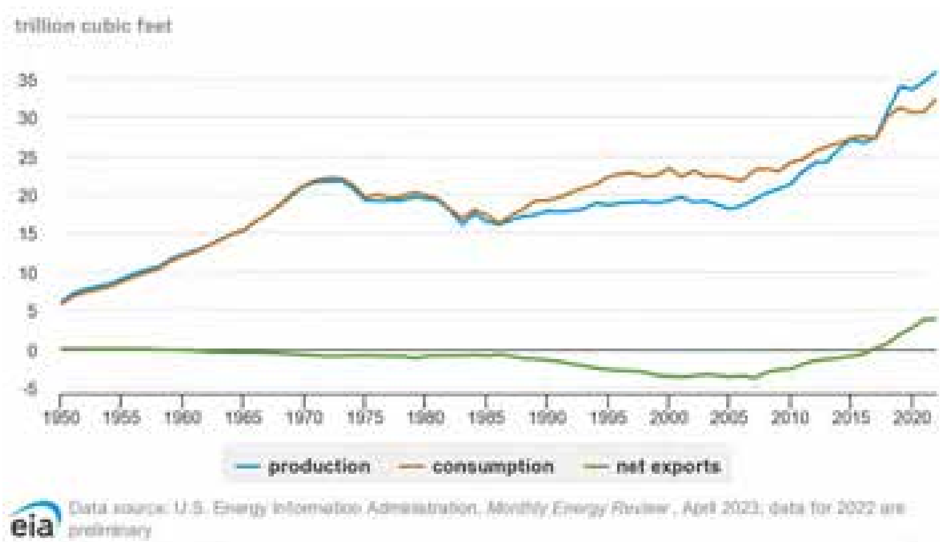
In 2022, production from coalbeds accounted for about 2 percent of U.S. dry natural gas production, and supplemental gaseous fuels accounted for about 0.2 percent. Supplemental

[e] 2022 state-level data was not available at the time this report was written. As such, 2021 state-level data is used above.

gaseous fuels include biogas (sometimes called renewable natural gas), synthetic natural gas, and other gases. Although most of the natural gas wells operated by the United States are located onshore, some wells are drilled offshore (i.e., into the ocean floor in waters off the coast of the United States). In 2022, offshore dry natural gas production was approximately equal to 0.80 Tcf, accounting for about 2.3 percent of total production. The majority—87.6 percent—of this production occurred in federally managed waters within the Gulf of Mexico (EIA, 2023b).

In addition to being a producer of natural gas, the United States is also a consumer and net exporter of natural gas. In 2022, the United States produced about 10.8 percent more natural gas than it consumed. While there was sufficient domestic production to meet our consumption requirements, the United States did import some natural gas, mostly from Canada. However, on a net basis, the United States was a net exporter of natural gas. Exhibit 1-4 highlights recent (2022) and historical (1950–2021) U.S. natural gas production, consumption, and net exports (EIA, 2023b).

Exhibit 1-4. U.S. natural gas consumption, dry production, and net exports (1950–2022)



Source: EIA (2023b)

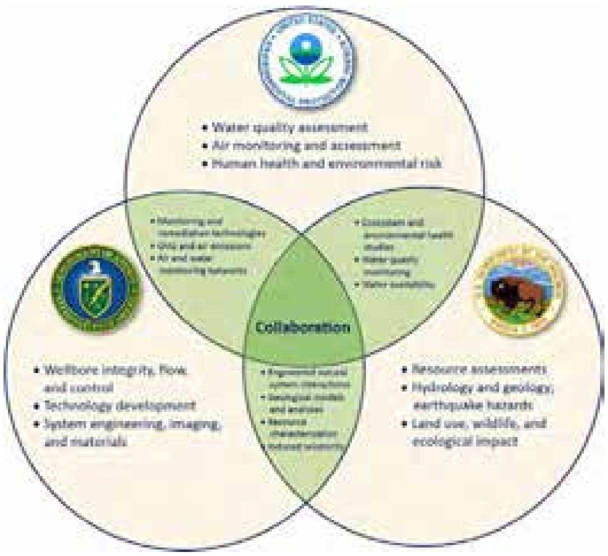
1.3 U.S. Regulatory Framework

The following sub-sections provide a review of both federal and state regulatory responsibilities related to the production, transportation, use, and export of domestic natural gas resources.

1.3.1 Federal

Multiple federal agencies have authority over the production of unconventional natural gas resources. Three of these agencies—DOE, the Department of the Interior (DOI), and the Environmental Protection Agency (EPA)—play a uniquely critical role as they are charged with monitoring, assessing, and reporting on various natural gas environmental impacts, such as those described in this report. Exhibit 1-5 describes the roles and responsibilities of these three agencies at a high-level in addition to the way they work together to inform policy-relevant science.

Exhibit 1-5. Key U.S. agencies and their roles in natural gas development and production



Source: DOE

The following subsections detail the specific roles and responsibilities of these agencies and, where applicable, their specific bureaus and offices. Exhibit 1-6 provides examples of the federal statutes applicable to unconventional natural gas development helping to guide the roles and responsibilities described.

Exhibit 1-6. Selected federal regulations that apply to unconventional oil and gas development

Statutes	Applicability
Clean Air Act (CAA)	Places requirements on air emissions from sources of emissions at well sites; addresses compliance with existing and new air regulations, often delegated to local and state agencies. Generally, there is no distinction made between conventional and unconventional wells under the CAA.
Comprehensive Environmental Response,	Only applies if hazardous substances besides crude oil or natural gas are released in quantities that require reporting. Natural gas releases do not require notification

Statutes	Applicability
Compensation, and Liability Act	under the Comprehensive Environmental Response, Compensation, and Liability Act, but other hazardous substances may be released in reportable quantities during natural gas production.
Clean Water Act (CWA)	Limits pollutants on produced water discharge under the National Pollutant Discharge Elimination System; stormwater runoff containing sediment that would cause a water-quality violation requires a permit under CWA decisions. Beneficial uses of surface waters are protected under Section 303.
Emergency Planning and Community Right-to-Know Act	Requires facilities storing hazardous chemicals above the threshold to report same and provide a Material Safety Data Sheet to officials and fire departments.
Endangered Species Act (ESA)	Prohibits federal agencies from taking any action that is likely to jeopardize the continued existence of any endangered or threatened species (listed species) or result in the destruction or adverse modification of such species' designated critical habitat (Section 7); prohibits the taking of a listed species (Section 9); allows the Fish and Wildlife Service and National Marine Fisheries Service to issue a permit, accompanied by an approved habitat conservation plan, that allows for the incidental, non-purposeful "take" of a listed species under their jurisdictions (Section 10).
National Environmental Policy Act (NEPA)	Requires analysis of potential environmental impacts of proposed federal actions, such as approvals for exploration and production on federal lands.
Oil Pollution Act	Identifies spill prevention requirements, reporting obligations, and response planning (measures that will be implemented in the case of release of oil or other hazardous substances).
Resource Conservation and Recovery Act	Addresses non-hazardous solid wastes under Subtitle D. The Solid Waste Disposal Act exempts many wastes produced during the development of natural gas resources, including drilling fluids and produced water. EPA determined that other federal and state regulations are more effective at protecting health and the environment.
Safe Drinking Water Act (SDWA)	Prevents the injection of liquid waste into underground drinking water sources through the Underground Injection Control (UIC) program. Fluids other than diesel fuel do not require a UIC permit. The UIC program gives requirements for siting, construction, operation, closure, and financial responsibility. Forty states control their own UIC programs.

1.3.1.1 Department of Interior

The DOI is a cabinet-level agency that manages America's vast natural and cultural resources through the operations of 11 technical bureaus. Of the DOI's bureaus, the Bureau of Land Management (BLM), the National Park Service (NPS), and the U.S. Forest Service (USFS) each have responsibilities related to the enforcement of regulations for unconventional natural gas wells drilled on public lands.

1.3.1.1.1 Bureau of Land Management

The BLM manages the U.S. government's onshore subsurface mineral estate—an area of about 700 million (MM) acres—from which sales of oil, gas, and natural gas liquids accounted for approximately 11 percent of all oil and 9 percent of all natural gas produced in the United States during fiscal year 2022.[f,g] About 23 of these 700 MM acres were leased to natural gas developers by the end of that year, and about 12.4 MM of those acres were producing natural gas in economic quantities (BLM, 2023).

From regulatory perspective, the BLM is responsible for 1) ensuring the environment of public lands remains protected and unaffected by natural gas production and other related activities and 2) for managing natural gas development on federally owned lands. BLM published a rule regulating natural gas fracking on public lands on March 26, 2015—this rule was rescinded on December 28, 2017 (Fitterman, 2021). On November 30, 2022, BLM proposed new regulations to reduce the waste of natural gas from venting, flaring, and leaks during oil and gas production activities on Federal and Indian leases (BLM, 2022). Key elements of the proposed rule include the following:

- Technology Upgrades: The rule would require the use of "low-bleed" pneumatic equipment as well as vapor recovery for oil storage tanks, where economically feasible. These requirements would reduce losses of natural gas from pneumatic equipment and storage tanks on federal and Indian leases.
- Leak Detection Plans: The rule would require operators to maintain a Leak Detection and Repair program for their operations on federal and Indian leases.
- Waste Minimization Plans: Requires the development waste minimization plans demonstrating the capacity of available pipeline infrastructure to take the anticipated associated gas production. The BLM may delay action on, or ultimately deny, a permit to drill to avoid excessive flaring of associated gas.
- Monthly Limits on Flaring: Places time and volume limits on royalty-free flaring. Importantly, this includes a monthly volume limit on royalty-free flaring due to pipeline capacity constraints—the primary cause of flaring from Federal and Indian leases.

It is important to note that drilling on federal or public lands is subject to oversight by federal agencies, and sections of the ESA may require that species of plants or animals not be threatened by the permitted drill site (NETL, 2019). Mandatory plans for mitigation and reclamation may be required to ensure that impacts on wildlife and habitat will be as minimal as possible (NETL, 2019).

1.3.1.1.2 U.S. Forest Service

The USFS is responsible for managing access to, and the development of, federal oil and natural gas resources on approximately one-third of the over 150 national forests and grasslands. The Federal Onshore Oil and Gas Leasing Reform Act of 1987 grants the USFS authority to decide if the lands reserved from the public domain can be leased for oil and gas. The USFS manages oil and gas activity according to the regulations at 36 CFR 228 Subpart E (USFS, 2023). The purpose of these specific regulations are to set forth rules and procedures through which use of the

[f] This area is held jointly by the BLM, USFS, and other federal agencies and surface owners
[g] October 1, 2021, through September 30, 2022.

federal surface lands in connection with operations authorized by the United States mining laws shall be conducted so as to minimize adverse environmental impacts.

1.3.1.1.3 National Park Service

Natural gas production and other related activities that will or do take place within the boundaries of America's national parks are managed by the NPS. Charged with protecting park resources and visitor values, the NPS helps to manage oil and gas operations following the 9B regulations. This set of regulations governs non-federal oil and gas activities and the conduct of final Environmental Impact Statement for units of the national park system where oil and gas production occur or are likely to occur in the foreseeable future (NPS 2023).

1.3.1.2 Environmental Protection Agency

Under the SDWA, EPA is charged with developing the minimum federal requirements for injection well practices to protect the public's health and prevent the contamination of underground sources of drinking water. EPA is also charged with regulating the air emissions covered under the CAA. EPA regulates several types of emissions relevant to the natural gas supply chain, including methane emissions, criteria air pollutant emissions, and water and soil pollutants. EPA's New Source Performance Standards (NSPS) under the CAA set the regulations for emissions sources from the oil and natural gas sector. Exhibit 1-7 illustrates the scope of NSPS established to-date and the way regulations have evolved in scope since 2012 (EPA, 2021).

Exhibit 1-7. Natural gas sources covered by EPA's proposed NSPS and emissions guidelines, by site

[illegible]	[illegible]	[illegible]			
		[illegible]	[illegible]	[illegible]	[illegible]
[illegible]					
[illegible]	✓	•	•	•	
[illegible]	✓			•	•
[illegible]	✓		•	•	•
[illegible]	✓			•	
[illegible]	✓	•	•	•	•
[illegible]	✓		•	•	•
[illegible]	✓	•	•	•	•
[illegible]	✓	•	•	•	•
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[illegible]	✓		•	•	•
[illegible]	✓			•	•
[illegible]	✓	•	•	•	•

[1]Covered for SO_2 only; [2]Covered for VOCs only

Source: EPA

EPA's Greenhouse Gas Reporting Program (GHGRP) requires reporting of GHG emissions data and other relevant information by large sources of emissions, including fuel and industrial gas suppliers and CO_2 injection sites (EPA, 2023). The data reported is available to businesses, stakeholders, and others interested in tracking and comparing the GHG emissions of facilities, identifying opportunities to reduce emissions, minimizing wasted energy, and saving money. The petroleum and natural gas industry is covered under Subpart W of EPA's GHGRP. Unconventional natural gas production is covered under the provisions for onshore production, natural gas processing, natural gas transmission, and LNG storage and import/export. Annual CO_2, CH_4, and nitrogen oxides (NOx) emissions must be reported separately for each of these segments.

EPA studied the relationship between hydraulic fracturing for oil and natural gas and drinking water resources (EPA, 2022a). The study includes a review of published literature, analysis of existing data, scenario evaluation and modeling, laboratory studies, and case studies. EPA released a progress report in December 2012, a final draft assessment report for peer review and comment in June 2015, and the final report in December 2016. The final EPA report concludes that hydraulic fracturing activities can impact drinking water resources under some circumstances and identifies factors that influence these impacts.

A core element of the SDWA UIC program is setting requirements for proper well siting, construction, and operation to minimize risks to underground sources of drinking water. The Energy Policy Act of 2005 excluded hydraulic fracturing (except when diesel fuels are used) for oil, natural gas, or geothermal production from regulation under the UIC program. This statutory language caused regulators and the regulated community alike to raise questions about the applicability of permitting practices. As a result, EPA developed revised UIC Class II permitting guidance specific to oil and natural gas hydraulic fracturing activities using diesel fuels (EPA, 2022a). Although developed specifically for hydraulic fracturing where diesel fuels are used, many of the guidance's recommended practices are consistent with best practices for hydraulic fracturing in general, including those found in state regulations and model guidelines for hydraulic fracturing developed by industry and stakeholders. Thus, states and tribes responsible for issuing permits and/or updating regulations for hydraulic fracturing will find the recommendations useful in improving the protection of underground sources of drinking water and public health wherever hydraulic fracturing occurs. The guidance outlines for EPA permit writers, where they are the permitting authority, 1) existing Class II requirements for diesel fuels used for hydraulic fracturing of wells, and 2) technical recommendations for permitting those wells consistently with these requirements (EPA, 2022a).

EPA completed a stakeholder engagement effort in 2019 that sought input on how the agency, states, tribes, and stakeholders regulate and manage wastewater from the oil and gas industry. EPA released a draft report in May 2019 that described what it heard during its engagement for this study (EPA, 2022a). EPA accepted public input on the draft report and, after considering this input, published a final report in May 2020 (EPA, 2020). In many regions of the United States, underground injection is the most common method of managing fluids or other substances from shale gas extraction operations. Management of flowback and produced water via underground injection is regulated under the SDWA UIC program. The CWA effluent guidelines program sets national standards for industrial wastewater discharge to surface waters and municipal sewage treatment plants based on the performance of treatment and control technologies. Effluent guidelines for onshore oil and natural gas extraction facilities prohibit the discharge of pollutants into surface waters, some permit exception may allow for discharge under unique conditions. On June 28, 2016, EPA promulgated pretreatment standards for the Oil and Gas Extraction Category (40 Code of Federal Regulations Part 435). These regulations prohibit discharge of wastewater pollutants from onshore unconventional oil and natural gas extraction facilities to publicly owned treatment works.[h]

On December 6, 2022, EPA issued a supplemental proposal to update, strengthen, and expand standards intended to significantly reduce emissions of GHG and other harmful air pollutants from the Crude Oil and Natural Gas source category (EPA, 2022b). First, EPA proposed standards for certain sources that were not previously addressed. Second, EPA proposed revisions that strengthen standards for sources of leaks, provide greater flexibility to use innovative advanced detection methods, and establish a super-emitter response program. Third, EPA proposed to modify and refine certain elements of the proposed standards in response to information submitted in public comments. Finally, EPA proposed details of the timelines and other implementation requirements that apply to states to limit CH_4 pollution from existing designated facilities in the source category under the CAA (EPA, 2022b). Evaluation of this proposed rule is still in progress.

1.3.1.3 Department of Energy

The NGA requires DOE to make public interest determinations on applications to export LNG to countries where the United States does not have existing free trade agreements requiring national treatment for trade in natural gas. The Office of Fossil Energy and Carbon Management's (FECM) natural gas import–export regulatory program is implemented by the Division of Regulation in the Office of Regulation, Analysis, and Engagement. Typically, the Federal Energy Regulatory Commission (FERC) has direct regulatory responsibility over the siting, construction, and operation of onshore LNG export facilities in the United States. In these cases, FERC leads the environmental impact assessments of proposed projects consistent with NEPA, and DOE is typically a cooperating agency as part of these reviews (DOE, 2023a). Similarly, for offshore LNG export facilities, the Department of Transportation's (DOT) Maritime Administration is responsible for environmental reviews, in coordination with the U.S. Coast Guard, guided by requirements in the Deepwater Port Act. Again, DOE is typically a cooperating agency in these reviews. In some limited circumstances, DOE is the lead agency for NEPA reviews related to proposed LNG exports.

FECM's Point Source Carbon Capture Division's research, development, demonstration, and deployment portfolio facilitates the development of technologies and infrastructure that improve performance, reduce costs, and scale the deployment of technologies to decarbonize the industrial and power sectors and remove CO_2 from the atmosphere. Within the natural gas supply chain, these efforts include research and commercial-scale demonstration of

[h] "Publicly owned treatment works" is a term used in the United States to designate a sewage treatment plant owned, and usually operated, by a government agency. In the United States, publicly owned treatment works are typically owned by local government agencies and are usually designed to treat domestic sewage and not industrial wastewater.

technologies that advance carbon capture and storage on natural gas-fired power plants and industrial natural gas combustion streams (DOE, 2023a).

FECM is working to support efforts to decarbonize LNG terminals through exploration of technical and economic feasibility of carbon capture on gas separation and combustion streams and the use of electric motor drives supplied by net-zero emissions electricity. Decarbonizing LNG terminals is a key part of the effort to reduce life cycle emissions associated with the export of natural gas to global allies.

FECM's Methane Mitigation Technologies Division aims to eliminate non-trivial fugitive and vented CH_4 emissions from the natural gas supply chain to reduce the climate impacts from the production and use of natural gas. The division is focused on developing accurate, cost effective, and efficient technology solutions and best practices to identify, measure, monitor, and minimize CH_4 emissions from these sources. DOE has funded several technology investigations through NETL that deal with produced water management and life cycle assessments of the natural gas value chain (DOE, 2023b).

DOE's shale gas research program brings together federal and state agencies, industry, academia, non-governmental organizations (NGOs), and national laboratories to develop technologies that enable safe, environmentally sustainable oil and gas production. DOE's shale gas research program is tasked with calculating the risks of oil and gas exploration and production undertakings.

On April 21, 2023, a Request for Information (RFI) was issued by FECM to obtain input to inform DOE's research and development (R&D) activities within the Office of Research and Development's Methane Mitigation Technologies Division and the Office of Carbon Management Technologies' Point Source Carbon Capture Division. In addition, such data and information could help inform the Office of Regulation, Analysis, and Engagement's capabilities to assess natural gas import and/or export applications. Through the RFI, DOE requested information on strategies and technologies that natural gas and LNG companies are deploying, or could deploy, to reduce GHG emissions and other air pollutants associated with natural gas delivered to liquefaction facilities, housed at liquefaction facilities, and being loaded, transported, and delivered to regasification facilities (DOE, 2023a).

1.3.1.4 Occupational Safety and Health

The Occupational Safety and Health Administration (OSHA) establishes standards, directives (instruction to OSHA staff), letters of interpretation, and national consensus standards that pertain to employee safety within the oil and gas extraction industry (OSHA, 2023). OSHA standards are in place to limit employee exposures to hazards present during oil and gas well drilling, servicing, and storage. Regulations and standards related to site preparation activities, which include leveling the site, trenching, and excavation, are covered under 29 CRF 1926, while all other aspects drilling and servicing operations are covered by 29 CFR 1910 (OSHA, 2023).

1.3.2 States

States have the power to implement their own requirements and regulations for natural gas drilling that are equivalent to or more stringent than established federal practices. [1]All states that produce natural gas have at least one agency charged with issuing new permits for production wells. While state requirements for permits can differ, any requirements set forth by federal regulations must be met for a state-level permit to be issued. Beyond issuing new permits for production states can also issue regulations, rules, and requirements for managing the potential environmental impacts of natural gas activities.

While regulations, rules, and restrictions vary by state in some cases the actions taken by one or a subset of states have helped to inform the regulations imposed by other states. This is true for states like Texas who were among the first to experience induced seismicity impacts from natural gas related activities. In an effort to provide the public with knowledge on the actions being taken to manage environmental impacts the following subsections provide a synopsis of regulations at the state level related to two areas of interest in this report – impacts to water and the induced seismicity associated with unconventional natural gas development.

Commented [HSAJ4]: Note for FECM: We pulled up information from the last iteration of the report in an effort to provide the 30,000 ft. view of state-level regulations. For some of the env. impacts areas (e.g., GHG emissions) we did not yet have information on state-level regulations. As you are reviewing this, could you please provide insight into whether you'd like us to structure this by "impact" wherein we would add sub-sections for the missing impacts or approach it in some other way.

1.3.2.1 Water

States have the primary responsibility for permitting oil and gas development and related water sourcing, but there is currently significant disparity in their approaches to regulating shale water requirements and associated impacts. A study by Resources for the Future (RFF) looked at regulations relevant to shale gas energy development and found markedly different water withdrawal policies across 30 of the states they surveyed, including those with major shale energy development (see Exhibit 1-8). The study found that for most of the 26 states with any water withdrawal permitting requirements, only half require permits for all withdrawals. Several states do not require permits at all, but only disclosure of water use over a certain threshold, as represented by the light purple states (Freyman, 2014). In addition, some states exempt oil and gas operators from permitting requirements for water withdrawals, including the following:

- Kentucky, which exempts the industry from both surface and groundwater reporting
- Texas, which requires permits for surface water withdrawals, but generally not for groundwater

[1] Zirogiannis et al. (2016) develop a framework for comparing states based on how intensely they regulate unconventional gas development.

Exhibit 1-8. Water withdrawal regulations by state

Used with permission from Richardson et al. (2013)

1.3.2.2 Induced Seismicity

State regulators have long been focused on identifying the precise location and magnitude of earthquakes and determining their cause. When earthquakes can be linked to wastewater injection, regulators respond by ordering operators to cease or limit either injection rates and/or water volumes in nearby wells (EPA UIC National Technical Workgroup, 2015). Many regulators also require that new injection wells avoid areas near known active faults. In Oklahoma, these techniques have effectively reduced the number of felt earthquakes.

Additional state requirements and activities associated with managing seismicity from include the following (Young et al., 2017):

- Searching the USGS seismic database for historical earthquakes within a circular area of 100 square miles around a proposed, new disposal well (~5.6-mile radius)
- Clarification of the Texas Railroad Commission's (RRC) authority to modify, suspend or terminate a disposal well permit, or modify operations if scientific data indicates a disposal well could be contributing to seismic activity
- Increased disclosure of reported volumes and pressures, at RRC's discretion
- RRC may require the provision additional technical information to demonstrate disposal fluid confinement.

Ohio has regulated seismic permits for injection wells for some time; obtaining a permit can require the following tests or evaluations of a proposed brine injection well be completed, in any combination that the chief deems necessary (Dade, 2017):

- Geological investigation of potential faulting within the immediate vicinity of the proposed injection well location, which may include seismic surveys or other methods determined by the chief to assist analysis.
- Permit conditions may include seismic monitoring, pressure fall-off tests, spinner tests, radioactive tracer, geophysical and electrical logs, and downhole pressure monitoring.

Restrictions may be placed on wells drilled near faults or areas known for seismic activity, in which seismic monitors must be installed for a specified period prior to completion operations (Dade, 2017).

The mitigation techniques employed by Ohio include the following:

- Direct communication with the operator is essential
- Discussion of seismic events and stages of the operation need to occur in real-time
- Spatial analysis and time correlation with completion data conducted during the operation

Mitigation techniques when induced seismicity occurs during hydraulic fracturing include the following:

- Change from zipper fracking to stack fracking
- At least 20% reduction in volume and/or pressure
- Switch to smaller sieve sizes for proppant

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2 Greenhouse Gas Emissions and Climate Change

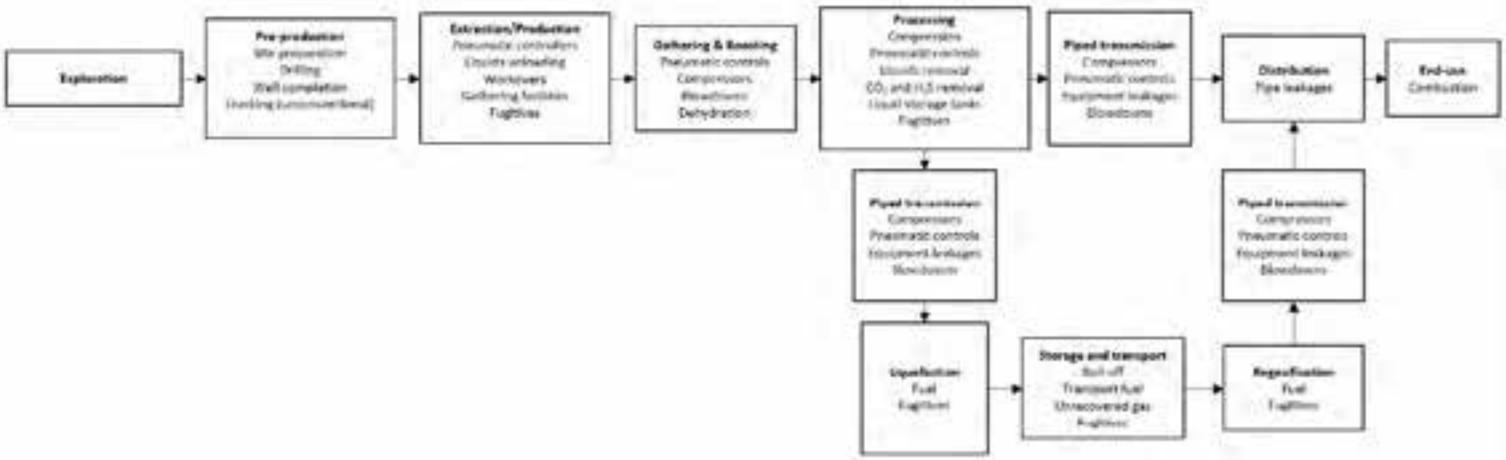
CO_2 and CH_4 emissions from the LNG life cycle vary widely across different regions and supply chains. This section presents a review of contemporary (2014 and after) life cycle analysis (LCA) as it pertains to LNG and natural gas GHG emissions.

2.1 Introduction

To account for all sources of GHG emissions in the natural gas supply chain, and to evaluate their relative contributions and mitigation opportunities, a systems-level perspective is both necessary and preferred. LCA is one type of systems-level approach available to account for the different sources of GHG emissions in the natural gas supply chain. LCA specifically considers the material and energy flows of an entire system "from cradle to grave"—where "cradle" refers to the extraction of resources from the earth, and "grave" refers to the final use and disposition of all products.

Depending on the type of LCA conducted, different system boundaries can be put in place to more accurately estimate the GHG emissions associated with natural gas. Generally, GHG emissions occur from the beginning of the natural gas supply chain (during exploration) through the end (during utilization). In some cases, an LCA may not consider every step of the natural gas supply chain within its analysis framework. This can happen for a variety of reasons, including lack of emissions data for a particular step or set of steps, or simply to focus specifically on the emissions associated with one particular step. Exhibit 2-1 provides an illustration of the natural gas supply chain with examples of key emissions sources.

Exhibit 2-1. Natural gas supply chain with examples of key emission sources



There are two primary approaches used to conduct natural gas LCA: 1) top-down and 2) bottom-up (Rutherford et al., 2021; Alvarez et al., 2018; Balcombe et al., 2016). A top-down approach a) measures the atmospheric concentrations of CH_4 as reported by fixed ground monitors, mobile ground monitors, aircraft, and/or satellite monitoring platforms; b) aggregates the results to estimate total GHG emissions; and c) allocates a portion of these total emissions to each of the different supply chain activities. A bottom-up approach measures GHG emissions directly from each source of emissions, then aggregates and extrapolates these measurements to estimate emissions for an entire region or process. Both approaches have advantages and disadvantages.

For example, several studies (see Rutherford et al., 2021; Alvarez et al., 2018; Balcombe et al., 2016) have noted that top-down approaches may lead to a general upward bias in emissions reporting while bottoms-up approaches may lead to a general downward bias in emissions reporting. There are several factors that may lead to these biases, which can be generally explained as follows:

- Top-down approaches sometimes fail to distinguish between different sectors. For example, aircraft that are used to collect emissions data for a particular area may struggle to distinguish between the CH_4 emissions coming from a natural gas processing facility in the area from those coming from a nearby dairy farm. This can lead to incorrect contributions of total CH_4 emissions to specific natural gas activities.
- Bottom-up approaches sometimes fail to capture "super emitters"—a small number of facilities (or types of equipment) that emit disproportionately large quantities of emissions. Because bottom-up approaches measure emissions from individual sources and because super emitters, by definition, represent only a small proportion of the total number of facilities (or equipment) represented within the natural gas supply chain, it can be challenging to accurately capture the contributions of super emitter activity to total emissions.

EPA estimates oil and natural gas CH_4 emissions in the annual Greenhouse Gas Inventory (GHGI) it produces. The GHGI uses a bottom-up approach to estimate national CH_4 emissions. Alvarez et al. (2018) note that in many bottom-up approaches to modeling, operator cooperation is required to obtain site access for accurate emissions measurements. Operators with lower-emitting sites are plausibly more likely to cooperate with such studies and workers are plausibly more likely to be careful to avoid errors or fix problems when measurement teams are on site or about to arrive, which could lead to a downward bias in estimates of potential emissions (Rutherford et al., 2021; Alvarez et al., 2018; Balcombe et al., 2016).

Another key difference in LCA methodology or assumptions that can lead to differences in LCA outputs (i.e., estimates of emissions) is tied to which climate-forcing impacts of CH_4 are used (Balcombe et al., 2016). CH_4 emissions have a large, short-term and climate-forcing impact[a]

[a] Climate or radiative forcing, a measure, is defined by the Intergovernmental Panel on Climate Change (IPCC) as the influence a given climatic factor has on the amount of downward-directed radiant energy impinging upon Earth's surface.

compared to CO_2. Typically, studies use global warming potential (GWP) to compare the climate impact of emissions of different GHGs such as CH_4 with CO_2.

The GWP is defined as a measure of how much energy the emissions of 1 ton of a gas will absorb over a given period, relative to the emissions of 1 ton of CO_2 (Balcombe et al., 2016). The Intergovernmental Panel on Climate Change (IPCC) progressively raised the GWP for CH_4 to 28 over a 100-year period and 84 over a 20-year period in their Fifth Assessment Report (AR5) published in 2014 (Stern, 2022). IPCC's Sixth Assessment Report (published in 2021) raised the GWP of CH_4 to 29.8 over a 100-year horizon but reduced the 20-year horizon factor to 82 (Stern, 2022). Adding climate feedback mechanisms and oxidation, these figures were increased to 36 and 87.15, respectively in the IPCC's Sixth Assessment Report.

To illustrate, if the GWP of CH_4 for a time horizon of 100 years is 36, this means that a pulse emission of CH_4 absorbs 36 times more energy than CO_2 over 100 years, on average. Note that the GWP of CH_4 for a time horizon of 100 years does not give any information on the climate forcing of CH_4 at the end of the 100 years; it gives only the average impact across the 100 years. It is important to consider which GWP is used when analyzing the outputs of an LCA, particularly when comparing the outputs of two or more LCAs (Balcombe et al., 2016).

2.2 Federally-Funded LCA

NETL has used LCA to calculate the environmental impacts of natural gas production and use for the generation of electric power for nearly a decade (NETL, 2023). Their work has been documented in a series of reports produced between 2010 and 2019.[b] Together, these reports provide in-depth assessments of the potential GHG emissions resulting from upstream unconventional natural gas production in the United States (NETL, 2019a). In addition to its characterization of domestic upstream natural gas, NETL also developed life cycle data for exported LNG, including the GHG emissions from liquefaction, ocean transport, regasification, and combustion for electricity generation (NETL, 2019b).

The GHG emissions results recorded in the NETL 2019 report considers five stages of the natural gas supply chain, which are visualized in Exhibit 2-2 (NETL, 2019a):

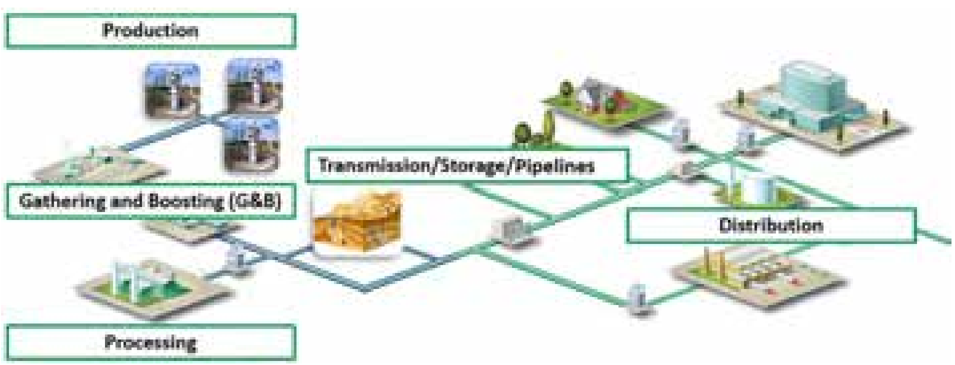
1. **Production:** Sources of emissions include the gas vented from pneumatically controlled devices and fugitive emissions from flanges, connectors, open-ended lines, and valves. When vapor recovery units are feasible, vented gas is captured and flared; otherwise, vented gas is released to the atmosphere. Production operations also include the combustion of natural gas and diesel in compressors and other equipment.
2. **Gathering and Boosting (G&B):** Natural gas G&B networks receive natural gas from multiple wells and transport it to multiple facilities. G&B sites include acid gas removal, dehydration, compressors operations, pneumatic devices, and pumps.
3. **Processing:** A natural gas processing facility removes impurities from natural gas, which improves its heating value and prepares it for pipeline transmission. Natural gas

[b] The GHG results in the NETL (2019) report supersede the GHG results in the previous NETL reports.

processing facilities include acid gas removal, dehydration, hydrocarbon liquids removal, and compression operations.

4. **Transmission Stations, Storage Facilities, and Transmission Pipelines:** A natural gas transmission system is a network of large pipelines that transport natural gas from processing facilities to the city gate (the point at which natural gas can be consumed by large-scale consumers or transferred to local distribution companies). Transmission stations are located along natural gas transmission pipelines and use compressors to boost the pressure of the natural gas.
5. **Distribution:** Natural gas distribution networks transport natural gas from the city gate to commercial, residential, and some industrial consumers. This analysis uses the distribution portion of the supply chain only for the upstream functional unit; distribution is not necessary for the functional unit of electricity in which natural gas power plants receive natural gas directly from transmission pipelines.

Exhibit 2-2. Supply chain stages that compose the overall LCA boundary



The flexible, consistent framework of NETL's LCA model allows different natural gas sources to be compared on a common basis (per megajoule [MJ] of delivered natural gas). In the NETL (2019a) report, five types of natural gas are considered:

1. **Conventional natural gas** is natural gas extracted via vertical wells in high permeability formations that do not require stimulation technologies for primary production.
2. **CBM** is extracted from coal seams and requires the removal of naturally occurring water from the seam before natural gas wells are productive.
3. **Shale gas** is extracted from low permeability formations and requires hydraulic fracturing and horizontal drilling.
4. **Tight gas** is extracted from non-shale, low permeability formations and requires hydraulic fracturing and directional drilling.
5. **Associated gas** is found with petroleum (either dissolved in oil or in a gas cap in a petroleum formation) and is produced by oil wells.

In its 2019 LCA analysis of the natural gas supply chain, NETL used the GWP reported in the IPCC AR5 (IPCC, 2013). Other key input data was sourced from EPA's GHGRP, Drilling Info (DI Desktop), and EIA. Results from the 2019 NETL LCA analysis performed suggested the following (NETL, 2019a):

- The life cycle GHG emissions associated with the U.S. natural gas supply chain were 19.9 grams (g) of carbon dioxide equivalents (CO_2e) per MJ of natural gas delivered (with a 95% mean confidence interval of 13.1–28.7 g CO_2e per MJ).
- The top contributors to CO_2 and CH_4 emissions were combustion exhaust and other venting from compressor systems. Compressor systems are prevalent in most stages of the natural gas supply chain and as such were key contributors to the total life cycle emissions estimated.
- Emission rates are highly variable across the entire supply chain. According to the study (NETL, 2019), the national average CH_4 emissions rate was 1.24 percent, with a 95 percent mean confidence interval ranging 0.84–1.76 percent.

Exhibit 2-3 shows the upstream GHG emissions from the different parts of the natural gas supply chain (NETL, 2019a). In Exhibit 2-4, the blue bars represent CO_2 emissions, the green bars represent CH_4 emissions, and the orange bars represent nitrous oxide (N_2O) emissions (NETL, 2019a). The vertical black lines in Exhibit 2-3 and Exhibit 2-4, respectively, represent the error bars in this analysis, and the shaded grey area represents the 95 percent mean confidence interval (NETL, 2019a).

Exhibit 2-3. Life cycle CH_4 emissions from the U.S. natural gas supply chain

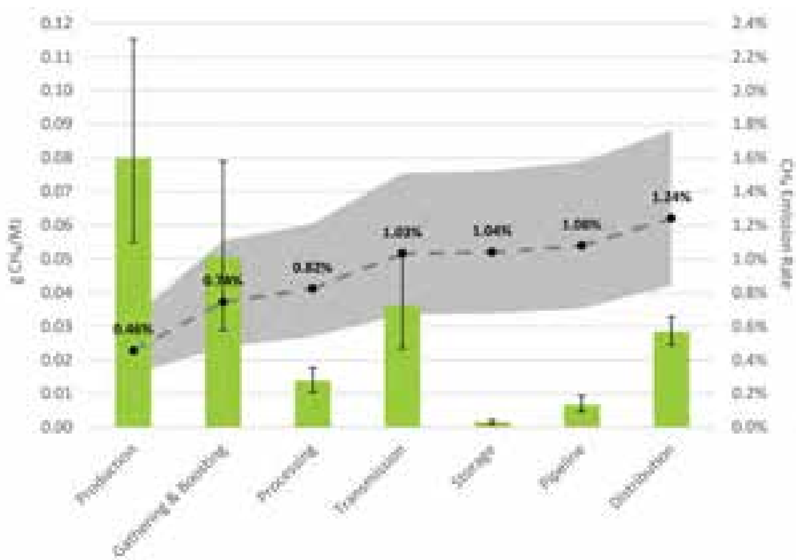
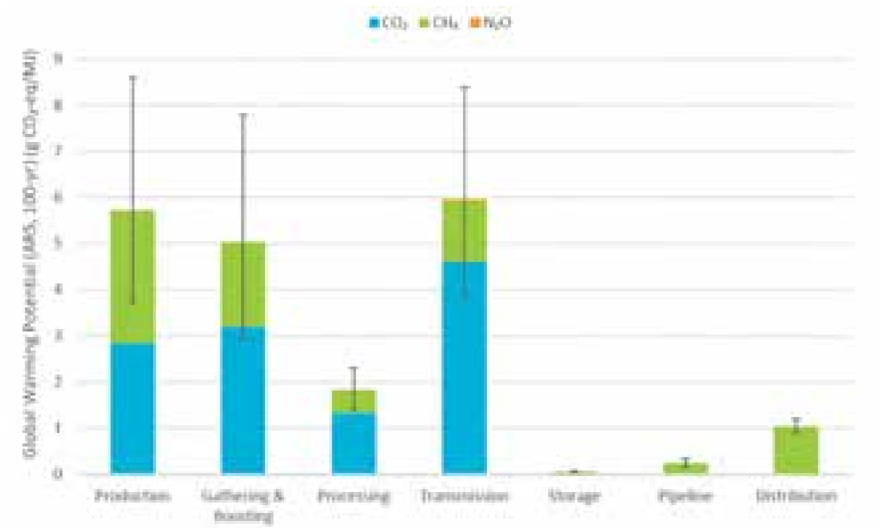


Exhibit 2-4. Life cycle GHG emissions for the U.S. natural gas supply chain

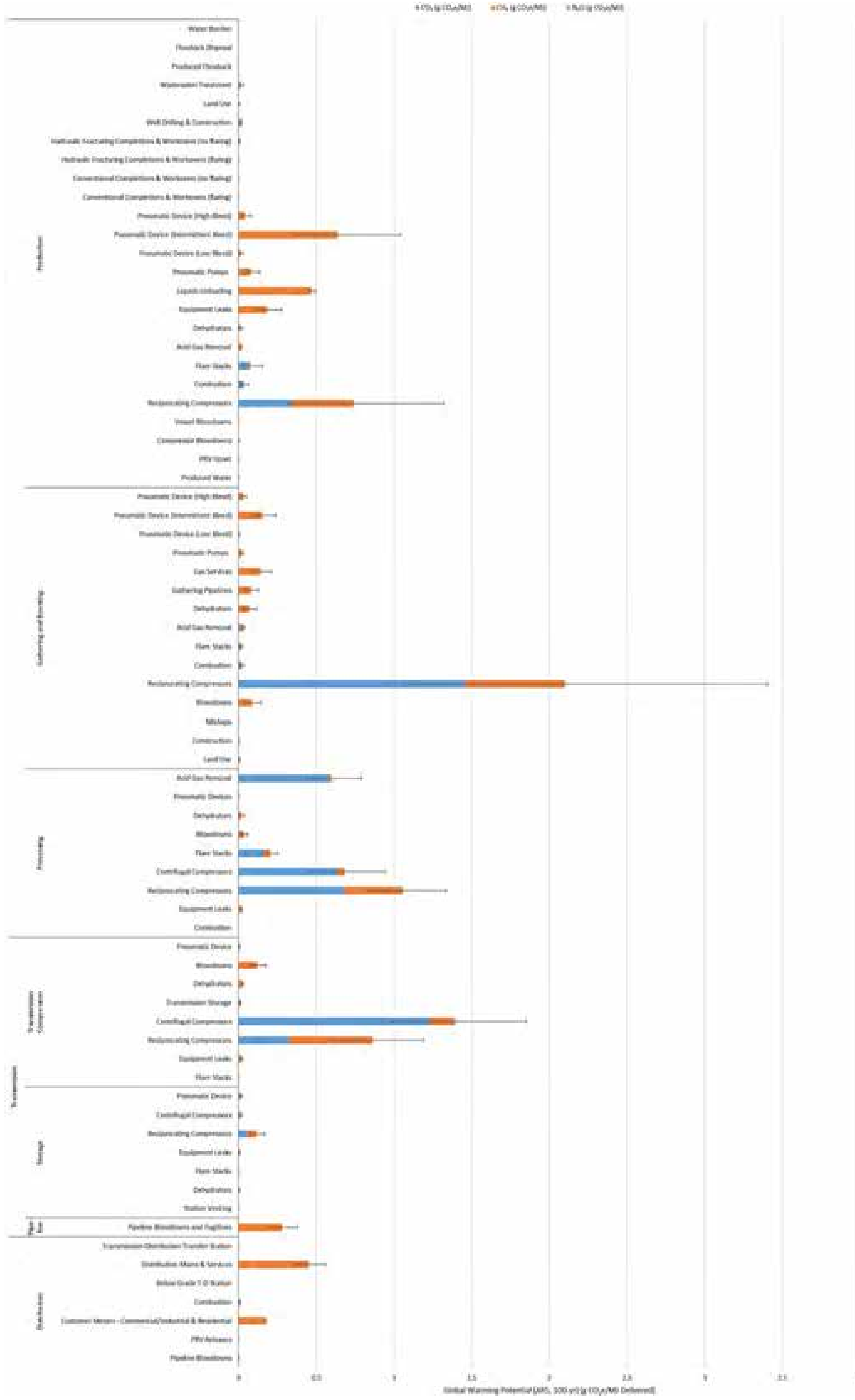


Key drivers of GHG emissions results for the entire natural gas supply chain are illustrated in Exhibit 2-5 (NETL, 2019a). Pneumatic devices and compression systems represent a significant portion of the total life cycle GHG emissions associated with the natural gas supply chain (NETL, 2019a). Pneumatic devices are used to operate level controllers, valves, and other equipment at natural gas facilities. According to EPA's GHGI, production pneumatics emitted 1,060 kilotons of CH_4 in 2017, accounting for 16 percent of the total CH_4 emissions from the natural gas supply chain. Pneumatic device activity is concentrated at production facilities and there were 833,000 pneumatic devices used by U.S. production facilities in 2019 (NETL, 2019a).

Natural gas is compressed for transport from processing facilities to end-consumers. As such, upstream GHG emissions are sensitive to pipeline distances and the number of compressors along these pipelines that the natural gas must pass through. The energy intensity of compression and the fugitive CH_4 emissions from compressors both contribute to upstream GHG emissions (NETL, 2019a).

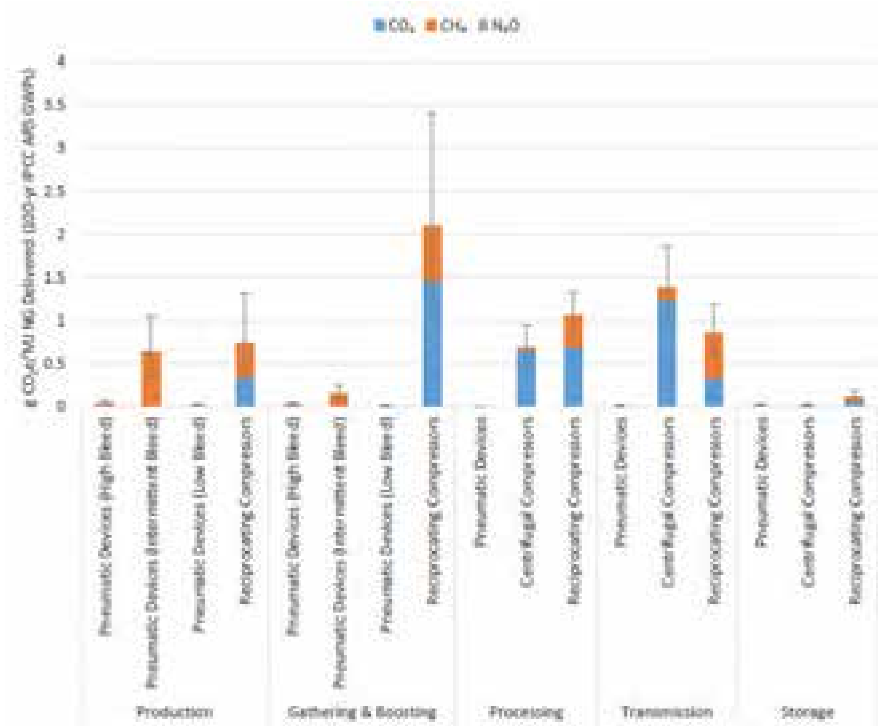
In addition to being a source of CH_4 emissions, compressors are also a source of CO_2 emissions. Most compressors in the U.S. pipeline transmission network are powered by natural gas that is withdrawn from the pipeline itself. Electric motors are not widely used by natural gas pipelines but are installed where local emission regulations limit the use of internal combustion engines or where inexpensive electricity is available. Nationwide in 2017, 6 percent of compressor stations were powered by electricity, 77 percent were powered by natural gas, and 17 percent were dual gas and electric (NETL, 2017).

Exhibit 2-5. U.S. average for 2017—detailed GHG emission sources for the U.S. natural gas supply chain (gCO_2e/MJ)



Two sources of CH_4 emissions from compressor systems include 1) CH_4 that slips through the compressor uncombusted into the exhaust stream and 2) CH_4 that escapes through compressor seals or packing. Natural gas systems use both centrifugal and reciprocating compressors. Centrifugal compressors are more appropriate for pressure boosting applications in steady-state applications (such as with a transmission pipeline), while reciprocating compressors are more appropriate when gas flow is variable and when large increases in pressure are required. Centrifugal compressors are typically driven by gas-fired turbines but, in some instances, are driven by an electric motor. Reciprocating compressors are driven by gas-fueled engines. Exhibit 2-6 illustrates the emissions associated with pneumatic devices and compressors.

Exhibit 2-6. GHG emissions from pneumatic devices and compressors across the NG supply chain (gCO_2e/MJ)



For all natural gas production types, the GHG emissions results produced by an LCA are sensitive to the following factors:

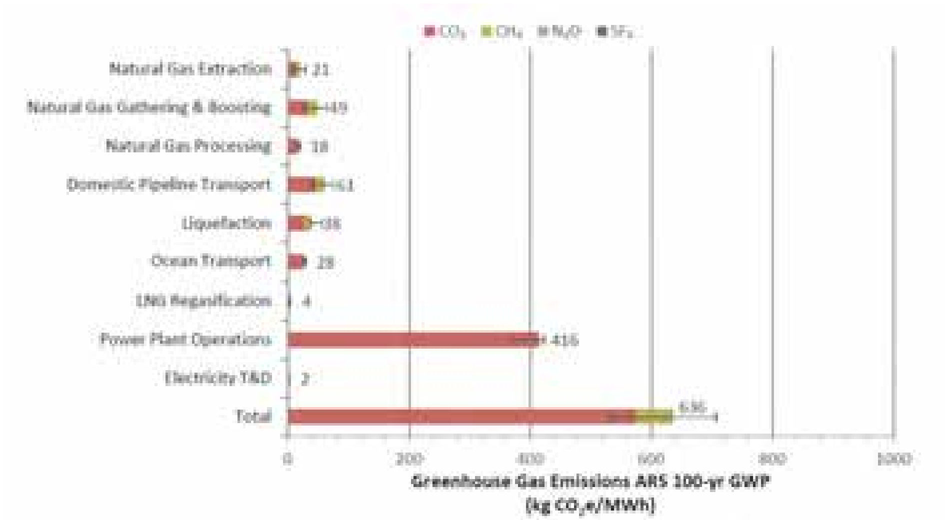
- Estimated ultimate recovery
- Regional natural gas composition differences (dry versus sour gas)

- Compression energy requirements and type
- Pneumatic device type, frequency, and number of devices per operation

In addition to its characterization of domestic upstream natural gas, NETL also developed life cycle data for exported LNG, including the GHG emissions from liquefaction, transport, regasification, and combustion for electricity generation (NETL, 2019b).

The NETL (2019b) report that analyzed the lifecycle emissions of exporting U.S. LNG to Europe yielded the emissions results (assuming end-use in electricity generation) detailed in Exhibit 2-7.

Exhibit 2-7. GHG emissions from exporting LNG from the United States to Europe



Littlefield, Rai, and Skone (2022) show that geography matters in terms of the GHG emissions estimated for the U.S. natural gas supply chain—where natural gas is produced and ultimately used plays a tremendous role in the total amount of GHG emissions estimated for the supply chain. Accordingly, a national average value is not necessarily an adequate representation of an individual (source to sink) natural gas supply chain. Littlefield, Rai, and Skone (2022) provide a detailed life cycle perspective on GHG emissions variability where natural gas is produced and where it is delivered. They disaggregate transmission and distribution infrastructure into six regions, balance natural gas supply and demand locations to infer the likely pathways between production and delivery (estimated via modeling as actual tracking of natural gas from well to customer is not technically feasible) and incorporate new data on distribution meters. They find the average transmission distance for U.S. natural gas is 815 kilometers (km) but ranges 45–3,000 km across estimated production-to-delivery pairings examined (Littlefield, Rai, and Skone, 2022). In terms of total GHG emissions, their results suggest the delivery of 1 MJ of natural gas to the Pacific region has the highest mean life cycle GHG emissions (13.0 g CO_2e/MJ) and the delivery of natural gas to the Northeastern region of the United States has the lowest mean life cycle GHG emissions (8.1 g CO_2e/MJ).

In 2020, NETL collaborated with industry and published an analysis of Our Nation's Energy Future's (ONE Future) portfolio of assets (Rai et al., 2020). ONE Future is a natural gas industry partnership dedicated to improving the efficiency of the domestic natural gas supply chain. ONE Future represents 1–13 percent of total throughput in the respective segments of the natural gas industry supply chain. The expected life cycle CH_4 emission rate for ONE Future average natural gas is 0.76 percent (with a 95 percent mean confidence interval ranging 0.49–1.08 percent).

The expected life cycle CH_4 emission rate for the U.S. average scenario is 1.06 percent. In terms of IPCC 100-year GWP, the ONE Future and U.S. average scenarios emit 9.7 and 14.1 g CO_2e/MJ of delivered natural gas, respectively.

2.3 Other Natural Gas Analyses

Balcombe et al. (2016) document the wide range of CH_4 emissions estimates across the natural gas supply chain. Estimates of combined CH_4 and CO_2 emissions range 2–42 g CO_2e/MJ. Significant drivers of this wide range of projections are 1) the emissions associated with upstream natural gas production, and 2) whether the natural gas is ultimately converted to LNG or not. This sub-section explores these different segments of the supply chain.

2.3.1 Natural Gas Production Analyses

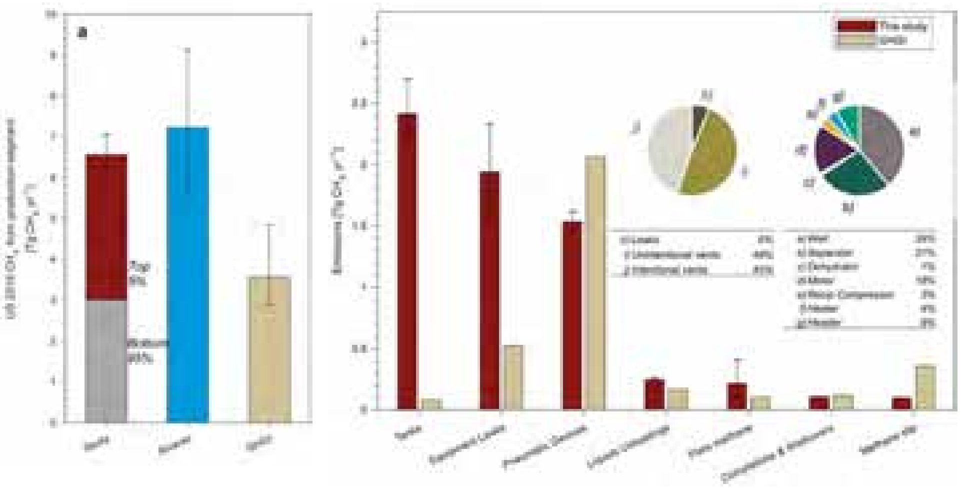
As noted above, EPA estimates oil and natural gas CH_4 emissions in the annual GHGI it produces. The GHGI uses a bottom-up approach to estimate national CH_4 emissions. Several studies have found that CH_4 emissions from the natural supply chain are about 1.5–2.5 times the amount reported in EPA's GHGI (Rutherford et al., 2021; Alvarez et al., 2018; Balcombe et al., 2016). Much of the discrepancy can be attributed to differences in the analyses performed for the production segment of the natural gas supply chain where super emitters and emissions-intensive equipment are both prevalent (Rutherford et al., 2021; Alvarez et al., 2018; Balcombe et al., 2016).

To isolate specific sources of disagreement between EPA's GHGI and other studies, Rutherford et al. (2021) reconstructed EPA's GHGI emission factors, beginning with the underlying datasets, and uncovered some possible sources of disagreement between inventory methods and top-down studies. The adjusted emissions factors are direct inputs in the Rutherford et al. (2021) study outputs. Rutherford et al. use a bottom-up measurement approach, yet the approach differs from the GHGI in that it applies a bootstrap resampling statistical approach to allow for inclusion of infrequent, large emitters, thereby addressing the issue of super-emitters in a more robust way.

Rutherford et al. (2021) estimate the mean, production-normalized emissions rate from the production segment as 1.3 percent (1.2–1.4 percent at 95 percent confidence interval, based on gross natural gas production of 32 Tcf and an average CH_4 content of 82 percent), slightly lower than Alvarez et al., 2018) who estimate it at 1.4 percent. Rutherford et al. (2021) estimate mean natural gas production-segment CH_4 emissions as equal to 6.6 teragrams (Tg) per year (6.1–7.1 Tg per year, at 95 percent confidence interval). Both the results of Rutherford et al. (2021) and Alvarez et al. (2018) are approximately two times larger than estimates of the 2015 EPA GHGI, which suggests that 3.6 Tg of emissions per year (year 2015 data, excludes offshore systems) come from the natural gas production segment.

Given that the Rutherford et al. (2021) results match the Alvarez et al.'s (2018) site-level results, the former concludes that the divergence between the GHGI and top-down/site-level studies is not likely to be due to any inherent issue with the bottoms-up approach. A results comparison of the Rutherford et al. (2021) study, the Alvarez et al. (2018) study, and 2015 EPA GHGI data can be found in Exhibit 2-8.

Exhibit 2-8. Comparison of GHG emissions results from Rutherford et al., Alvarez, et al., and EPA GHGI



Note: "This study" and "Study" labels on the x-axis refer to Rutherford et al. (2021)

Used with permission from Rutherford et al. (2021)

In April 2023, EPA released a report titled Inventory of U.S. Greenhouse Gas Emissions and Sinks, 1990-2021 (EPA, 2023). The results from this report allow comparison of EPA GHGI results over time, by segment of the natural gas supply chain (Exhibit 2-9).

Exhibit 2-9. EPA GHGI CH_4 emissions from natural gas systems (kt)

Segment	1990	2005	2017	2018	2019	2020	2021
Exploration	119	358	49	94	75	9	7
Production	2,311	3,495	3,697	3,823	3,739	3,475	3,360
Onshore Production	1,403	2,464	2,139	2,246	2,122	1,923	1,787
Gathering and Boosting	739	958	1,533	1,547	1,591	1,520	1,548
Offshore Production	170	73	26	30	25	32	24
Processing	853	463	460	483	506	495	510
Transmission and Storage	2,288	1,580	1,460	1,538	1,583	1,625	1,590
Distribution	1,819	1,018	561	557	554	553	548
Post-Meter	290	344	424	445	457	463	463
Total	7,680	7,260	6,652	6,939	6,914	6,619	6,478

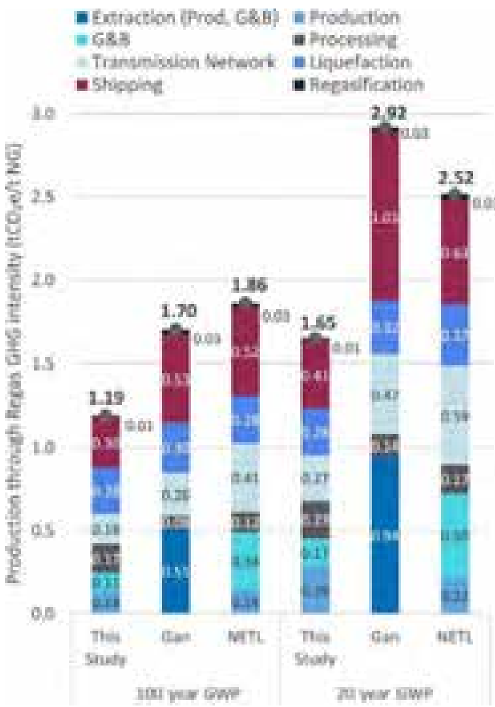
Note: To enable results comparison between Exhibit 2-8 and this exhibit, it is important to note the following conversion: 1 Tg of CH_4 is equal to 1,000 kt of CH_4.

2.3.2 LNG Studies

Relative to traditional natural gas supply chains where pipelines are the primary means by which natural gas is transported, LNG supply chains also involve liquefaction, shipping, and regasification stages—each of these stages drive even greater variability in emissions profiles in LCA studies. A review of 37 global LNG supply scenarios between the United States and China by Gan et al. (2020) concluded that GHG emissions intensities varied by about +/- 150 percent. Abrahams et al. (2015) note that emissions from the shipping of LNG exports from the United States to ports in Asian and European markets account for only 3.5–5.5 percent of precombustion life cycle emissions; hence, shipping distance is not a major driver of GHGs in the LNG supply chain.

At the end of 2020, Cheniere Energy was the largest exporter of LNG from the United States in terms of volume. Roman-White et al. (2021) developed an LCA framework to estimate GHG emissions representative of Cheniere's LNG supply chain, considering both upstream and downstream sources of emissions from Cheniere's Sabine Pass Liquefaction facility, using supplier-specific data collected from wellhead through ocean transport. Roman-White et al. (2021) compare the GHG emissions intensity of Cheniere LNG to two similar assessments of emission intensity from U.S. LNG transported to China (Gan et al., 2020; NETL, 2019b). The results of their comparison are illustrated in Exhibit 2-10.

Exhibit 2-10. Comparison of GHG emissions results from Roman-White et al., Gan et al., and NETL



Used with permission from Roman-White et al. (2021)

The NETL (2019b) LNG study uses more recent production emission data (2016 data) than Gan et al. (2020). The NETL (2019b) study is based on natural gas production in Appalachia with relatively low emissions intensity. The NETL analysis differs from the Roman-White et al. (2021) study primarily in the intensity of the G&B and transmission stages, which are driven by differences in individual facility performance.

When modeling transmission compression, the NETL (2019b) study assumes a factor of 0.97 horsepower-hour (HPh)/thousand cubic feet (Mcf) to estimate the transmission station throughput (derived from NETL-published parameters). The average ratio of HPh to Mcf of throughput, from Cheniere Energy's known suppliers (used in the Roman-White et al. study) is 0.27 HPh/Mcf, which is based on supplier data collection completed. For modeling gas from other transmission operators, the GHGRP does not publicly provide the throughput of compressor stations. The Roman-White et al. (2021) study assumes 0.29 HPh/Mcf based on data reported by EIA.

The higher factor used by the NETL (2019b) study results in increased modeled fuel consumption across the transmission network. The Roman-White et al. liquefaction GHG intensity is 8–13 percent less than the intensity estimated by Gan et al. and is comparable to the NETL (2019) study estimate on a 100-year basis. The Roman-White et al. (2021) study concludes ocean transport stage emission intensity is 42–60 percent less than the transport emission intensity of Gan et al. (2020), and 35–42 percent less than that of the NETL (2019b) study.

Jordaan et al. (2022) estimate global average life cycle GHG emissions from the delivery of gas-fired electricity to be 645 gCO_2e per kilowatt hour (kWh) (334–1,389 gCO_2e per kWh), amounting to 3.6 gCO_2e yr−1 in 2017 (10 percent of energy-related emissions). This result is within range of the results obtained by Roman-White et al. (2021), who report life cycle GHG emissions of 524 gCO_2e kWh for electricity in China from LNG supplied by U.S. LNG exporter Cheniere, and 636 gCO_2e per kWh reported by NETL (2019b). Exhibit 2-11 summarizes these results.

Exhibit 2-11. LCA results comparison of LNG-derived electricity

LNG LCA Study	Mean gCO_2e per kWh
NETL (2019b)	636
Roman-White et al. (2021)	524
Jordaan et al. (2022)	645

In summary, whether upstream natural gas GHG emissions are analyzed in isolation, or analyzed together with downstream LNG processes, the primary source of difference in the GHG results of contemporary literature comes from the upstream natural gas extraction and G&B portions of the natural gas supply chain.

2.4 Mitigation Measures

There are several mitigation measures used to address the GHG emissions discussed in this chapter, including improved GHG measurement capabilities, equipment upgrades, and process optimization.[a]

Compressor seals include wet seals used by centrifugal compressors and rod packing used by reciprocating compressors. Wet seals surround the rotating shaft of a centrifugal compressor with oil, which prevents gas leakage from the compressors. The oil used by wet seals must be continuously regenerated, which releases CH_4 into the atmosphere. By replacing wet seals with mechanical dry seals, the CH_4 emissions from centrifugal compressors can be reduced.

Reciprocating compressors prevent CH_4 leakage by encasing each compressor rod with a set of oil-coated, flexible rings. Proper maintenance and routine replacement of these rings prevents unnecessary leakage of CH_4. Storage tanks hold flowback water and liquid hydrocarbons recovered from the production stream. Variable loading levels and temperatures cause the venting of CH_4 and other gases from these tanks. By installing vapor recovery units on storage tanks, producers can more effectively reduce emissions from natural gas production. The

[a] Examples of equipment upgrades in this context include compressor seals, reciprocating compressors, and pneumatic controls.

captured emissions can be combusted on site to provide process energy, or they can be channeled to the sales stream.

Pneumatic controllers use gas pressure to open and close valves throughout a natural gas production and processing system. Natural gas is commonly used to pressurize pneumatic control systems. The bleeding of natural gas from pneumatic controllers leads to venting CH_4 to the atmosphere. The GHG impact of pneumatic control systems can be reduced by installing pneumatic systems that use pressurized air instead of pressurized natural gas.

The practice of reduced emissions completions (RECs) utilizes equipment that allow the capture of gas during flowback, either to be sent to the product line or, if this is not feasible, to be flared. However, regulations also mandate emission reductions from pneumatically controlled valves and compressor seals, which are two types of emission sources common to conventional and unconventional natural gas technologies. The data suggest that the use of this equipment reduces completion emissions by approximately 75−99 percent. For the most established unconventional gas industry, the United States, the use of RECs is compulsory by law. REC implementation has shifted the emissions from CH_4 to CO_2 and did reduce GHG intensity from a global warming perspective (Balcombe, 2016; Balcombe, 2018).

A 2020 report produced by NETL – Littlefield et al. (2020) - notes that compressed-air pneumatics are a mature technology that reduces CH_4 emissions from pneumatic systems. The technology replaces existing devices, which are actuated by natural gas, with devices that are actuated with compressed air. This requires the addition of electric-powered air compressors at natural gas facilities but can result in zero CH_4 emissions from pneumatics. A barrier to implementation of compressed-air pneumatics is electricity availability. The United States has an extensive electricity grid, but grid connections are not always near production sites. The same report notes that proven technologies exist for reducing CH_4 emissions from compression systems (as described below):

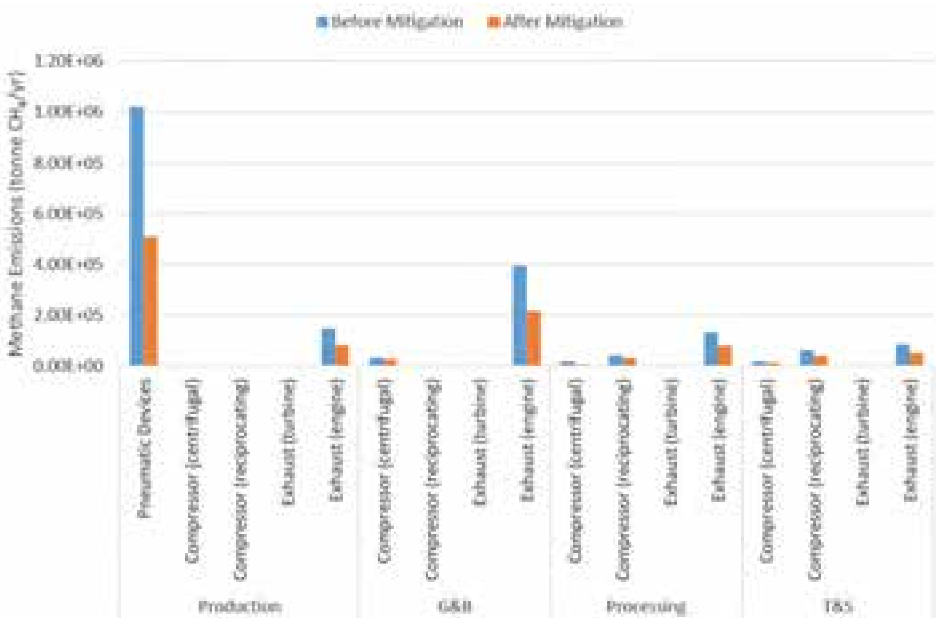
- Centrifugal compressors emissions can be reduced by replacing wet seals with dry seals. These seals are used around the rotating shaft of the compressor and prevent high pressure gas from escaping the compressor. Wet seals involve the use of recirculating oil that emits 40–200 standard cubic feet (scf) of natural gas per minute (min). Dry seals use gas to seal the compressor shaft and emit only 6 scf/min. The replacement of wet seals with dry seals reduces centrifugal compressor emissions by 85–97 percent.

- Reciprocating compressor emissions can be reduced by replacement of rod packing. Packing prevents gas from moving around piston rods and escaping the compression cylinder. New packing that is properly installed on a well-maintained compressor will emit about 12 scf/hour. The emission rate for old or poorly installed packing can range 25–67 scf/hour. When compared to the emission rate for new packing, this equates to potential emission reductions of 52–82 percent. Rod packing replacement is a mature technology, but there are new technologies that can also reduce reciprocating engine exhaust slip. These new technologies include advanced materials that increase piston rod service life while reducing rod wear and Teflon-coated rings that reduce friction while maintaining a tight seal. There are no data currently available, however, on the emission reduction potential tied to deploying these new technologies.

- The majority of the CH_4 emissions from reciprocating compressors are due to the CH_4 slip from engine exhaust. Comparing the exhaust emission factors for rich burn and lean burn engines,[b] respectively, shows that rich burn engines have a combustion effectiveness of 97 percent and lean burn engines have combustion effectiveness of 99 percent. Air-fuel-ratio controls are an option for improving the combustion effectiveness of lean burn engines while keeping NOx emissions low. More research is required to understand the limits of air-fuel-ratio controls but, for this analysis, it is assumed that they can increase the combustion effectiveness of a lean burn engine by 97–99 percent.

Exhibit 2-12 illustrates the impact of these mitigation approaches (Littlefield et. al 2020).

Exhibit 2-12. Illustration of mitigation measure impact for pneumatic devices and compressors



Balcombe et al. (2018) note that pre-emptive maintenance and a faster response to detection of high emissions are methods for reducing the impact of super emitters. Identifying a cost-effective solution is imperative and much attention is being given to developing lower cost emission monitoring and detection equipment. As Brandt et al. (2016) point out, identifying larger leaks from the highest emitters may be carried out using less sensitive, and consequently cheaper, detectors in areas at the highest risk.

[b] The terms rich-burn and lean-burn simply refer to the way in which the engine burns fuel—the air-to-fuel ratio. A rich-burn engine is characterized by excess fuel in the combustion chamber during combustion; and a lean-burn engine is characterized by excess air in the combustion chamber during combustion.

Alvarez et al. (2018) note that key aspects of effective mitigation include pairing well-established technologies and best practices for routine emission sources with economically viable systems to rapidly detect the root causes of high emissions arising from abnormal conditions. The latter could involve combinations of current technologies, such as on-site leak surveys by company personnel using optical gas imaging, deployment of passive sensors at individual facilities or mounted on ground-based work trucks, and in situ remote-sensing approaches using tower networks, aircraft, or satellites. Over time, the development of less failure-prone systems would be expected through repeated observation of and further research into common causes of abnormal emissions, followed by reengineered design of individual components and processes.

With respect to liquefaction, Mokhatab (2014) note that most of the plant energy consumption and resultant emissions in natural gas liquefaction facilities occur in the compressor drivers, where fuel energy (usually natural gas) is converted to mechanical work (or electricity in case of electrically driven compressors). Due to the energy consumption scale of the LNG plants, any enhancement to the energy efficiency of a plant will result in a significant reduction in gas consumption and consequently CO_2 emissions (Mokhatab, 2014).

There are two ways to increase the energy efficiency of LNG plants: 1) liquefaction cycle enhancement and 2) driver cycle enhancement. Liquefaction cycle enhancements reduce compressor power and consequently the compressor driver's fuel consumption. Driver cycle enhancement reduces the amount of fuel consumption to generate a specific amount of power. Typical fuel sources for natural gas liquefaction cycles include either pure refrigerant in cascade cycles, expansion-based cycles, or mixed refrigerant cycles.

Pure refrigerant cycles have a constant evaporating temperature that is a function of the saturation pressure. Mixed refrigerant cycles do not maintain a constant evaporating temperature at a given pressure. Their evaporating temperature can range and change depending on the pressure and composition. A refrigerant mixture of hydrocarbons and nitrogen is chosen so that it has an evaporation curve that matches the cooling curve of the natural gas with the minimum temperature difference. Therefore, small temperature differences reduce entropy generation and, thus, improve thermodynamic efficiency, reduce power consumption, and reduce the emissions associated with liquefaction facilities (Mokhatab 2014).

A study from Pospíšil et al. (2019) notes that a certain part of the energy spent on liquefaction can be recovered by the utilization of the cold stream from LNG. The amount of usable cold is given by thermophysical properties of natural gas and corresponds to 830 kilojoule (kJ)/kg of LNG. This cold energy can be recovered during the regasification process.[c] Regasification is carried out either in port terminals before natural gas is transported via gas lines or directly before the use of natural gas. The exploitation of cold from LNG is quite limited at present. Most of the available cold is wasted during the regasification process when LNG is heated up by

[c] LNG is kept in liquid form through maintaining a storage and transport temperature of approximately -160 °C. When LNG is regasified, there are hot and cold "streams" in the process. Through heat-integration (through heat exchangers, for example), one can utilize a hot or cold stream of a thermochemical process to supply or remove heat from another part of the process.

water or ambient air. Inefficient use of cold temperature streams reduces the overall efficiency of this primary energy source and leads to greater emissions. Pospíšil et al. (2019) recommends that promising ways of utilizing cold from LNG in the regasification process should be explored and implemented (Pospíšil et al., 2019).[l] For LNG that is ultimately combusted for electricity, Jordaan et al. (2022) find that deploying mitigation options can reduce global aggregate GHG emissions from gas-fired power by 71 percent with carbon capture and storage (CCS), CH_4 abatement, and efficiency upgrades contributing 43 percent, 12 percent, and 5 percent, respectively—and this suggested mitigation falls within country borders, except with respect to an annual accumulation of 20.5 $MtCO_2e$ of ocean transport emissions generated.

Roman-White et al. (2021) note that for LNG, harmonized data collection and reporting would build confidence in supplier claims about LCA emissions, enabling comparisons between natural gas supply chains and supporting climate goals for all participants in the supply chain. This could stimulate a virtuous cycle of demand for GHG accounting and reduction and provision of more granular, company-specific emissions estimates.

MacKinnon et al. (2018) demonstrate that natural gas-fired power generation and the natural gas system could play several important roles in supporting sustainable energy strategies over time that can achieve societal GHG reduction goals and help the transition to renewable sources. Natural gas generation can support transitions to renewable resources 1) by use in advanced conversion devices to provide complementary grid services efficiently and with very low emissions to maximize the benefits of intermittent renewable resources (e.g., running a natural gas compression system during peak renewables production), and 2) natural gas generation and the existing natural gas infrastructure can support the use of renewable natural gas with high energy and environmental benefits.

According to Stern (2022), three major requirements for creating credible measuring, reporting, and verification of CH_4 emissions are 1) to move measurement and reporting of CH_4 emissions from standard factors—either engineering-based or from EPA data—to empirical (Tier 3) measurements, and to reconcile bottoms-up (ground level) and top-down (satellite/aircraft/drone) observations; 2) to ensure that data measurement and reporting has been verified and certified by accredited bodies; and 3) to require asset-level emissions data to be transparent and publicly available. Failure to do so on grounds of commercial confidentiality risks being interpreted as evidence that the data is not credible.

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3 AIR QUALITY

The natural gas supply chain contributes to the pollution of air quality in several ways, including 1) the leaking, venting, and combustion of natural gas during exploration and production; and 2) the combustion of natural gas and other fossil fuel resources or other emissions during associated operations (e.g., extraction, transportation, downstream combustion). Emissions sources include pad, road, and pipeline construction; well drilling, completion, and flowback activities; and natural gas processing and transmission equipment such as controllers, compressors, dehydrators, pipes, and storage vessels. Pollutants include, most prominently, CH_4 and volatile organic compounds (VOCs)—of which the natural gas industry is one of the highest-emitting industrial sectors in the United States—in addition to nitrogen oxides (NOx), sulfur dioxide (SO_2), and various forms of other hazardous air pollutants (HAPs) (Congressional Research Service [CRS], 2020). Pollutants are described in detail below (CRS, 2020):

- CH_4 is the principal component of natural gas and is a precursor to ground-level ozone formation (i.e., “smog”).
- NOx is a ground-level ozone precursor.[d] Significant amounts of NOx are emitted during the combustion of natural gas and other fossil fuels (e.g., diesel). The combustion of natural gas occurs when it is flared during drilling and well completions and when used to drive the various compressors that move products through the system. Combustion also occurs in engines, drills, heaters, boilers, and other production equipment.
- VOCs are a ground-level ozone precursor. The crude oil and natural gas sector is currently one of the largest sources of VOC emissions in the United States, accounting for approximately 20 percent of man-made VOC emissions nationwide (and representing almost 40 percent of VOC emissions released by stationary sources). VOCs—in the form of various hydrocarbons—are emitted throughout a wide range of natural gas operations and equipment. The interaction among VOCs, NOx, and sunlight in the atmosphere contributes to the formation of ozone.
- SO_2 is emitted from crude oil and natural gas production and processing operations that handle and treat sulfur-rich, or “sour,” gas.
- HAPs, also known as air toxins, are those pollutants that are known or suspected to cause cancer or contribute to other serious health effects including reproductive issues and birth defects. Of the HAPs emitted from natural gas systems, VOCs are the largest group and typically evaporate easily into the air. The most common HAPs produced from natural gas systems are n-hexane and benzene, toluene, ethylbenzene, and xylenes (BTEX) compounds. Some natural gas reservoirs may also contain high levels of hydrogen sulfide (H_2S). HAPs are found primarily in natural gas itself and are emitted from equipment leaks and during processing, compressing, transmission, distribution, or storage operations. HAPs are also a byproduct of incomplete fuel combustion and may be components in various chemical additives.

[d] NOx is the collective term for the nitrogen oxides NO and NO_2.

NETL (2019) analyzed the N_2O emissions at each stage of the natural gas supply chain. The analysis found a total of 0.14116 milligrams (mg) of N_2O were emitted per MJ of natural gas delivered (Exhibit 3-1). The largest contributor (86 percent) to this total number was N_2O emissions that occur during the transmission stage.

Exhibit 3-1. N_2O emissions across the natural gas supply chain

Stage of Natural Gas Supply Chain	N_2O Emissions (mg/MJ)
Production	0.0155
G&B	0.0000
Processing	0.0047
Transmission	0.1210
Storage	0.0000
Pipeline	0.0000
Distribution	0.0000
Total	*0.14116*

Commented [HSAJ5]: Comment for FECM - I find that scientific notation can sometimes be confusing to a non-engineering audience. As such, I have scaled the numbers accordingly to a unit that allows reasonable presentation of these N2O emissions without the use of scientific notation. The result of this was the use of units mg N2O per MJ of delivered natural gas. The original units used in the 2019 NETL LCA spreadsheet were kg N2O per MJ of delivered natural gas.

3.1 Upstream Production and Hydraulic Fracturing

The venting of natural gas during extraction and processing is a key source of VOC emissions. Similar to CH_4, VOCs are a naturally occurring constituent of natural gas and can react with other pollutants to produce ground-level ozone. Another source of VOC emissions during upstream operations is venting from condensate storage tanks, which occurs in regions with wet gas.[e]

The combustion of natural gas in compressors and gas processing equipment produces NOx and carbon monoxide (CO). Similarly, the combustion of diesel in drilling equipment produces NOx and CO, as well as significant quantities of SO_2 emissions. Beyond VOCs, CH_4, NOx, CO, and SO_2 emissions, upstream processes can also produce aliphatic hydrocarbons, (e.g., C2–C5), alkanes, VOCs (e.g., BTEX), H_2S, n-hexane, and formaldehyde, which can contaminate ambient air (Wollin et al., 2020).

Elliott et al. (2017) estimates that up to 143 air contaminants can be released during hydraulic fracturing. The International Agency for Research on Cancer generates hazard assessments for only 20 percent of these identified contaminants. Twenty of these air contaminants are known carcinogens. Other air contaminants are generated by the peripheral plant components. These include particulate matter, NOx, precursors of ozone and polycyclic aromatic hydrocarbons (Wollin et al., 2020).

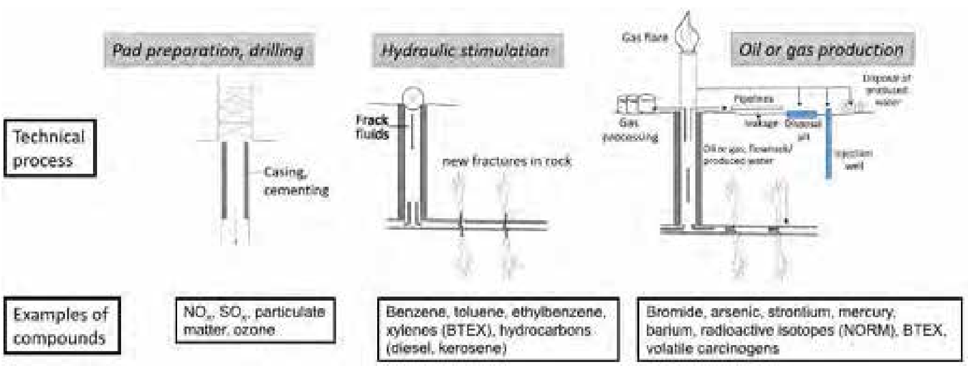
The following activities are known to contribute to air contamination at oil or gas drilling sites:

[e] When natural gas is retrieved, it can be considered wet or dry. Dry natural gas is at least 85 percent methane, but often more. Wet natural gas contains some methane, but also contains liquids such as ethane, propane, or butane. The more methane natural gas contains, the "dryer" it is considered.

- Preparation of the drilling site including road connections
- Drilling of the well
- Truck traffic for delivery and disposal of materials
- Removal of acid gases and water from gas; separation of natural gas from other hydrocarbons
- Operation of compressor stations to enable the transport of natural gas into transport pipelines
- Preprocessing of crude oil prior to refinery

Exhibit 3-2 illustrates the supply chain for natural gas where each of these activities occurs (Wollin, 2020).

Exhibit 3-2. Illustration of supply chain steps where upstream air pollution occurs



Used with permission from Wollin et al. (2020)

NOx and SOx emissions have been reported to be higher during the development of the drilling site compared to during the production phase (Wollin et al., 2020). Similar observations have been made for particulate matter (PM) (e.g., PM2.5 and PM10). Analysis of shale gas production sites in North Texas showed an 8 percent increase in ozone concentrations at natural gas production sites compared to control sites (Wollin et al., 2020).

Indirect energy consumption can also affect the air quality profile of gas extraction technologies. If the development or operation of a natural gas well uses grid electricity, then the fuel mix of the electricity grid will affect the life cycle performance of the well. The indirect air quality impacts of electricity consumption depend on the fuel mixes and combustion characteristics of power plants that compose a regional electricity grid. Exhibit 3-3 offers a perspective on non-GHG air pollutant by supply chain step or equipment.

Exhibit 3-3. Perspective of non-GHG air pollutant by supply chain step or equipment

Source	Air pollutant				Data quality
	NO_X	VOC	PM	Other toxic substances	
Well development					
Drilling rigs	•	◦	•	•	Medium
Frac pumps	•	◦	•	•	Medium
Truck traffic	•	◦	•	•	Medium
Completion venting		•		•	Poor
Frac ponds		◦			Poor
Gas production					
Compressor stations	•	•	◦	•	Medium
Wellhead compressors	◦	◦	◦	◦	Medium
Heaters, dehydrators		◦	◦	◦	Medium
Blowdown venting		◦		◦	Poor
Condensate tanks		•		◦	Poor
Fugitives				◦	Poor
Pneumatics		◦		◦	Poor

• Major source, ◦ minor source

Used with permission from Wollin et al. (2020)

McMullin et al. (2018) analyzed exposure to VOCs emitted during hydraulic fracturing in Colorado. They identified 56 different VOCs that were emitted during hydraulic fracturing using data compiled from 47 existing air monitoring devices that measured these VOCs at 34 different locations across the region.

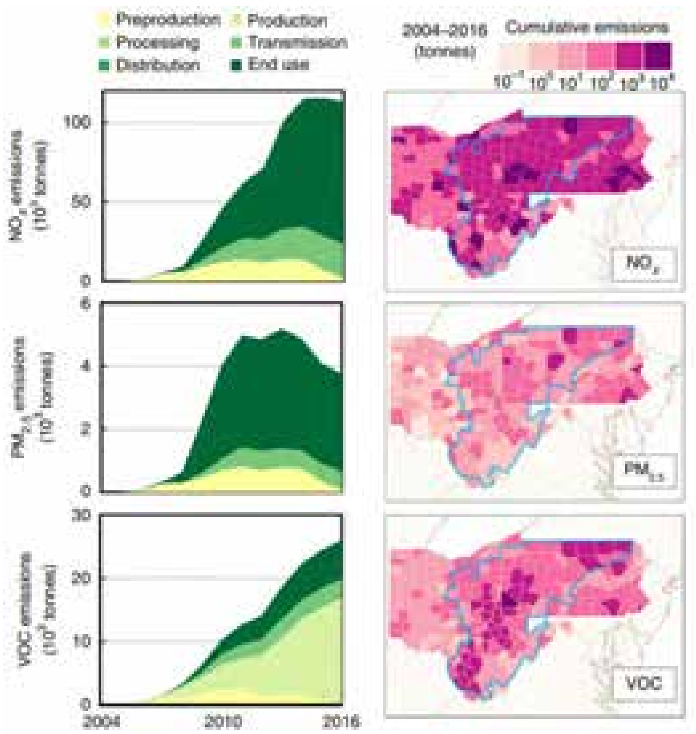
Plant et al. (2022) used airborne sampling to measure flare efficiency[f] in three major gas production regions in the United States. They found that both unlit flares and inefficient combustion contribute comparatively to ineffective CH_4 destruction, with flares effectively destroying only 91.1 percent (90.2–91.8 percent; 95 percent confidence interval) of CH_4 emissions. Other emissions from flaring can include carbon particles (soot), unburned hydrocarbons, CO, partially burned and altered hydrocarbons, NOx, and (if sulfur containing material such as H_2S or mercaptans is flared) SO_2. The combustion products of flaring at natural gas production and processing sites specifically include CO_2, CH_4, and N_2O.

Mayfield et al. (2019) performed an analysis of the environment impacts associated with the shale gas boom in the Appalachian Basin and found the majority (61 percent) of VOC emissions

[f] The flare efficiency is a measure of the effectiveness of the combustion process to fully oxidize the fuel. When inefficiencies occur, unburned fuel, CO, and other products of incomplete combustion (e.g., soot, VOCs, etc.) are emitted into the atmosphere.

from the natural gas supply chain can be largely attributed to upstream processes and are spatially concentrated in counties with the highest cumulative production. Upstream processes contribute the most to total NOx (67 percent) and PM2.5 (73 percent) emissions across the natural gas supply chain; NOx and PM2.5 emissions are relatively evenly distributed across counties (Mayfield et al., 2019). Exhibit 3-4 presents annual NOx, PM2.5, and VOC emissions from the natural gas supply chain within Pennsylvania, Ohio, and West Virginia, along with the spatial distribution of cumulative NOx, PM2.5, and VOC emissions by county between 2004 and 2016. It is important to note that the blue lines delineate shale gas-producing counties (Mayfield et al., 2019).

Exhibit 3-4. Annual (left graphs) and cumulative (right graphs) (2004–2016) NOx, PM2.5, and VOC emissions from natural gas supply chain within Pennsylvania, Ohio, and West Virginia



Permission pending from Mayfield et al. (2019)

3.2 MIDSTREAM TRANSPORT EMISSIONS

CH_4 leakage in the transmission and distribution systems was documented in Section 2. This mid-stream segment leakage has important air pollutant considerations, since CH_4 can be a precursor to ground-level ozone formation.

While the presence of HAPs in unprocessed, upstream natural gas has been documented, little has been published on their presence in the midstream segments of the natural gas supply chain. Nordgaard et al. (2022) systematically evaluated publicly available, industry-disclosed HAP composition data from natural gas infrastructure applications submitted to FERC between 2017 and 2020. These applications covered 45 percent of the U.S. onshore natural gas transmission system (as measured by pipeline miles). Given that reporting HAP composition data is not required by FERC, only 49 percent of approved projects disclosed their HAP composition data to FERC. Of the applications that did disclose their HAP composition data, HAP concentrations were typically reported as higher for separator flash gas and condensate tank vapor, compared to LNG and transmission-grade natural gas, with mean benzene concentrations of 1106, 7050, 77, and 37 parts per million, respectively.

Nordgaard et al. (2022) also identified one pipeline operator that reports real-time HAP concentrations for natural gas at five pipeline interconnection points. Similar to the FERC applications, this operator reported BTEX and H_2S as present in the pipelines used to transport their natural gas. Because current transmission infrastructure releases natural gas during uncontrolled leaks, loss of containment events, and routine operations (e.g., blowouts and compressor station blowdowns), having access to HAP composition data may be important for conducting both air quality and health-focused evaluations of natural gas releases.

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4 WATER USE AND QUALITY

The literature describes the treatment and management of wastewaters as a central environmental concern regarding natural gas production. Especially in the eastern regions of the United States where—although water resources are abundant—significant natural gas production has been occurring. In the western parts of the United States, persistent dry climates limit the use and availability of freshwater for natural gas production—specifically, freshwater availability for drilling and hydraulic fracturing.

Gallegos et al. (2015) estimate that drilling and hydraulically fracturing a shale gas well can consume between 2.6–9.7 MM gallons (gal) of water. From 2014 to 2015, unconventional shale gas in the United States used 187 billion (B) gal of water. From 2012 to 2014, the average use of water for hydraulic fracturing was 30.6 B gal annually. Additionally, Gallegos et al.'s (2015) integrated data from 6–10 years of operations suggests 212 B gal of produced water[g] are generated from unconventional shale gas and oil formations.

While extensive growth in hydraulic fracturing has increased water use for natural gas production across the United States, the water use and produced water intensity of these well stimulation activities is lower than the water use and produced water intensity of other energy extraction methods and represents only a small fraction of total industrial water use nationwide (Kondash and Vengosh, 2015). However, given the amount of water required for natural gas production, even the smallest local or seasonal water supply shortages can cause issues.

Water quality can also be impacted by natural gas production processes if water is inadequately managed or by the use of fracturing chemicals both on the surface—before injection and after flowback—and in produced water. Subsurface water quality impacts can result from the migration of fracturing fluids, formation waters, and CH_4 along well bores and through rock fracture networks. Management and disposal efforts increasingly include efforts to minimize water use through recycling and re-use of fracturing fluids, in addition to treatment and disposal of wastewater through deep underground injection.

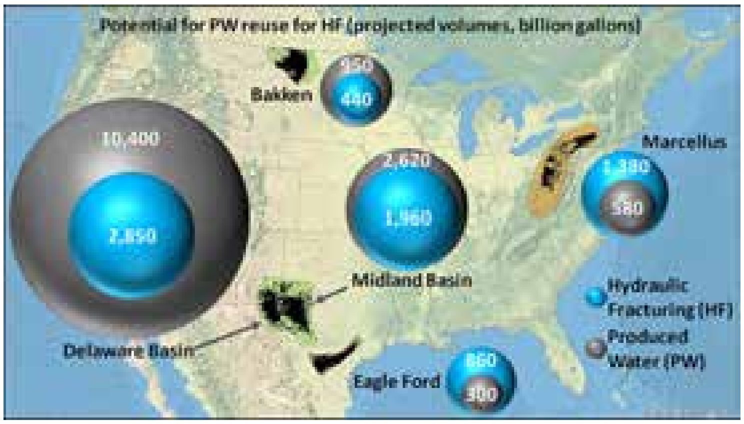
The shale boom has made energy more available and affordable globally but has also contributed to environmental concerns surrounding the use of water. Scanlon et al. (2020a) analyze the water-related sustainability of energy extraction. They focus on meeting the rapidly rising water demand for hydraulic fracturing and managing growing volumes of water co-produced with oil and gas. They also analyze historical (2009–2017) volumes of water in ~73,000 wells and project future volumes of water use in major U.S. unconventional oil and gas plays. Their results show a marked increase in water use for fracking, depleting groundwater resources in some semiarid regions (Scanlon et al., 2020a).

Water issues related to both fracking water demand and produced water supplies may be partially mitigated through the reuse of produced water to frack new wells. As shown in Exhibit

[g] Produced water is defined as the water that is withdrawn through oil and gas extraction. Produced water can begin as ground water within the hydrocarbon barring formations, however as the extraction matures or in the case of shale or tight formations where hydraulic fracturing is necessary to liberate the hydrocarbon, produced water can also contain fluids that were previously injected.

4-1, projected produced water volumes exceed fracking water demand in semiarid Bakken (2.1×), Permian Midland (1.3×), and Delaware (3.7×) oil plays, with the Delaware oil play accounting for ∼50 percent of the projected U.S. oil production (Scanlon et al., 2020a). Therefore, water issues could constrain future energy production, particularly in semiarid oil plays.

Exhibit 4-1. Map showing ratio between produced water and fracking water demand for major shale basins



Used with permission from Scanlon et al. (2020a)

4.1 Water Use for Unconventional Natural Gas Production

Most of the water used for unconventional natural gas production is used for drilling for hydraulic fracturing. For example, of the total water used by the shale gas industry, hydraulic fracturing is estimated to account for about 89 percent, drilling about 10 percent, and infrastructure the remainder (1 percent) (Hayes and Severin, 2012). Water is also the main component of the fluids used for hydraulic fracturing, making up approximately 99 percent of the total volume.

Reporting from Gallegos, et al. (2015) suggests hydraulic fracturing uses 2.6–9.7 MM gal of water per well drilled, while the American Petroleum Institute (API) (API 2023) suggests the average hydraulically fractured well uses 4 MM gal of water. As water is a scarce resource, it is important to consider the potential environmental impacts of using water from different sources (e.g., ground water, surface water). If available surface water is used to support natural gas production, then the ecosystems that rely on this water could be harmed. Significant groundwater withdrawals can also permanently deplete aquifers.

The process of hydraulic fracturing uses large volumes of water mixed with chemicals and proppant (sand) to fracture low-permeability shale and tight oil rocks, allowing the extraction of hydrocarbons. Despite the higher water intensity (the amount of water used to produce a unit of energy; for example, liters per gigajoule) compared to drilling conventional vertical oil and gas wells, overall water withdrawals for hydraulic fracturing is negligible compared to other industrial water uses on a national level (Vengosh et al., 2014; Jackson et al., 2014; Kondash, Albright, and Vengosh, 2017; Kondash and Vengosh, 2015). On a local level, however, water use for hydraulic fracturing can cause conflicts over water availability, especially in arid regions such as the western and southwestern United States where water supplies are already limited (Scanlon, Reedy, and Nicot, 2014; Ikonnikova et al. 2017; Nicot and Scanlon, 2012; Ikonnikov et al., 2017; Kondash, Lauer, and Vengosh, 2018).

4.1.1 Water Consumption Impacts

Water use for hydraulic fracturing and wastewater production in major shale gas and oil producing regions increased between 2011 and 2016, with water use per well increasing by up to 770 percent—with flowback and produced water volumes generated within the first year of production increasing up to 550 percent. Water-use intensity (that is, normalized to energy production) increased in all U.S. shale basins, except the Marcellus shale basin, over this period (Kondash, Lauer, and Vengosh, 2018).

Water consumption per shale gas well can vary due to four conditions:

- **Geology:** maturity of the shale and formation depth, thickness, and lateral extent
- **Technology:** horizontal or vertical drilling, water recycling
- **Operations:** operator decisions, availability of nearby freshwater
- **Regulatory:** requirements for use and treatment of water

During 2009–2017, ~73,000 wells, or an aggregated total lateral length of ~440 × 10^6 ft (134,000 km) equivalent to ~3× the Earth's circumference (40,000 km) was drilled in eight plays studied by (Dieter et al. 2018). Dieter et al. (2018) found that to fracture the rock along that length ~480 B gal of water are required, equivalent to ~0.1 percent of the U.S. 2015 total water withdrawal, or almost two days of freshwater withdrawal (280 B gal/day).

Exhibit 4-2 shows the water consumption for hydraulic fracturing, the amount of produced water used and oil and gas outputs from 9 major plays in the United States from 2009 – 2017 (Scanlon et al., 2020a). The Eagle Ford play has used 173 B gal of combined hydraulic fracturing and produced water, at nearly a 1.83 ratio of freshwater to produced water and the Marcellus has a freshwater to produced water ratio of 5.83. Other plays use more produced water than freshwater, like Bakken, Delaware, and Barnett, where the ratios of produced water to freshwater are 1.83, 2.21, and 2.11 respectively.

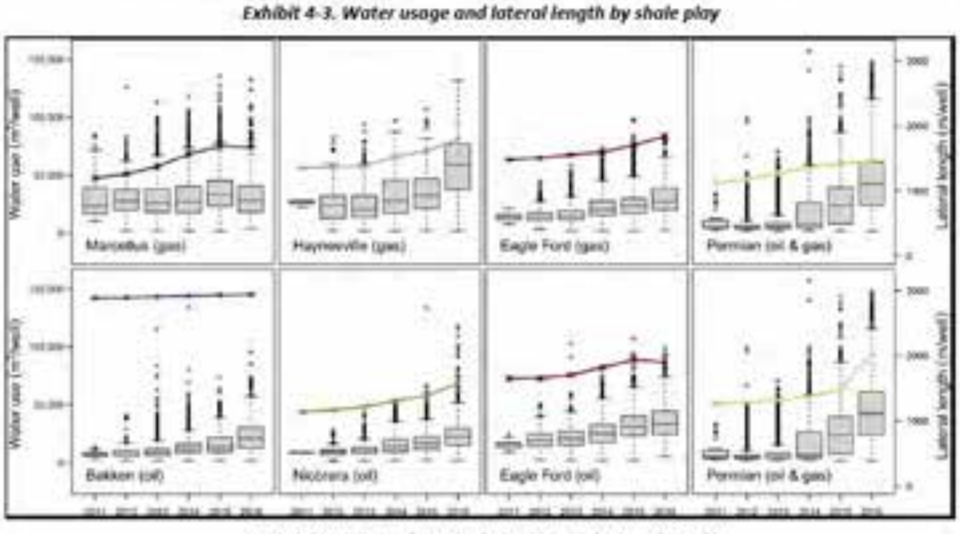
Exhibit 4-2. water use in nine shale plays in the U.S.

Play	Total Length (10^6 ft)	Median Well Length (ft)	Number of Wells	Hydraulic Fracturing Water (10^9 gal)	Produced Water (10^9 gal)	Oil (10^9 gal)	Gas (10^9 gal of oil equivalent)
Bakken	114	9,580	12,036	49	75	100	22
Eagle Ford	95	6,061	17,366	112	61	103	78
Midland	49	8,575	6,461	79	44	30	14

Play	Total Length (10^6 ft)	Median Well Length (ft)	Number of Wells	Hydraulic Fracturing Water (10^9 gal)	Produced Water (10^9 gal)	Oil (10^9 gal)	Gas (10^9 gal of oil equivalent)
Delaware	36	5,272	7,070	51	113	40	26
Marcellus	51	7,139	9,651	70	12	3	214
Niobrara	21	7,438	3,842	21	5	14	11
Barnett	27	5,241	7,453	35	74	1	111
Haynesville	15	6,270	3,215	30	16	0.03	107
Fayetteville	21	6,386	4,717	24	-	-	55

Exhibit 4-3 from Kondash, Lauer, and Vengosh (2018) indicates that, parallel to the increase in lateral lengths of the horizontal wells and hydrocarbon extraction yields through time, water use has also increased. The relative increase in lateral length (4–60 percent) was, however, significantly lower than the increase in water use (14–770 percent). When water use per well was normalized to the length of lateral section of the horizontal well, in almost every case among oil producing regions, an increase in water use per length of the horizontal well is observed. This pattern was most evident in the Permian region, where water use increased from 4.4 cubic meters (m^3) per meter in 2011 to 29.3 m^3 per meter in 2016 for gas-producing wells, and from 3.9 m^3 per meter in 2011 to 21.1 m^3 per meter in oil-producing wells. In all cases, with the exception of the Marcellus shale play in 2016, the flowback and produced (FP) water generation also increased through time, with particularly higher rates after 2014.

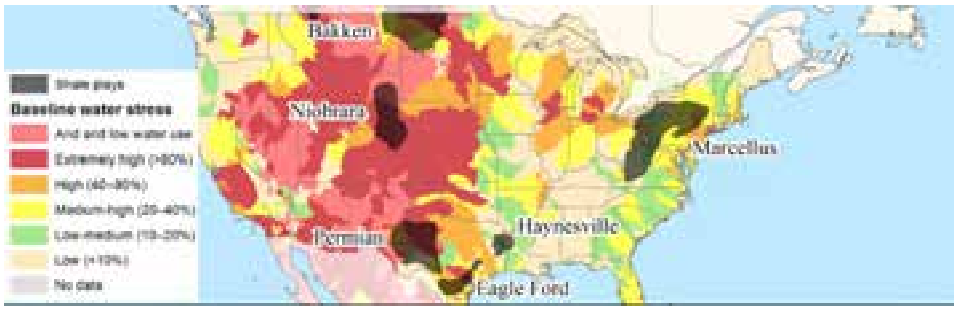
Exhibit 4-3. Water usage and lateral length by shale play



Used with permission from Kondash, Lauer, and Vengosh (2018)

Kondash et al. (2018) also illustrates water conditions where the major plays across the United States are located, see Exhibit 4-4. The Bakken, Niobara, Permian and Eagle Ford plays are all located in arid to extremely dry climates where drought conditions have persisted for many years.

Exhibit 4-4. Baseline water stress and location of shale plays



Used with permission from Kondash, Lauer, and Vengosh (2018)

4.1.2 Water Quality

Concerns have been raised about potential public health effects that may arise if hydraulic fracturing-related chemicals were to impact drinking water supplies. The chronic oral toxicity values—specifically, chronic oral reference values (RfVs) for noncancer effects, and oral slope factors (OSFs) for cancer are available for the list of 1,173 chemicals EPA identified as "associated with hydraulic fracturing." These include 1,076 chemicals used in hydraulic fracturing fluids and 134 chemicals detected in the flowback or produced waters from hydraulically fractured wells.

EPA compiled RfVs and OSFs for these chemicals using six different governmental and intergovernmental data sources. Ninety (8 percent) of the 1,076 chemicals used in hydraulic fracturing fluids and 83 (62 percent) of the 134 chemicals found in flowback/produced water had a chronic oral RfV or OSF reported in at least one or more of the six data sources used. Thirty-six of the chemicals used in hydraulic fracturing fluids have been measured in at least 10 percent of the hydraulically fracted wells drilled nationwide (identified from EPA's analysis of the FracFocus Chemical Disclosure Registry 1.0). Eight of these 36 chemicals (22 percent) had an available chronic oral RfV. The lack of chronic oral RfVs and OSFs for the majority of these chemicals highlights the significant knowledge gap that exists to assess the potential human health hazards associated with hydraulic fracturing (Yost et al., 2016).

Ecological risks to surface waters are present throughout the well life cycle and may manifest themselves differently locally compared to regionally. These risks can also vary temporally, as development activity like surface water withdrawal may only result in a single, brief impact, while the network of roads required for accessing well pads could increase erosion and sediment runoff for years. Previous work identified the primary risks to surface water quality as sediment runoff from devegetation, leakage and spillage of chemicals into surface waters, unsustainable water withdrawal, landscape fragmentation, and insufficient treatment of oil and gas wastewater prior to discharge (Krupnick, Gordon, and Olmstead, 2013; Slonecker et al., 2012; Drohan et al., 2012; Kiviat, 2013). Unfortunately, few sites exist where baseline environmental monitoring occurred prior to hydraulic fracturing operations commencing, greatly complicating efforts to precisely quantify the impacts of hydraulic fracturing, particularly if these operations are occurring in watersheds with preexisting anthropogenic influence and a host of existing ecological stressors (Mauter et al., 2014; McBroom, Thomas, and Zhang, 2012).

The surface water risks and impacts associated with unconventional resource development vary significantly by region (Clements, Hickey, Kidd, 2012). To date, those in the Marcellus region have been examined most extensively. This scrutiny has been motivated by the nexus of regionally specific risk drivers, such as high gradient terrains that could lead to increased erosion, an abundance of small streams, highly variable in-stream flow rates, and the high salinity of produced water in the Marcellus. Moreover, during the early development of the Marcellus shale in Pennsylvania, the state permitted the disposal of hydraulic fracturing brines in municipal wastewater treatment plants. The most recent studies suggest to reduce the human and environmental impacts associated with this original practice the State of Pennsylvania asked companies to adopt a moratorium on the disposal of produced water in wastewater treatment plants in the state (Wilson and Van Briesen, 2012; Wilson, Wang, and Van Briesen, 2013; Warner et al., 2013a; Wilson and Van Briesen, 2013; Renner, 2009 Abdalla et al., 2016).

The rapid development of unconventional gas extraction has increased the flux of both solid and liquid waste, fluxes proportionally much greater than those generated from traditional conventional well development on a per well basis. Drill cutting wastes from unconventional wells may contain more total naturally occurring radioactive materials (NORM) than conventional wells for two reasons. Geochemically, the shale itself contains more naturally occurring radioactive materials (NORM) than sandstone and limestone reservoirs holding conventional reserves (Badertscher et al., 2023; Huang et al., 2017). Physically, the horizontal bore is usually much longer than the vertical bore and a larger proportion of the drill cuttings are composed of the NORM rich shale due to the directional drilling. The Pennsylvania Department of Environmental Protection (PADEP) reported drill cuttings with the following ranges: ^{226}Ra (below detection limit to 640 becquerels/kg) and ^{228}Ra (0.37–104 becquerels/kg) (PADEP, 2016).

Higher NORM values in solids and liquids resulted in higher downstream values of ^{226}Ra and ^{228}Ra as well. Stream water and sediments in areas bracketing outfalls of facilities treating waste from landfills accepting O&G waste indicate accumulation of NORM in the sediments. Given distance from the outfall, these accumulations are of similar magnitude to those downstream of brine treatment facilities reported in the literature (Warner et al., 2013b) and indicate additions from a low ^{228}Ra/^{226}Ra activity ratio source, consistent with Marcellus formation sources (Lauer Warner, and Vengosh, 2018).

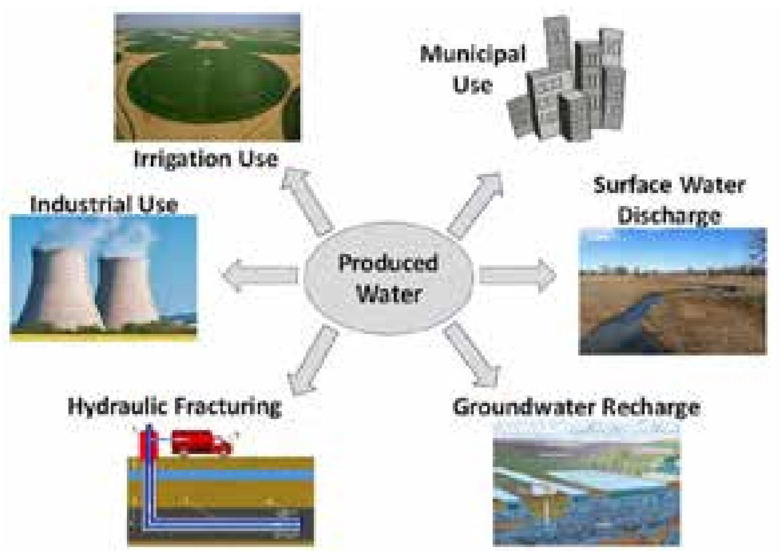
4.1.3 General Guidelines for Leading Best Practices on Water Remediation

Increasing demand for water for drilling and hydraulic fracturing in shale gas plays has driven operators to seek supplemental sources of water and alternatives to local freshwater supplies. Potential alternatives include industrial wastewater, water treatment plant outflows, abandoned mine waters, saline groundwater, and reuse of produced waters.

The Groundwater Protection Council's (GWPC) 2023 report (2023) summarizes the most notable changes in produced water operational and management practices in each major production region. The regions include both oil and gas production, with the Permian basin being the largest produced water region, producing 10.5 times more than the Bakken, 16.4 times more than the Eagle Ford and 49 times more than the Appalachian region.

With many of these plays being in areas where water scarcity is an issue, reducing water consumption is critical. Therefore, produced water reuse technologies are critical. Treated produced water reuse outlets allow reuse options. Once PW is treated to fresh water or discharge standards it can be reused. Exhibit 4-5 shows the major reuse outlets for treated produced water (Scanlon et al., 2020b).

Exhibit 4-5. Major produced water reuse outlets



Used with permission from Scanlon et al. (2020b)

When it comes to the beneficial reuse of produced water in any of the major development basins, the primary challenge to overcome is the desalination of the water by way of treatment and managing the associated products and wastes that are generated. Aside from the regulatory and liability challenges associated with the discharge of produced water, this simple answer does provide a comprehensive perspective of the technical and economic challenges associated with large-scale produced water desalination systems. All the options for reuse shown in Exhibit 4-5 require the water to meet a low salinity standard. The primary challenge faced by the beneficial reuse of PW is the removal of Total dissolved solids (TDS) or dissolved salt from the produced water matrix. Exhibit 4-6 shows the salinity ranges for different types of water (Horiba, 2016).

Exhibit 4-6. Different types of water salinity values

Salinity Status	Salinity (%)	Salinity (ppt)	Use
Fresh	<0.05	< 0.5	Drinking and all irrigation
Marginal	0.05–0.1	0.5–1.0	Most irrigation, adverse effects on ecosystems become apparent
Brackish	0.1–0.2	1–2	Irrigation for certain crops only, useful for most livestock
Saline	0.2–1.0	2–10	Useful for most livestock
Highly Saline	1.0–3.5	10–35	Very saline groundwater, limited use for certain livestock
Brine	> 3.5	> 35	Seawater, some mining and industrial uses exist

Produced water requires significant pretreatment prior to being subjected to any desalination process. The most prominent and proven water desalination technology deployed across the world is reverse osmosis which becomes increasingly inefficient when TDS concentrations exceed 35,000 ppm which is reflective of the salinity concentration in seawater. As the overwhelming amount of produced water in the U.S. is well above the levels to be treated by reverse osmosis, including the Permian (median TDS concentration – 154,000 ppm), this technology is not applicable.

When it comes to treating high salinity PW, only Thermal (Vapor) Distillation would be considered “mature and proven” for this application. These distillation technologies typically consist of a Mechanical Vapor Compression/Recompression (MVC/MVR) component and have been in use for more than a decade in the oilfield treating produced water with limited acceptance due to throughput and costs. As discussed in the original report, thermal distillation technologies often require extensive pretreatment of the water before processing including the removal of hydrocarbons, TSS, and all hardness cations.

4.2 Current Water Research and Development

The DOE drives R&D to create sustainable water management, responding to increased water demand from decarbonized power generation. Additionally, DOE seeks to provide alternative water resources in water-stressed areas by treating wastewaters from fossil energy activities and making those treated wastewaters available to end-users outside the fossil energy industry, and finally, reducing environmental impacts of fossil fuel generation during the transition to clean energy. To accomplish these goals, DOE currently has R&D focused in three areas:

1. Characterization, treatment, and management of produced waters,
2. Recovery of critical minerals - rare earths elements and other resources for beneficial reuse
3. Alternative water resources and identifying opportunities.

The Produced Water Optimization Initiative (PARETO) is an optimization framework for produced water management and beneficial use. The goal of PARETO is to develop a modeling and optimization application to identify cost-effective and environmentally sustainable produced water management, treatment, and reuse solutions.

PARETO will help with the:

- Buildout of the produced water infrastructure
- Management of produced water volumes
- Selection of effective treatment technologies
- Placement and sizing of treatment facilities
- Identification of beneficial water reuse options
- Distribution of treated produced water for reuse.

The Water Management for Power Systems program will lead the critical national R&D effort directed at removing barriers to sustainable, efficient water and energy use at fossil power plants by developing technology solutions and enhancing the understanding of the relationship between energy and water resources.

NETL will work to overcome the following challenges:

- Reduce freshwater consumption by 50%.
- Lower the cost of treating fossil power plant effluent streams by 50%.

The produced water characterization effort will focus on the critical national R&D effort directed at characterizing produced water associated with sustainable oil and gas development. The work proposed is aligned with DOE-FECM's Program goals to reduce freshwater consumption and to recover valuable resources from both effluent and alternative influent water streams. Leveraging its core capabilities, competencies, and authorities, NETL will partner with universities and industry to develop and increase to commercial readiness the technology needed to treat and manage produced water from oil and natural gas operations.

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5 INDUCED SEISMICITY

Induced seismicity is ground motion (earthquakes) caused by human activities. Earthquakes have been detected in association with both oil and natural gas production, underground injection of wastewaters (i.e., wastewater disposal), and hydraulic fracturing (Rubinstein and Mahani, 2015). Each of these processes involves injecting large volumes of foreign fluids at various pressures into underground formations.[h] Earthquakes from induced seismicity have happened in multiple countries, including the United States (Shultz et al., 2020).

5.1 IMPACTS FROM INDUCED SEISMICITY AND ENERGY TECHNOLOGIES

The term seismic activity is generally used to describe vibrations of mechanical energy that pass through the earth, much like sound waves vibrate through the atmosphere. The seismic activity of a region is defined by the frequency, kind, and magnitude of earthquakes experienced in the region during a given period. The National Earthquake Information Center (NEIC) is the entity responsible for determining, as rapidly and as accurately as possible, the location and size of all significant earthquakes that occur worldwide. At present, the NEIC locates and publishes detailed data on the 30,000 "most significant" earthquakes that occur in each year (USGS, 2023).

While millions of earthquakes occur each year, not all are felt at the surface. Earthquakes with magnitudes of 2.0 or less generally cannot be felt at the surface by people, while earthquakes with magnitudes greater than 3.0 tend to produce noticeable shaking. Earthquakes with magnitudes greater than 5.0 are felt at the surface and have the potential to cause structural damage to buildings and property. Most earthquakes that do occur are in response to natural, yet sudden slips and shifts of large masses of rock along geologic faults.

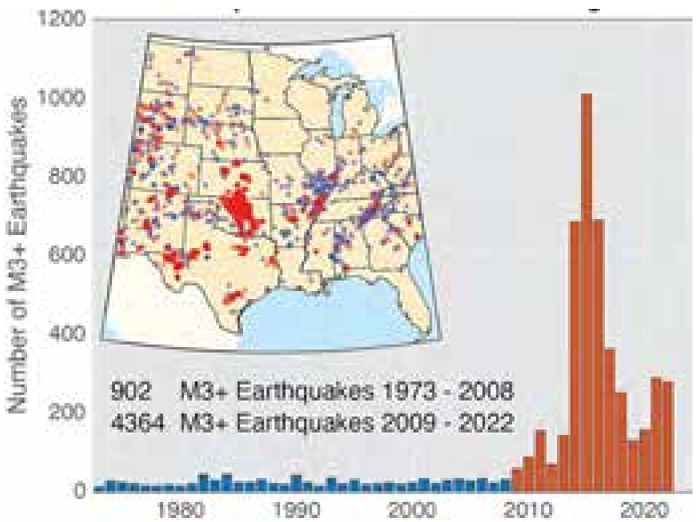
The seismicity rate in the central and eastern United States increased 40-fold within the past decade (2002–2012), predominantly as a result of human activities (Ellsworth, 2013; van der Baan and Calixto, 2017). This recent increase in seismicity rate in the central and eastern United States has largely been attributed to large-volume wastewater disposal wells injecting fluids into deep sedimentary formations (e.g., Keranen et al., 2014; Rubinstein and Mahani, 2015). Other human activities, including hydraulic fracturing (Skoumal, Brudzinski, and Currie, 2015) and carbon sequestration (e.g., Kaven et al., 2015), have induced seismicity to a lesser extent in the central and eastern United States (Skoumal et al., 2020).

Exhibit 5-1 presents the annual number of earthquakes (with a magnitude of 3.0 or larger) occurring in central and eastern areas of the United States for 1973–2022. Many of these earthquakes have taken place in areas where hydraulic fracturing has been and is actively occurring (e.g., Oklahoma) (USGS, 2022). Between 1973 and 2008, approximately 25 earthquakes of magnitude three or greater occurred on average annually. Since 2009, at least 58 earthquakes of this same size (magnitude of 3.0 or larger) have occurred annually, and at

[h] Hydraulic fracturing involves injecting large volumes of fluids into the ground to release trapped oil and natural gas. Wastewater from oil and gas production, including shale gas production, is typically disposed of by being injected at relatively low pressures into extensive formations that are specifically targeted for their porosities and permeabilities to accept large volumes of fluid.

least 100 earthquakes of this same size have occurred annually since 2013. The annual number of earthquakes (with a magnitude of 3.0 or larger) peaked in 2015 when 1,010 magnitude 3+ earthquakes were recorded. Given their magnitude, most of these earthquakes are large enough to have been felt by people, yet not large enough to cause significant damage (USGS, 2022).

Exhibit 5-1. Earthquakes in the Central and Eastern U.S. 1973–2022



Source: USGS (2022)

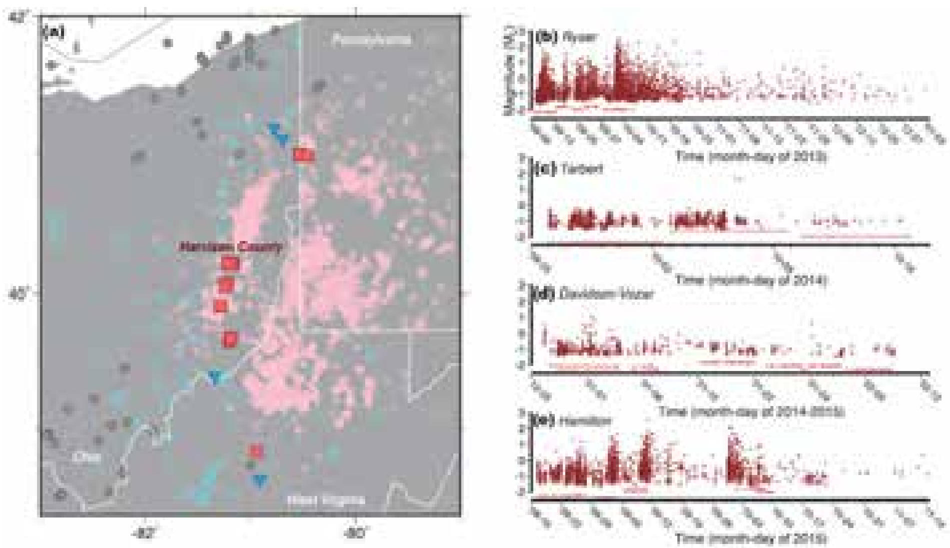
The following are examples of induced seismic events in the United States that have occurred in basins where unconventional natural gas production via hydraulic fracturing has occurred.

5.1.1 Utica and Marcellus Shales in the Appalachian Basin

The Appalachian Basin is currently the largest natural gas producing area in the United States. The basin produced over 18 Mcf of natural gas a day (500 m^3/day) in 2019 (EIA, 2019a). The Marcellus and Point Pleasant Utica shale plays are both located in the Appalachian Basin and extend from New York to Kentucky. They each cover prospective areas of 190,000 and 220,000 square kilometers (km^2), with proven reserves of 135 and 24 Tcf of natural gas, and 345- and 210-MM barrels of oil, respectively (EIA, 2019b). Earthquakes detected in the basin during 2013–2015 are presented in Exhibit 5-2.

The map on the left provides the location sequences of cataloged (magnitude > 2.0) seismic events in Ohio and neighboring states for 2010–2017. Blue triangles show earthquake sequences induced by wastewater disposal; red squares show earthquake sequences induced by hydraulic fracturing; and pink squares and blue triangles depict the horizontal and wastewater disposal wells that remain in the area. Grey circles represent earthquakes assumed to be occurring from natural causes. The four graphs on the right provide the temporal distribution of hydraulic fracturing induced seismic events for four wells in Harrison County, Ohio (Schultz, 2020).

Exhibit 5-2. Location and timing of induced and natural seismic events in the Appalachian Basin



Used with permission from Schultz et al. (2020)

5.1.2 Anadarko and Arkoma Basins of Oklahoma

Dramatic increases in seismic activity have been reported for areas in both central and northern Oklahoma, where the Anadarko and Arkoma Basins are located. Historically, an average of one to two ML[i] ≥ 3.0 earthquakes has occurred in Oklahoma annually. The number of ML ≥ 3.0 earthquakes occurring in the state, however, rose to over 900 in 2015.

While the seismicity rate began to decline in 2016, the yearly total seismic moment[j] of Oklahoma remained high in response to three Mw[k] ≥ 5.0 earthquakes occurring during the year, including the Pawnee earthquake, the largest earthquake (5.8 Mw) ever recorded for the state of Oklahoma. The seismicity rate increase has generally been attributed to the disposal of large volumes of produced water into the Arbuckle Group basin (Haffener, Chen, and Murray, 2018).

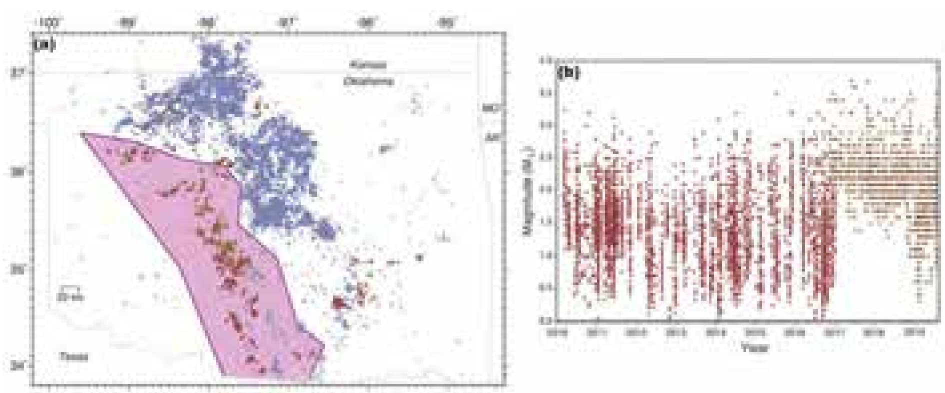
[i] ML refers to the magnitude on the Richter scale, where M stands for magnitude and L stands for local.

[j] Seismic moment represents a measure of the size of an earthquake, depending on the area of rupture, the rigidity of the rock, and the amount of slip from faulting.

[k] Mw is known as the moment magnitude of an earthquake. For very large earthquakes, moment magnitude gives the most reliable estimate of earthquake size.

Exhibit 5-3 shows the location (left) and magnitude (right) of induced seismic events in Oklahoma between 2010 and 2020. In the map on the left, seismic events from natural causes are represented by the blue circles, while induced seismic events are represented by the red (Skoumal et al., 2018) and orange circles (Shemeta, Brooks, and Lord, 2019). The graph on the right shows the number and magnitude of the induced seismic events over time (Skoumal et al., 2018; Shemeta, Brooks, and Lord, 2019).

Exhibit 5-3. Induced seismicity events in Oklahoma



Used with permission from Schultz et al. (2020)

5.1.3 Fayetteville Formation in the Arkoma Basin of Arkansas

Following the success of the Barnett Shale (Fort Worth Basin, Texas) the Fayetteville Formation in Arkansas became an early target for continued shale gas development in the United States. This unconventional play runs east to west across north central Arkansas, extending across nearly 150 km. By 2005, horizontal well completions in the middle to lower organic rich facies at depths typically 1–2 km were coming online and, by 2009, 0.5 Tcf of gas was being produced per year (Browning et al., 2014).

The Fayetteville Formation has a history of seismicity that dates back to before the region was developed for oil and natural gas extraction. In September 2010, a series of seismic events reaching magnitudes close to 5.0 Mw on the Richter Scale occurred along the Guy-Greenbrier Fault within the basin. Not long after, on February 28, 2011, a 4.7 Mw earthquake—the largest ever recorded—occurred within the basin. This led to concerns that even larger earthquakes could potentially occur in the area, which resulted in an emergency shutdown order for any injections being put in place by the Arkansas Oil and Gas Commission. Analysis of the seismicity, injection patterns, and pore pressure diffusion built a strong case for the activation of the Guy-Greenbrier Fault by wastewater disposal (Horton, 2012; Ogwari, Horton, and Ausbrook, 2016; Ogwari and Horton, 2016; Park et al., 2020). In the neighboring states of Oklahoma and Texas, wastewater disposal by injection is understood to be the primary driver of induced seismicity.

5.1.4 Eagle Ford Shale Play in the Western Gulf Basin of Texas

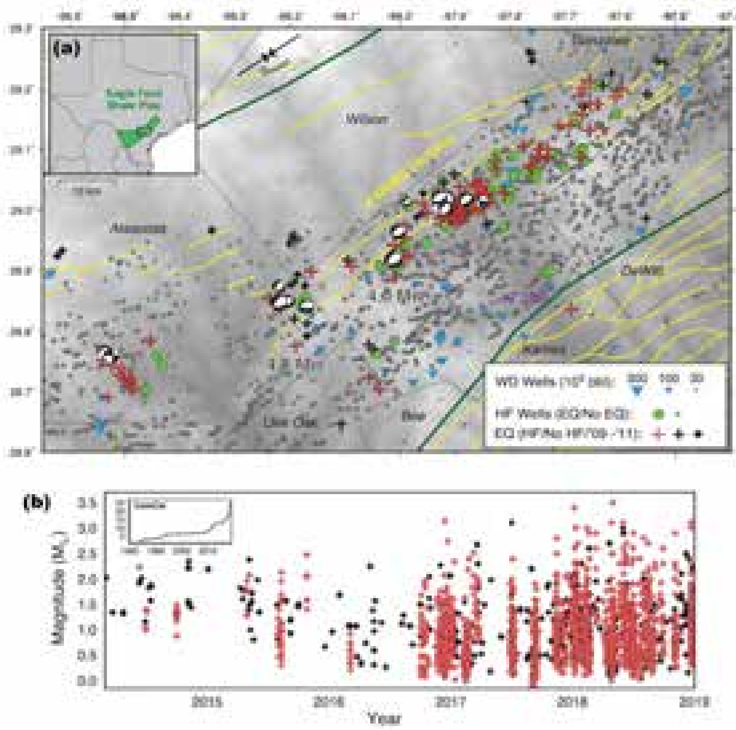
Texas has a long history of active oil and natural gas production, hydraulic fracturing, wastewater disposal, and general seismicity, some of which occurs within or near areas of pervasive faulting (see Exhibit 5-4a) (Ewing, 1990; Frohlich et al., 2016). Advancements in horizontal drilling and hydraulic fracturing since 2008 have prompted the Eagle Ford shale play to focus on hydrocarbon production from the Upper Cretaceous Eagle Ford and Austin Chalk Formations (Frohlich and Brunt, 2013; Martin et al., 2011; Pearson, 2012; RRC, 2019).

In 2018, the rate at which ML ≥ 3.0 earthquakes occurred in the Eagle Ford shale play was 33 times higher than background levels (3 earthquakes per 10 years during 1980–2010; see Exhibit 5-4b). Fasola et al. (2019) investigated seismicity that has occurred since 2014, in an effort to identify how hydraulic fracturing has contributed to seismicity within the play. Comparing both times and locations of hydraulic fracturing to a catalog of seismic activity, Fasola et al. (2019) suggest more than 85 percent of the seismicity that occurred was spatiotemporally correlated with hydraulic fracturing. More specifically, there were 94 ML ≥ 2.0 earthquakes correlated with 211 hydraulic fracturing well laterals.

Exhibit 5-4a provides a map from the Texas Seismological Network highlighting earthquakes (crosses) and focal mechanisms (beach balls) that have occurred since 2017. Hydraulic fracturing wells are indicated by black circles in Exhibit 5-4. Correlated earthquakes and hydraulic fracturing wells are displayed as red plus signs and green circles, respectively. Black diamonds show the earthquakes that occurred during 2009–2011 (Frohlich and Brunt, 2013). Purple square shows the seismic station (735B) used for template matching. Wastewater disposal wells are provided as teal triangles sized by median monthly volumes. Arrows show regional orientation (Lund Snee and Zoback, 2016). Faults (Ewing, 1990) are in yellow.

Exhibit 5-4b provides the magnitudes of the various earthquakes both correlated and not correlated with hydraulic fracturing that occurred annually after 2011 within the play (the black and red plus signs shown in Exhibit 5-4a). The inset shows the cumulative number of earthquakes (magnitude ≥ 3.0) occurring in the area, available from the United States Geological Survey (USGS) Comprehensive Catalog.

Exhibit 5-4. Locations and timings of Eagle Ford hydraulic fracturing induced events



Used with permission from Schultz et al. (2020)

5.2 Current Induced Seismicity Research and Development

As mentioned in Chapter 1, state regulators have long been focused on identifying the precise location and magnitude of earthquakes and determining their cause. When earthquakes can be linked to wastewater injection, regulators respond by ordering operators to cease or limit either injection rates and/or water volumes in nearby wells (EPA UIC National Technical Workgroup, 2015). Many regulators also require that new injection wells avoid areas near known active faults. In Oklahoma, these techniques have effectively reduced the number of felt earthquakes.

Similar procedures have been applied to hydraulic fracturing operations in some states. That is, when earthquakes are detected, operations are either modified or suspended (AGI, 2017). Oklahoma, Texas, and Ohio have all taken steps to mitigate induced seismicity linked to hydraulic fracturing.

In Texas, the state's Center for Integrated Seismicity Research (TexNet) is charged with monitoring, locating, and cataloging seismicity across the state. Capable of detecting and locating earthquakes with magnitudes ≥ 2.0, TexNet's backbone network improves investigations of ongoing sequences of seismic activity by deploying temporary seismic monitoring stations and conducting site-specific assessments (Young et al., 2017). TexNet continues to conduct fundamental and applied research to better understand both naturally and potentially induced seismic events that are occurring across the state of Texas, their associated risks, and potential strategies for communicating with stakeholders and responding to public concerns raised regarding seismicity (Young et al., 2017).

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6 Land Use and Development

Land presents a critical yet often overlooked constraint to energy development, including the development of domestic natural gas. The growing land use footprint of energy development, termed "energy sprawl," likely causes significant habitat loss and fragmentation with associated impacts to biodiversity and ecosystem services (McDonald et al., 2009). Natural gas is growing as a transition fuel during the grid decarbonization process in the United States, making an understanding of its land use implications a critical and necessary consideration (Dai et al. 2023).

Commented [HSAJ6]: Comment for FECM - In some cases literature that predates 2014 is referenced in Ch. 6. The findings from these studies are still true today but they aren't common knowledge so we were inclined to leave those references in. Please advise in your comments how you would prefer we proceed.

Expanding energy development is now the primary source of anthropogenic land cover change in natural ecosystems in North America (Allred et al., 2015; Trainor, McDonald, and Fargione, 2016), including eastern deciduous forests, boreal forests, prairie grasslands, sagebrush-steppe, and deserts (Copeland, Pocewicz, Kiesecker, 2011; McClung and Moran, 2018; Appiah, Opio, Donnelly, 2019). Land use and development issues associated with natural gas production include local surface disturbance; cumulative landscape impacts; habitat fragmentation; and increased traffic, noise, and light.

The Citizens Marcellus Shale Coalition (CMSC) (2011) explored two issues related to impacts of shale gas production on public lands and the other industries that rely on these lands. They also explored impacts on private property rights. CMSC stated that shale gas development must consider the cumulative impacts on state parks and forests and on timber and tourism industries as part of responsible stewardship of public resources. Property rights and environmental degradation are a growing public concern, and eminent domain laws, drill spacing requirements, and grouping of leased lands could help protect these rights. These findings are still relevant to current natural gas extraction.

6.1 Surface Disturbance and Landscape Impacts

The infrastructure needed to support the supply chain of electricity produced from natural gas involves production sites (production pads and their access roads), transportation facilities (e.g., gathering and transmission pipelines for natural gas), processing facilities, and power plants (end-use) (Dai et al., 2023). Such activities can disturb the Earth's surface, the impacts of which can extend over large areas and result in habitat fragmentation that impacts both plant and animal species. Mitigation options include adoption of best practices for site development and restoration, avoidance of sensitive areas, and minimization of impacts to disturbed areas.

Dai et al. (2023) used machine learning, remote sensing, and geographic information systems to obtain spatially explicit information on the land required to support natural gas production. Their analysis considered land use across five life cycle stages of natural gas produced for electricity production from wells (production stage), natural gas transportation via gathering pipelines (gathering stage), natural gas processing (processing stage), natural gas transportation via transmission pipelines (transmission stage), and gas consumption as fuel through combustion in gas-fired power plants (use stage).

For the production stage, Dai et al. (2023) mapped land-use for 100,009 wells located at 75,915 different well pads. Among the 100,009 wells examined, 31,716 were co-located. In non-

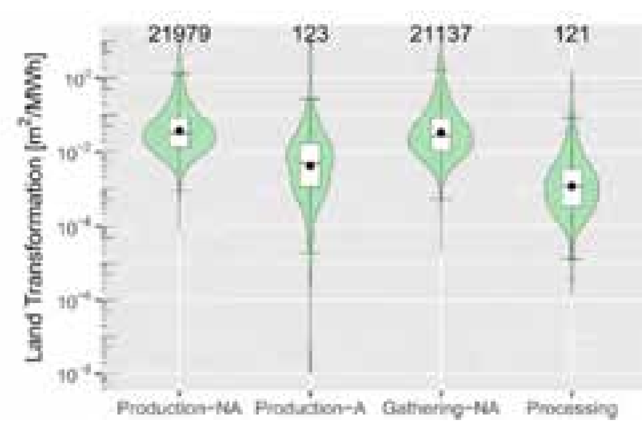
agricultural areas, results suggest vertical wells occupy ~4,000 square meters (m^2) less land per site than horizontal-/directional-drilled wells. During the gathering stage in both agricultural and non-agricultural areas, sites with horizontal-/directional-drilled wells require ~230 meters less pipeline in length on average than sites with vertically drilled wells. Whereas due to the requirement for larger width of right-of-way, the extent of land used is almost doubled for sites with horizontal-/directional-drilled wells than those with vertical well. Results from Dai et al. (2023) are summarized in Exhibit 6-1.

Exhibit 6-1. Land use throughout the life cycle of gas-fired electricity

Stage			Unit	Average
Production	Agricultural	Directional	m^2 per site	9,346
		Vertical	m^2 per site	2,100
	Non-agricultural	Directional	m^2 per site	18,170
		Vertical	m^2 per site	14,090
Transportation by gathering	Length	Directional	m^2 per site	597
		Vertical	m^2 per site	818
	Area	Directional	m^2 per site	20,157
		Vertical	m^2 per site	10,128
Processing			m^2 per (MM cubic feet per day)	4,318

Exhibit 6-2 from this study illustrates the land transformation by stage, showing that production in non-agricultural areas utilizes more land than agricultural areas.

Exhibit 6-2. Land transformation in natural gas production



Note: NA = non-agricultural area, A = agricultural area

Used with permission from Dai et al. (2023)

Notably, technological advancements will play a significant role in decreasing the amount of land that will be transformed during the life cycle stages of production, gathering, and consumption of natural gas – for both vertical and horizontal-/directional wells. Directional drilling technology enables more than 20 wells to be drilled in a single pad, and each well could have a comparable amount of lifetime production. As a result, the total amount of production per site with directional-drilled wells can be an order of magnitude higher than the conventional sites with vertical drilled wells, which dramatically lowers the land transformation for production and gathering (Dai et al., 2023).

6.2 HABITAT FRAGMENTATION

The development of drilling sites for natural gas production can disrupt the habitat of both plant and animal species in several different ways. For example, habitat fragmentation can occur when infrastructure must be installed, or land clearing must take place to allow access to a well location. Land area that is occupied with well pads and the construction of pipelines are two of the leading causes of habitat fragmentation (Cooper, Stamford, and Azapagic, 2016; Langlois, Drohan, and Brittingham, 2017). The land area occupied for shale gas extraction typically can be reduced through the use of multi-well pads at one site, which have a surface footprint (and water use) per well two to four times lower than that of single-well pad sites (Manda et al., 2014).

The construction and installation of the infrastructure necessary for natural gas development can lead to a habitat being converted from a large contiguous patch of similar environments to several smaller, isolated environments. When contiguous core habitats are fragmented into smaller patches, many sensitive species are unable or unwilling to cross non-habitat regions to reach alternative habitat patches. While habitat loss can have an immediate impact on wildlife population, the ecological response to fragmentation is lagged, and affects different species at varying timescales (Makki et al., 2013).

A secondary impact of fragmentation is the creation of edges. Edges are generally defined as the 100 meters between core forest and non-forest habitat (PADEP, 2014; Kargbo, Wilhelm, and Campbell, 2010; Johnson et al., 2010). New edges affect the physical or biological conditions at the ecosystem boundary and within adjacent ecosystems (Fischer and Lindenmayer, 2007). Edge effects are believed to be detrimental by increasing predation, changing lighting and humidity, and increasing the presence of invasive species (Johnson et al., 2010).

Exhibit 6-3 provides a schematic depicting the habitat loss and fragmentation from natural gas production. Exhibit 6-3 progresses from infrastructure development that has quantifiable land impacts leading to temporally extended land changes—impacts that account for habitat loss and fragmentation.

Exhibit 6-3. General procedure for depicting land disturbance from natural gas extraction

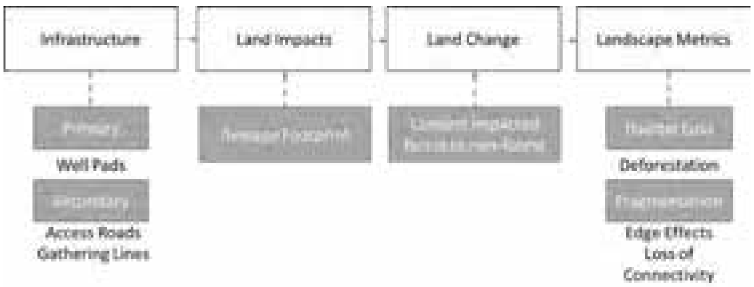
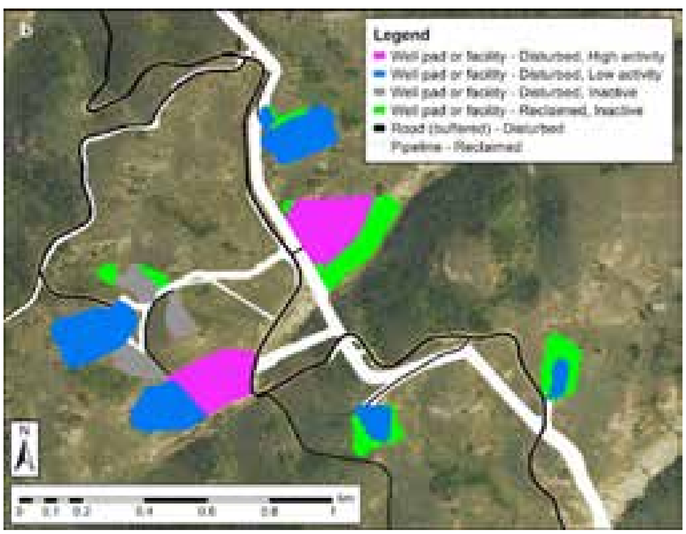


Exhibit 6-4 provides an example of energy infrastructure features digitized from 2013 National Agricultural Inventory Program satellite imagery overlaid with well locations reported in Colorado Oil and Gas Conservation Commission (COGCC) data. Each mapped feature (or portion thereof) was classified by type (well pad, facility, road, or pipeline) and by surface type (disturbed or reclaimed), and well pads and facilities (or portions thereof) were assigned an activity status (high, low, or inactive) (Walker et al., 2020).

Exhibit 6-4. Footprint of a well pad and surrounding infrastructure



Used with permission from Walker et al. (2020)

Each region where natural gas extraction takes place has unique species and habitat therein. Within those species, some are more greatly affected than others, whether it be core habitat fragmentation or edging.

Long-term effects of shale gas production on habitat disturbance will have to be evaluated as the development of these resources continues. Mitigation measures such as avoidance, best management practices, and prompt reclamation of the drilling site have been put forward as ways to best minimize the possible impacts that shale gas production may have on habitats. Habitat disruption can also result from a lack of surface water availability in response to withdrawals to support natural gas production and quality from erosion and chemical spills.[l]

6.3 Noise, Light, and Traffic

Natural gas development processes are associated with both noise and light pollution, which can contribute to stress among those living in nearby communities (Down, Armes, Jackson, 2013; Korfmacher et al., 2013; Peduzzi et al., 2013; Witter et al., 2008a; Witter et al., 2008b). Construction, vehicles, drilling, compressors, flaring, and other processing equipment and facilities can all pollute through excessive noise and continuous illumination (Cleary, 2012).

6.3.1 Noise Pollution

A health impact assessment in Colorado identified noise pollution as an area of concern and noted that it occurs during drilling and completion operations, flaring, and because of vehicular traffic (Witter et al., 2013). Workers can be exposed to noise through many sources on site, including diesel engines, drilling, generators, mechanical brakes, heavy equipment operations, and radiator fans (Witter et al., 2014); therefore, hearing impairment is a noise-related health concern for workers on site.

The most recent study found using biomonitoring from Texas found residents reporting concerns about odors and noise apparently related to shale gas well and compressor station operations, although this was a separate, independent component from the biomonitoring portion designed to address residents' concerns (Texas Department of State Health Services, 2010). While the authors noted that it was difficult to determine if the levels were above acceptable limits that may be harmful to human health, and that noise may affect quality of life, this is speculative because noise levels were not measured to establish decibels of noise in the study area.

Noise standards for a single well pad may be met; however, the cumulative effects of multiple operations in one area might exceed these established decibel levels. In terms of setback distances, some noise regulations distinguish between maximum decibels for day and night, while others distinguish between maximum decibels for certain phases of the operation such as drilling, fracturing, and production; however, there is often variability and, in some areas, it is suggested that distances are set as monitoring points, not necessarily points indicative of being protective of health (Fry, 2013).

6.3.2 Light Pollution

Light pollution has significant implications for the environment and public health, and its effects have become more pronounced over time due to the increasing extent and radiance of

[l] The potential water use implications of natural gas are discussed in Chapter 4 – Water Use and Quality.

artificially lit areas (Kyba, 2017). Substantial economic values have been attached to affected outcomes, such as biodiversity, recreation, and public health. With respect to human health, artificial lights at night are associated with sleep deprivation and mental health (Patel, 2019; Xiao, 2020); sleep deprivation, in turn, has been shown to reduce cognition and labor market productivity, as well as elevate mortality risks associated with dementia, heart attacks, and vehicle accidents (Hafner et al., 2017; Paksarian et al., 2020; Ma et al., 2020; Jin and Ziebarth, 2020; Prats-Uribe, Tobías, and Prieto-Alhambra, 2018.). A study in Australia quantified the financial and non-financial costs of inadequate sleep in 2016–2017 to be $45 B (Hillman et al., 2018) and another study estimates that $680 B is lost due to sleep deprivation across five Organisation for Economic Co-operation and Development (OECD) countries (Hafner et al., 2017; Boslett, 2021). The impacts of light pollution also extend to human health and well-being. Artificial light disrupts melatonin secretion and circadian rhythm (Haim and Zubidat, 2015) with corresponding changes in mood regulation, depression, and sleeping disorders (Cho et al., 2016). Light pollution-driven changes in circadian rhythms may also have contributed to recent growth in obesity and metabolic dysfunction (Fonken et al., 2010). Growing laboratory and epidemiological evidence also support the long-hypothesized relationship between nighttime light exposure and cancer rates (Kerenyi, Pandula, and Feuer, 1990; Kloog, et al., 2010; Schwimmer et al. 2014; Jones, Pejchar, and Kiesecker, 2015).

Light pollution also has significant consequences for wildlife populations. It affects nighttime behavior and habits of terrestrial (Bennie et al., 2015) and marine (Davies et al., 2013) wildlife populations, particularly for species that use sun or moon light for guidance. It disrupts natural sleep and reproductive cycles, geographical orientation, and predator-prey relationships (Longcore and Rich, 2004). Other effects of light pollution include changes in bird singing behavior (Miller, 2006), estrus patterns in nocturnal primates (LeTallec, Théry, and Perret, 2015), insect pollination (MacGregor, 2015), and fish biological rhythms (Brüning et al., 2015). These impacts have led to ecosystem-wide changes in biodiversity and growing disparities between entire taxonomic groups (Davies et al., 2013).

While there is some work speculating that light pollution associated with shale development induces psychosocial stress (Fisher et al., 2017), sleep and mental health issues (Casey et al., 2018), and adverse impacts to local ecosystems (Kiviat, 2013), the literature directly connecting the recent resource boom to light pollution is extremely limited. Importantly, no work has documented the causal impact of U.S. shale development on light pollution.

6.3.3 Traffic

Traffic may increase in any given area because of unconventional natural gas development, but the magnitude of this increase has not been studied in depth. The phases of development that require the most traffic load involve well pad construction, drilling and well completion, and pipeline construction (Witter et al., 2014). It appears that changes in traffic patterns will be dependent upon the area and either the individual project or the cumulative effects of multiple projects in an area. Industrial truck traffic can be detrimental to health-related air quality due to vehicle exhaust, as well as pose an increased risk of motor vehicle crashes.

In the *Revised Draft Supplemental Generic Environmental Impact Statement on The Oil, Gas and Solution Mining Regulatory Program*, the New York State Department of Environmental Conservation (NYSDEC) identified temporary but adverse noise and visual impacts from construction activity and increased truck traffic among the potential land-use environmental impacts associated with natural gas production (Witter et al., 2014). Significant adverse impacts in terms of damage to local and state roads could also result. Among mitigation measures described for environmental impacts, NYSDEC suggests imposing measures to reduce the adverse noise and visual impacts from well construction. A transportation plan could also be required that would include proposed truck routes and assess road conditions along the proposed routes. Exhibit 6-5 tabulates the number of truck trips for a typical shale gas well (Massachusetts Institute of Technology [MIT], 2011).

Exhibit 6-5. Truck trips for a typical shale gas well drilling and completion

Activity	1 Rig, 1 Well	2 Rigs, 8 Wells
Pad and Road Construction	10–45	10–45
Drilling Rig	300	60
Drilling Fluid and Materials	25–50	200–400
Drilling Equipment (casing, drill pipe, etc.)	25–50	200–400
Completion Rig	15	30
Completion Fluid and Materials	10–20	80–160
Completion Equipment (pipe, wellhead, etc.)	5	10
Fracturing Equipment (pump trucks, tanks, etc.)	150–200	300–400
Fracture Water	400–600	3,200–4,800
Fracture Sand	20–25	160–200
Flowback Water Disposal	200–300	1,600–2,400
TOTAL	1,160–1,610	5,850–8,905

The large volumes of water involved in hydraulic fracturing operations can create high volumes of road traffic given the majority of the water used for fracking is transported by truck. It should be noted that the large number of traffic movements shown in Exhibit 6-5 are worst-case estimates. In particular, re-use of flowback wastewater significantly reduces the amount of road traffic associated with hauling water, which represents much of the traffic movement. Furthermore, large-scale operators are also using pipelines to transport water to the site, substantially reducing the amount of road traffic (MIT, 2011).

The Eagle Ford Shale Task Force Report for the RRC identified increased traffic and deterioration of roads and bridges among the infrastructure impacts from shale gas development (Porter, 2013). Exhibit 6-6 lists estimates of the number of truck-trips-per-shale-gas-well in the Eagle Ford (Porter, 2013).

Exhibit 6-6. Loaded truck trips per gas well

Activity	Number of Loaded Trucks
Bring well into production	1,184
Maintain production (per year)	Up to 353
Re-fracturing (every 5 years)	997

These impacts are enough of a concern that the task force considered alternative financing methods to help meet the increased demands on roads and bridges (Porter, 2013).

Upadhyay and Bu (2010) surveyed the visual impacts of Marcellus drilling and production sites in Pennsylvania. They reviewed the drilling process, assessed direct visual impacts, and compared the results to the impacts of other technologies (e.g., windmills and cell towers). They also studied drill-pad density from map and aerial perspectives to examine the likelihood of seeing drill towers across a landscape, and the modeled potential impacts for increased drilling, making the following conclusions:

- Serious impacts from light and noise are a potential problem within a small radius of drilling sites.
- Indirect impacts like increased truck traffic, equipment storage, and temporary structures compose the most salient visual impacts, rather than the drill pads themselves.
- Timelines for site restoration of visual impacts vary significantly.

Upadhyay and Bu (2010) recommended that visual impacts be addressed during the siting and design phase and that nighttime impacts could be avoided by pointing lights downward.

The RFF (2013) report also gave several options in their survey of experts under the category of community disruption. Included in this category, as well as in the habitat fragmentation section, were such risks as light pollution, noise pollution, odor, and road congestion. The industry respondents identified a number of these community disruptions as risk pathways of high priorities, while the other respondent groups identified more conventional (e.g., air pollution, water pollution) risks.

6.4 Reducing Potential Land Use Impacts

Linear infrastructure on private land contributed to the greatest loss of core forest. Unlike private land, the majority of pipelines on public land were collocated with roads, which likely reduced habitat fragmentation. Large public landowners can negotiate with a relatively small number of gas operators compared to private landowners (PADEP, 2016); therefore, individual landowners can make deals with different operators such that two different operators end up working in close proximity and duplicating infrastructure on private land rather than public land.

6.4.1 Mitigation Options for Habitat Fragmentation Impacts

Mitigation strategies related to pipelines enacted by state agencies have shown that fragmentation on public lands has been reduced more than on private lands, especially when multiple mitigation strategies are implemented on public land with the goal of reducing surface disturbance and impacts to forest. For example, the Pennsylvania Department of Conservation & Natural Resources (PADCNR) can limit the number of well pads per leased track (PADCNR, 2014). This method constrains development intensity (i.e., pad density) and encourages operators to increase the number of wells per pad thereby maximizing per well drainage and efficiency (DOE, 2016). A widely implemented mitigation policy on state forest land requires gas infrastructure to utilize existing surface disturbance whenever feasible, including road networks, right-of-way corridors, or abandoned mine lands (PADCNR, 2014).

Similarly, Abrahams, Griffin, and Matthews (2015) found that requiring pipelines to follow existing roads prevented further fragmentation in a core forested region while allowing full extraction of the shale resource. Collocation is widely accepted as an effective mitigation strategy to reduce surface impacts (Bearer et al., 2012; Racicot et al., 2014); however, it rarely occurs on private land.

6.4.2 Reducing Light Pollution

Even two decades after the establishment of designated programs by NGOs to recognize and certify the quality of night skies and nighttime darkness resources, the very notion of what a “dark sky” is remains unsettled from a scientific standpoint (Crumey, 2014); while appropriate instrumentation can quantify night sky brightness, it cannot properly account for the human aesthetic experience of natural night. However, various lines of research increasingly suggest that unsafe thresholds of exposure to artificial light at night in terms of intensity, duration, wavelength, and timing likely exist for humans, plants, and animals. In this sense, light-sensing technologies applied in the field could effectively serve as “dosimeters” for monitoring these exposure parameters (Barentine, 2019).

6.5 DOE Research and Development and Analysis

An independent review of the literature suggests there is currently no R&D or analysis with respect to land use, habitat fragmentation, or light, noise, or traffic pollution being conducted by DOE.

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Task #	2.21.4.1.EMA
Title of Report	POTENTIAL ENVIRONMENTAL IMPACTS ASSOCIATED WITH UNCONVENTIONAL NATURAL GAS

Image 1:

Full reference for NETL report	**BP.** (2017). Unconventional gas and hydraulic fracturing. [Online]. BP. Available from https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/sustainability/issue-briefings/bp-unconventional-gas-issue-briefing-2016.pdf
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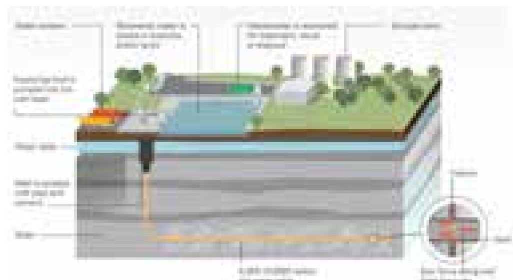
***Image**	**Exhibit Error! No text of specified style in document.-1. Schematic geology of natural gas resources (3D)** 
Notes	Permission pending from BP (2017)

Image 2:

Full reference for NETL report	Richardson, N., Gottlieb, M., Krupnick, A., Wiseman, H. (2013). The State of Shale Gas Regulation. [Online]. Resources for the Future. Available from https://www.rff.org/publications/reports/the-state-of-state-shale-gas-regulation/
Copyright holder	RFF
***Image**	**Exhibit 1-10. Water withdrawal regulations by state** 
Notes	Used with permission from Richardson et al. (2013)

Image 3:

Full reference for NETL report	Rutherford, J.S., Sherwin, E.D., Ravikumar, A.P. et al. (2021). Closing the methane gap in US oil and natural gas production emissions inventories. Nat Commun, 12, 4715. https://doi.org/10.1038/s41467-021-25017-4

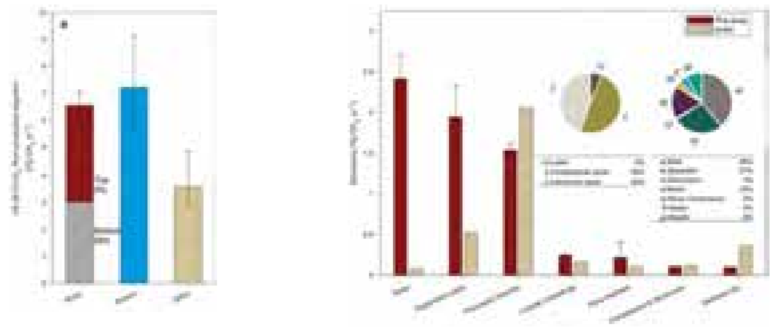
Copyright holder	Rutherford et al.
***Image**	**Exhibit Error! No text of specified style in document.-2. Comparison of GHG Emissions Results from Rutherford et al., Alvarez, et al., and EPA GHGI** 
Notes	Open access

Image 4:

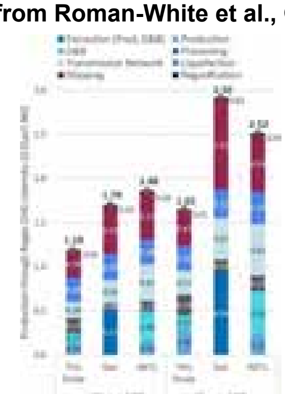
Full reference for NETL report	Roman-White, S.A., Littlefield, J.A., Fleury, K.G., Allen, D.T., Balcombe, P., Konschnik, K.E., Ewing, J., Ross, G.B., and George, F. (2021). LNG Supply Chains: A supplier-specific life-cycle assessment for improved emission accounting. ACS Sustainable Chemistry; Engineering, 9(32), 10857–10867. https://doi.org/10.1021/acssuschemeng.1c03307
Copyright holder	American Chemical Society
***Image**	**Exhibit Error! No text of specified style in document.-10. Comparison of GHG emissions results from Roman-White et al., Gan et al., and NETL** 
Notes	Open access

Image 5:

Full reference for NETL report	Wollin, K.-M., Damm, G., Foth, H., Freyberger, A., Gebel, T., Mangerich, A., Gundert-Remy, U., Partosch, F., Röhl, C., Schupp, T., and Hengstler, J. G. (2020). Critical evaluation of human health risks due to hydraulic fracturing in natural gas and petroleum production. Archives of Toxicology, 94(4), 967–1016. https://doi.org/10.1007/s00204-020-02758-7
Copyright holder	Wollin et al.

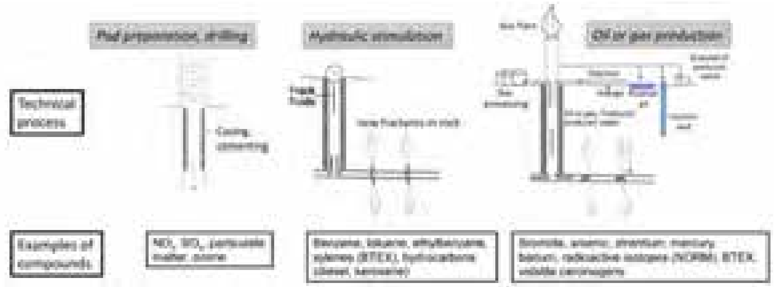
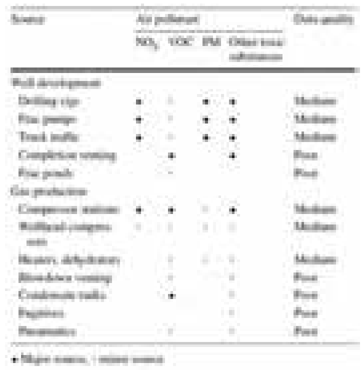
***Image**	**Exhibit Error! No text of specified style in document.-2. Illustration of supply chain steps where upstream air pollution occurs** 
Notes	Open access

Image 6:

Full reference for NETL report	Wollin, K.-M., Damm, G., Foth, H., Freyberger, A., Gebel, T., Mangerich, A., Gundert-Remy, U., Partosch, F., Röhl, C., Schupp, T., and Hengstler, J. G. (2020). Critical evaluation of human health risks due to hydraulic fracturing in natural gas and petroleum production. Archives of Toxicology, 94(4), 967–1016. https://doi.org/10.1007/s00204-020-02758-7
Copyright holder	Wollin et al.
***Image**	**Exhibit Error! No text of specified style in document.-3. Perspective of non-GHG air pollutant by supply chain step or equipment** 
Notes	Open access

Source	Air pollutant				Data quality
	NO_x	VOC	PM	Other toxic substances	
Well development					
Drilling rigs	•	·	•	•	Medium
Frac pumps	•	·	•	•	Medium
Truck traffic	•	·	•	•	Medium
Completion venting		•		•	Poor
Frac ponds		·			Poor
Gas production					
Compressor stations	•	•	·	•	Medium
Wellhead compressors	·	·	·	·	Medium
Heaters, dehydrators		·	·	·	Medium
Blowdown venting		·		·	Poor
Condensate tanks		•		·	Poor
Fugitives				·	Poor
Pneumatics		·		·	Poor

• Major source, · minor source

Image 7:

Full reference for NETL report	Mayfield, E.N., Cohon, J.L., Muller, N.Z. et al. (2019). Cumulative environmental and employment impacts of the shale gas boom. Nat Sustain 2: 1122–1131. https://doi.org/10.1038/s41893-019-0420-1
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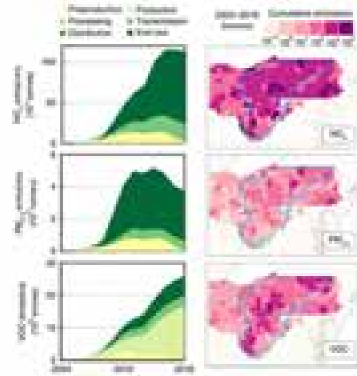
*Image	**Exhibit 3 44. Annual (left graphs) and cumulative (right graphs) (2004–2016) NOx, PM2.5, and VOC emissions from natural gas supply chain within Pennsylvania, Ohio, and West Virginia** 
Notes	Permission pending from Mayfield et al. (2019)

Image 8:

Full reference for NETL report	Scanlon, B.R., Ikonnikova, S., Yang, Q., and Reedy, R.C. (2020a). Will Water Issues Constrain Oil and Gas Production in the United States? Environmental Science & Technology, 54(6): 3510–3519, https://doi.org/10.1021/acs.est.9b06390
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*Image	**Exhibit Error! No text of specified style in document.-3. Map showing ratio between produced water and fracking water demand for major shale basins** 
Notes	Free to use under ACS's AuthorChoice/Editors' Choice

Image 9:

Full reference for NETL report	Kondash, A.J., Lauer, N.E., and Vengosh A. (2018). The intensification of the water footprint of hydraulic fracturing, Science Advances, 4(8).
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Contact	akondash@rti.org

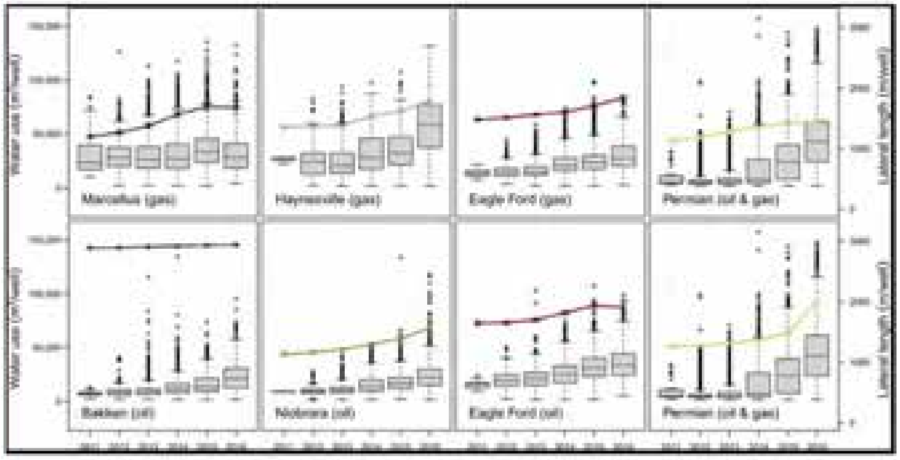
*Image	**Exhibit Error! No text of specified style in document.-4. Water usage and lateral length by shale play** 
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Image 10:

Full reference for NETL report	Kondash, A.J., Lauer, N.E., and Vengosh A. (2018). The intensification of the water footprint of hydraulic fracturing, Science Advances, 4(8).
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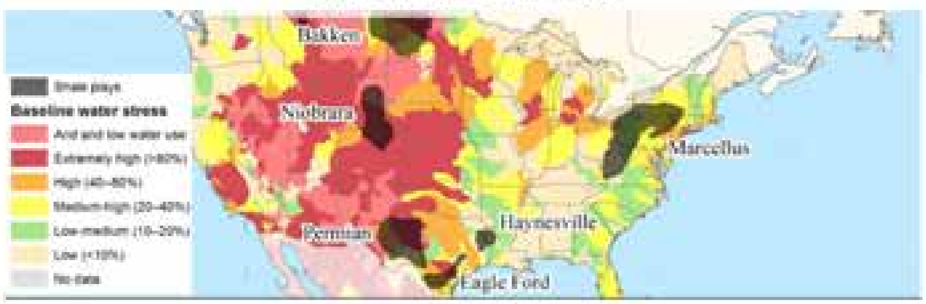
*Image	**Exhibit Error! No text of specified style in document.-5. Baseline water stress and location of shale plays** 
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Image 11:

Full reference for NETL report	Scanlon, B.R., Reedy, R.C., Xu, P., Engle, M., Nicot, J.-P., Yoxtheimer, D., Yang, Q., Ikonnikova, S. (2020b) Can we beneficially reuse produced water from oil and gas extraction in the U.S.? Science of The Total Environment, Volume 717, 15 May 2020, 137085. Available from https://www.sciencedirect.com/science/article/pii/S0048969720305957#f0010
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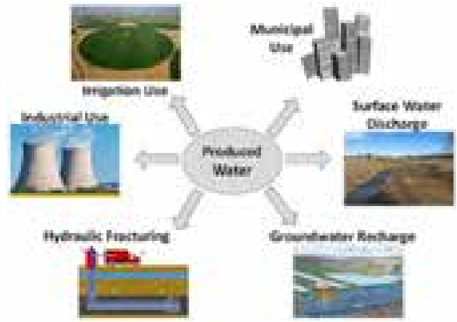
*Image	**Exhibit 4-5. Major Produced Water Reuse Outlets** 
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Image 12:

Full reference for NETL report	Schultz, R., Skoumal, R.J., Brudzinski, M.R., Eaton, D., Baptie, B., and Ellsworth, W. (2020). Hydraulic Fracturing-Induced Seismicity. [Online] Review of Geophysics, 58(3). Available from https://doi.org/10.1029/2019RG000695
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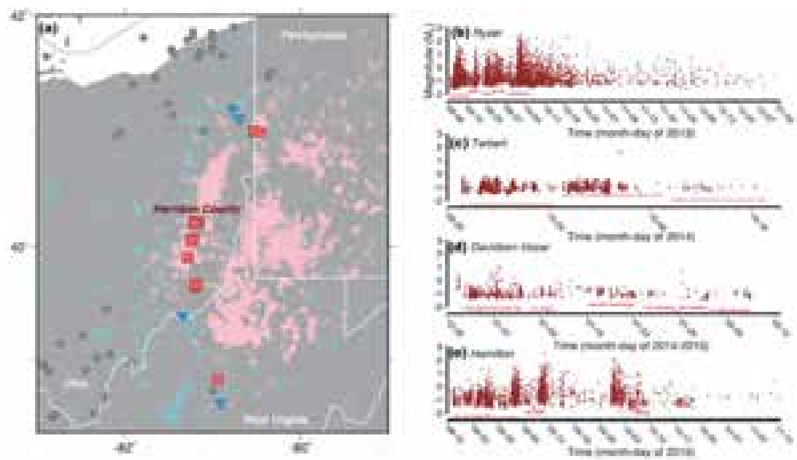
*Image	**Exhibit Error! No text of specified style in document.-6. Location and timing of induced and natural seismic events in the Appalachian Basin** 
Notes	Open access

Image 13:

Full reference for NETL report	Schultz, R., Skoumal, R.J., Brudzinski, M.R., Eaton, D., Baptie, B., and Ellsworth, W. (2020). Hydraulic Fracturing-Induced Seismicity. [Online] Review of Geophysics, 58(3). Available from https://doi.org/10.1029/2019RG000695
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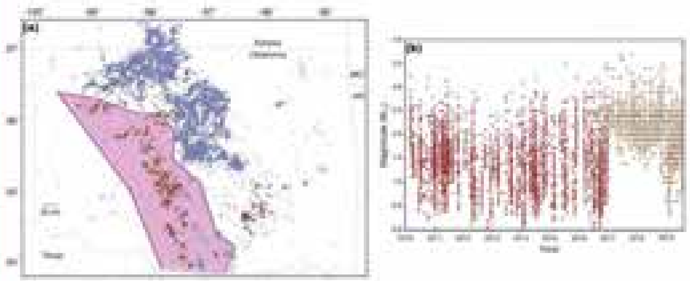
*Image	**Exhibit Error! No text of specified style in document.-7. Induced seismicity events in Oklahoma** 
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Image 14:

Full reference for NETL report	Schultz, R., Skoumal, R.J., Brudzinski, M.R., Eaton, D., Baptie, B., and Ellsworth, W. (2020). Hydraulic Fracturing-Induced Seismicity. [Online] Review of Geophysics, 58(3). Available from https://doi.org/10.1029/2019RG000695
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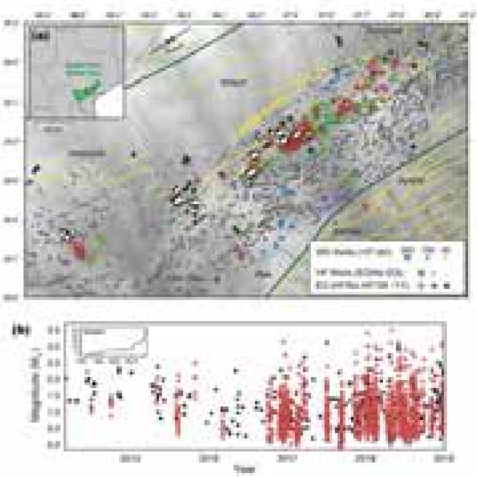
*Image	**Exhibit Error! No text of specified style in document.-8. Locations and timings of Eagle Ford hydraulic fracturing induced events** 
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Image 15:

Full reference for NETL report	Dai, T., Valanarasu, J.M.J., Patel, V.M., and Jordaan, S.M. (2023). The life cycle land use of natural gas-fired electricity in the US Western interconnection, Royal Society of Chemistry, Environ. Sci. Adv., 2, 815.
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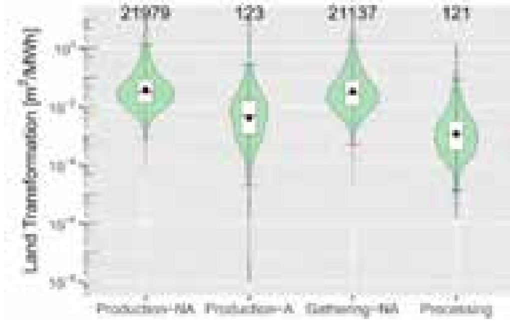
*Image	**Exhibit Error! No text of specified style in document.-9. Land transformation in natural gas production**  Note: NA = non-agricultural area, A = agricultural area
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Image 16:

Full reference for NETL report	Walker, B.L., Neubaum, M.A., Goforth, S.R., Flenner, M.M. (2020). Quantifying habitat loss and modification from recent expansion of energy infrastructure in an isolated, peripheral greater sage-grouse population, Journal of Environmental Management 255: 109819.
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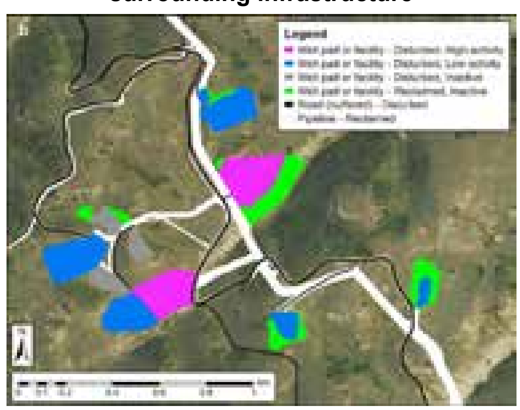
*Image	**Exhibit Error! No text of specified style in document.-10. Footprint of a well pad and surrounding infrastructure** 
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Image 17:

Full reference for NETL report	Spurlock, C.A., Elmallah, S., and Reames, T. G. (2022). Equitable deep decarbonization: A framework to facilitate energy justice-based multidisciplinary modeling. Energy Research & Social Science, 92: 102808.
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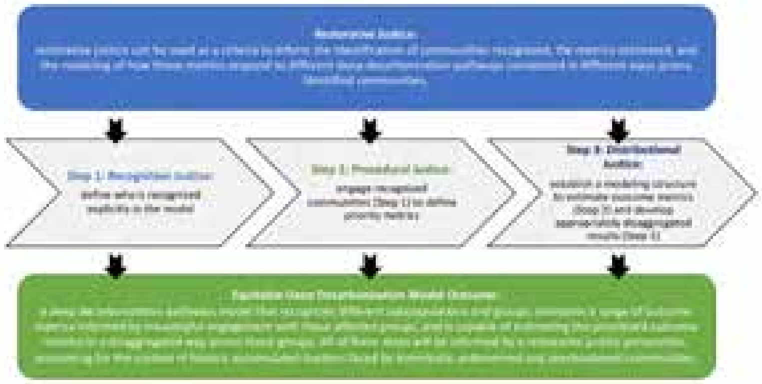
***Image**	**Exhibit Error! No text of specified style in document.-11. Flow of energy justice decisions** 
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Sent: Fri, 9 Jun 2023 19:56:12 +0000
To: Curry, Thomas; Sweeney, Amy; Skone, Timothy; Francisco De La Chesnaye
Cc: Wallace, Robert T. (CONTR); Adder, Justin (NETL)
Subject: LNG Regulatory Analysis Support FWP - Task 4 Env. Review Draft #1
Attachments: Draft_Env.Review_Task4_LNG_LNGRegAnalysisSupport_FWP-DraftPreDecisional_6_9_23.docx

Hi Tom, Amy, and Tim,

*DRAFT*DELIBERATIVE*PRE-DECISIONAL*

Good afternoon! Please find the first draft of the update to the 2014 Addendum to the Environmental Review attached. Chapters 1 through 6 are ready for your review. We should have Chapter 7 ready for your review by next Friday.

We look forward to receiving your feedback but are wondering if it would be possible to receive all comments at once?

Thank you!

Sincerely,
Amanda J. Harker Steele, Ph.D. (she/her)
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NETL NATIONAL ENERGY TECHNOLOGY LABORATORY

Document 65 - Attachment

DRAFT*DELIBERATIVE*PRE-DECISIONAL

NATIONAL ENERGY TECHNOLOGY LABORATORY

ENVIRONMENTAL IMPACTS OF UNCONVENTIONAL NATURAL GAS DEVELOPMENT AND PRODUCTION

June 9, 2023

DOE/NETL-2014/1651

Preliminary – Do Not Cite or Quote

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Commented [HH1]: Will the date and document number need to be updated?

Commented [RW2R1]: Yes.

Commented [HSAJ3R1]: We will update once finalized. We will also remove any instances of DRAFT*DELIBERATIVE*PRE-DECISIONAL once finalized as well.

*DRAFT*DELIBERATIVE*PRE-DECISIONAL*

Disclaimer

Hartej Singh[2]*: Writing – Original Draft;* ***Michael Marquis***[2]*: Writing – Original Draft;* ***Odysseus Bostick***[2]*: Writing – Original Draft;* ***Robert Wallace***[2]*: Writing – Original Draft;* ***Amanda Harker Steele***[1*]*: Supervision*

[1]National Energy Technology Laboratory (NETL)
[2]NETL support contractor
*Corresponding contact: Amanda.HarkerSteele@netl.doe.gov

All images in this report were created by NETL, unless otherwise noted.

The authors wish to acknowledge the excellent guidance, contributions, and cooperation of the NETL staff, particularly:

Commented [HSAJ4]: To be completed in final draft.

Suggested Citation:
A. Zammerilli, R.C. Murray, T. Davis, J. Littlefield, "Environmental Impacts of Unconventional Natural Gas Development and Production," National Energy Technology Laboratory, Pittsburgh, May 28, 2014

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Commented [RW6R5]: Yes

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TABLE OF CONTENTS

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LIST OF EXHIBITS

ACRONYMS AND ABBREVIATIONS

ADEQ	Arkansas Department of Environmental Quality
AEO	Annual Energy Outlook
ANGA	America's Natural Gas Alliance
API	American Petroleum Institute
AR5	IPCC Fifth Assessment Report
B	Billion
Bbl	Barrel
Bcf	Billion cubic feet
BLM	Bureau of Land Management
BMP	Best management practice
BPC	Bipartisan Policy Center
Btu	British thermal unit
CBM	Coalbed methane
CFR	Code of Federal Regulations
CH_4	Methane
CMSC	Citizens Marcellus Shale Coalition
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_2e, CO_2-eq	Carbon dioxide equivalent
CRS	Congressional Research Service
DOE	Department of Energy
DOI	Department of the Interior
EDF	Environmental Defense Fund
EIA	Energy Information Administration
EPA	Environmental Protection Agency
ERP	Energy Resources Program
EUR	Estimated ultimate recovery
ft, FT	Foot
g	Gram
gal	Gallon
GAO	Government Accountability Office
GHG	Greenhouse gas
GWP	Global warming potential
GWPC	Groundwater Protection Council
ha	Hectare
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
kg	Kilogram
kJ	Kilojoule
km	Kilometer
km^2	Square kilometers
L	Liter
LCA	Life cycle analysis
LNG	Liquefied natural gas
M	Magnitude (Richter Scale)
Mcf, MCF	Thousand cubic feet
mg	Milligram
mi^2	Square mile
min	Minute
MIT	Massachusetts Institute of Technology
MJ	Megajoule
MM	Million
MMcf	Million cubic feet
MWh	Megawatt hour
N/A	Not applicable, not available
N_2	Nitrogen
N_2O	Nitrous oxide
NAS	National Academy of Sciences
NETL	National Energy Technology Laboratory
NGL	Natural gas liquids
NOAA	National Oceanic and Atmospheric Administration
NOV	Notice of violation
NO_x	Nitrogen oxides
NPS	National Park Service
NRC	National Research Council
NSPS	New Source Performance Standards
NYSDEC	New York State Department of Environmental Conservation
O_2	Oxygen
ODNR	Ohio Department of Natural Resources
OGS	Oklahoma Geological Survey
ONE Future	Our Nation's Energy Future
PM	Particulate matter
PRV	Pressure release valve

R&D	Research and development
REC	Reduced emission completion
RFF	Resources for the Future
scf	Standard cubic foot
SDWA	Safe Drinking Water Act
SEAB	Secretary of Energy Advisory Board
SF_6	Sulfur hexafluoride
SO_2	Sulfur dioxide
STAR	EPA's Science to Achieve Results
STRONGER	State Review of Oil and Natural Gas Environmental Regulations
T	Trillion
T-D, T&D	Transmission and distribution
Tcf	Trillion cubic feet
TDS	Total dissolved solids
TSS	Total suspended solids
TWDB	Texas Water Development Board
U.S.	United States
UIC	Underground Injection Control
USFS	U.S. Forest Service
USGS	U.S. Geological Survey
VOC	Volatile organic compound
WRI	World Resources Institute
yr	Year

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EXECUTIVE SUMMARY

The Department of Energy's (DOE) Natural Gas Regulatory Program is responsible for granting authorizations to import and/or export natural gas from and/or to foreign countries. An important dimension of considering whether to grant such authorizations is how the additional natural gas production and transport activities needed to support these exports and/or imports would impact the environment. As such, impacts are factors affecting the public's interest.

Although fundamental uncertainties exist regarding the exact amount of production and transport activities that would occur in response to additional authorizations for exports and/or imports of natural gas being granted, it is probable that both conventional and unconventional natural gas markets would be impacted. Accordingly, the DOE prepared has prepared this update to the 2014 Addendum to Environmental Review Documents Concerning Exports of Natural Gas from the United States (hereafter the 2014 Addendum) to provide the public with an improved understanding of the potential environmental impacts associated with such activities (DOE, 2014).

While DOE has made projections about the additional natural gas production that may result, we cannot estimate with certainty where, when, or by what method any additional natural gas would be produced/consumed/exported in response to the authorizations. Therefore, the DOE cannot meaningfully analyze the specific environmental impacts associated with such activities. As such, similar to the 2014 Addendum, this report provides only a review of the profusion of peer-reviewed, scientific literature produced related to the potential environmental consequences of expanding natural gas production and related activities.

Commented [HSAJ8]: Amy/Tom/Tim – We will update this based on the information reported by Task 1 & 2.

These publications build on a strong body of existing literature that traces the evolution of these resources from their conceptual stages in the 1970s to the technology advancements that started the shale gas boom in the early 2000s. Between 2009 and 2022, government, industry, academic, scientific, non-governmental, and citizen organizations added a substantial body of literature on the environmental impacts that could result from continuing the development of shale gas, tight gas sands, and coalbed methane resources, as well as liquified natural gas.

This report summarizes the current state of published descriptions of the potential environmental impacts of unconventional natural gas upstream operations within the Lower 48 United States. As a survey of the literature, this report is by no means exhaustive. The sources cited are all publicly available documents. Multiple publications on similar topics are compared based only on their technical and methodological distinctions. No opinion or endorsement of these works is intended or implied.

This report is divided into chapters that each contain a separate section of references so that each type of environmental impact can be explored further. The types of environmental impacts that are documented in this review include the following:

- Greenhouse gas (GHG) emissions and climate change (Chapter 2)
- Air quality (Chapter 3)
- Water use and quality (Chapter 4)

- Induced seismicity (Chapter 5)
- Land Use and Development (Chapter 6)
- Environmental & Social Justice (Chapter 7)

In addition to containing information on potential environmental impacts this report provides some background information on domestic natural gas production.

CHAPTER 1 – BACKGROUND

Innovations in existing oil and gas exploration and production technologies revolutionized unconventional natural gas production in the United States (U.S.), particularly in shale formations. Unconventional resources, including shale, tight sands, and coal beds, can be found in more than half of the Lower 48 states; overall production from these resources is forecast to continue growing in the coming decades so that by 2040 half of domestic natural gas production is supplied by unconventional resources. The combined effects of government policies, private sector entrepreneurship, and high natural gas prices spurred advances in horizontal drilling, hydraulic fracturing, and seismic imaging that have opened long-sought energy resources. Unconventional natural gas resources not only make up for declining conventional gas production, but increasing unconventional production is contributing to increased use of gas for power generation, manufacturing, transportation, and residential and commercial heating. These advances swept domestic energy production so fast that between 2009 and 2014, U.S. companies reversed plans to import liquefied natural gas, and many are now proposing exports. Continued increases in production are now most likely to come from the major shale plays, with stable production (as a percentage of total gas production) from tight sands and coal beds. Federal, state, and local governments are re-evaluating statutory and regulatory frameworks, and multiple organizations, separately and in collaboration, are conducting continuing research and development (R&D) to help develop best practices and minimize environmental impacts.

CHAPTER 2 – GREENHOUSE GAS EMISSIONS AND CLIMATE CHANGE

GHG emissions are released by the natural gas supply chain—the extent to which these emissions contribute to climate change has been investigated by government and university researchers. There are five major studies that have accounted for the GHG emissions from upstream natural gas, which include the construction and completion of gas wells, as well as subsequent production, processing, and transport steps. While several studies have been conducted on this topic, these five studies represent the breadth of all-natural gas life cycle work and point to the methane (CH_4) emissions from unconventional well completions and workovers[a] as a key difference between the GHG profiles of conventional and unconventional natural gas. Other key emissions occur during steady-state operations, such as emissions from compressors and pipelines. The assumptions and parameters of the five studies vary, but given

[a] "Workover" is a generic industry term for a variety of remedial actions to stimulate or increase production. As applied here to shale gas wells, it means hydraulic fracturing treatments after the initial drilling and first hydraulic fracturing of the well.

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their uncertainties, four of the five studies conclude that the GHG emissions from a unit of delivered unconventional natural gas are comparable to (if not lower than) those from a unit of conventional natural gas. The fifth study concludes that the high CH_4 emissions from unconventional well completion and a lack of environmental controls at unconventional extraction sites translates to higher GHG emissions from unconventional natural gas than from conventional natural gas.

CHAPTER 3 – AIR QUALITY

GHG emissions from natural gas systems have received significant attention in current literature; however, they are not the only type of air emission from natural gas systems. The two key sources of non-GHG emissions are:

- *Uncaptured Venting*: Releases natural gas, which is a source of volatile organic compound (VOC) emissions.
- *Engine Fuel Combustion*: Produces a wide variety of air emissions, including nitrogen oxides (NO_x), carbon monoxide (CO), sulfur dioxide (SO_2), and particulate matter (PM)

VOCs and NO_x react in the lower atmosphere to produce ground-level ozone, a component of smog that adversely affects human respiratory health. The reaction between VOCs and NO_x is unique because it represents an interaction between two emission sources (in this case, uncaptured venting and fuel combustion). The other emissions from fuel combustion have a variety of human health and ecological impacts. CO affects human health by reducing the oxygen-carrying capacity of blood. SO_2 leads to soil or surface water acidification (via acid rain). PM is linked to poor heart and respiratory health (EPA, 2012; GAO, 2012).

CHAPTER 4 – WATER USE AND QUALITY

In the broadest terms, the literature describes water quality and the treatment and management of wastewaters as the central issue in the eastern states, where water is abundant. To the west, where drier climates can limit the availability of freshwater, and deep underground injection wells for wastewater disposal are more readily available, the central issue is the availability of water for drilling and hydraulic fracturing and the impacts this could have on established users. Drilling and hydraulically fracturing a shale gas well can consume 2–6 million gallons of water; local and seasonal shortages can be an issue, even though water consumption for natural gas production generally represents less than 1 percent of regional water demand. Water quality impacts can result from inadequate management of water and fracturing chemicals on the surface, both before injection and after (as flowback and produced water). Subsurface impacts can result from the migration of fracturing fluids, formation waters, and CH_4 along well bores and through rock fracture networks. Management and disposal of wastewaters increasingly includes efforts to minimize water use and recycling and re-use of fracturing fluids, in addition to treatment and disposal through deep underground injection, with the risk of induced seismicity.

CHAPTER 5 – INDUCED SEISMICITY

Induced seismicity is ground motion (earthquakes) caused by human activities. Earthquakes have been detected in association with oil and gas production, underground injection of waste waters, and possibly with hydraulic fracturing. Hydraulic fracturing involves injecting large volumes of fluids into the ground. These injections are short-lived and are injected at lower pressures, so it is likely that they do not constitute a high risk for induced seismicity that can be felt at the surface. In contrast to hydraulic fracturing, wastewater disposal from oil and gas production, including shale gas production, is typically injected at relatively low pressures into extensive formations that are specifically targeted for their porosities and permeabilities to accept large volumes of fluid. Case studies from several states indicate that deep underground fluid injection can, under certain circumstances, induce seismic activity (NRC, 2012; GWPC, 2013).

CHAPTER 6 – LAND USE AND DEVELOPMENT

Although not as extensively documented as other environmental impacts, like water quality and GHG emissions, land use and development impacts that have been discussed in the literature include property rights and use of public lands, local surface disturbance, cumulative landscape impacts, habitat fragmentation, and traffic, noise, and light. Concerns have been expressed with competing uses for public lands, the cumulative impacts of multiple industries (e.g., timber and tourism), and denial of access to areas with active operations. Surface disturbance involves not only site preparation and well pad construction, but also road, pipeline, and other infrastructure development. The cumulative impacts of surface disturbance can extend over large areas and can also result in habitat fragmentation that impacts both plant and animal species and can result in population declines. Mitigation options include adoption of best practices for site development and restoration, avoidance of sensitive areas, and minimization of disturbed areas. Development on federal land is guided by an extensive set of land use stipulations designed to mitigate these effects. As development and production operations proceed, local residents can be confronted with increased truck traffic, sometimes more than 1,000 truck trips per well, and additional noise and light as construction, development, drilling, and production typically proceed 24 hours per day. Vertical wells require spacing of 40 acres per well, the drill pads from which each horizontal well originates require spacing of 160 acres per well. A single square mile of surface area would require 16 pads for 16 conventional wells, while the same area using horizontal wells would require a single pad for 6–8 wells (NETL, 2009).

CHAPTER 7 – SOCIAL JUSTICE AND NATURAL GAS/LIQUEFIED NATURAL GAS MARKET DEVELOPMENT

TBD

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1 BACKGROUND

Innovations in existing oil and gas exploration and production technologies revolutionized unconventional natural gas production in the United States (U.S.), particularly from shale formations. Unconventional natural gas resources not only make up for declining conventional natural gas production but have also contributed to an increased use of natural gas for power generation, manufacturing, transportation, and residential and commercial heating. Federal, state, and local governments are re-evaluating statutory and regulatory frameworks, and multiple organizations, separately and in collaboration, are continuing to conduct research and development (R&D) to help develop best practices and minimize environmental impacts.

1.1 UNCONVENTIONAL NATURAL GAS RESOURCES

In current usage, three types of reservoirs comprise unconventional natural gas resources: shale gas, "tight" (low permeability) sandstones, and coalbed methane (CBM). A fourth type of reservoir—methane hydrates—is also used (DOE, 2011). The dispersed nature of the resources in these reservoirs is one of the reasons for calling them unconventional. The gas (and oil) in these reservoirs is less concentrated than natural gas in conventional reservoirs where the gas has accumulated in geologic traps. Lower permeabilities make unconventional natural gas more difficult to extract. Implications of low permeability include the need for greater scales of operations and either more, or directional, wells to contact the larger areas of production in target formations.

As its name suggests, shale gas is found in shale which is a sedimentary rock consisting of mainly clay and clay-sized particles. The crystalline structures of clay minerals form in thin, parallel sheets, somewhat like the skin of an onion. Small flakes of clay carried by streams and rivers settle in low-energy geologic environments like tidal flats and in deep ocean basins where they fall flat and parallel to one another. As these sediments are covered and buried, they are compacted into thin layers with low permeabilities. Like pages in a book, these layers restrict fluid flow, especially vertically across the layers. At the same time, microscopic bits of organic matter, plant and animal debris that were deposited with the clay flakes, decay, and under the heat and pressure of deep burial, form natural gas and liquid hydrocarbons. The low permeability traps the gas and hydrocarbons in the shale, so the shale must be fractured to increase the permeability and allow the gas to flow into wells (NETL, 2009a).

Organic-rich shale formations are widespread across most parts of the world because shale is found in all sedimentary basins and can make up to 80 percent of the sediments in a basin. In many cases, enough is already known about shale formations that little precise exploration is needed as most operators are already aware of the shale gas reserves that exist at a given location. At the same time, operators may not be able to estimate the technically and economically recoverable resources at a reserve until wells have been drilled and tested. Shale formations each have unique geologic characteristics, as such within each formation there are differences that create "sweet spots" for production.

Dozens of gas-bearing shale formations are in sedimentary basins across the United States. Some areas like the Appalachian Basin, the Michigan Basin, and the Illinois Basin have long

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"Unconventional natural gas resources primarily comprise three types of reservoirs: shale gas, "tight" (low permeability) sandstones, and coalbed methane (CBM) histories of natural gas production. With improvements in unconventional technologies such as horizontal drilling and hydraulic fracturing, plays like the Barnett, Fayetteville, Haynesville, Marcellus, and Woodford have witnessed growth in the number of unconventional wells being drilled in addition to existing conventional wells.

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"Tight gas" reservoirs were defined in the 1970s by the federal government as having a permeability to gas flow of less than 0.1 millidarcy (a unit to measure the permeability of rock to determine which gas wells would be eligible for tax credits to encourage production). They are not necessarily deposited differently than conventional sandstone reservoirs but may have lower permeabilities due to more intensive cementing by mineral precipitates. A more technical definition might be "a reservoir that cannot be produced at economic flow rates nor recover economic volumes of natural gas unless the well is stimulated by a large hydraulic fracture treatment, by a horizontal wellbore, or by use of multilateral wellbores" (Holditch, 2006).

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Like conventional sandstone gas reservoirs, tight gas sands form as gas from organic-rich source rocks (like shales) migrates into the sands and is trapped. Like shale gas formations, the low permeabilities mean that tight sand formations must be stimulated to produce commercial quantities of gas. However, once drilled and stimulated, tight gas sand reservoirs tend to have better production factors than shale reservoirs (IEA, 2012). Tight gas sand plays are less extensive than shale plays, with nearly half of the estimated domestic tight sand reserves being located in the Green River, Piceance, and Uinta Basins in Colorado and Utah, and the East Texas Basin (DOE, 2011).

1.2 Technology Advances and Adaptation

Wang and Krupnick (2013) recount the history of the economic, policy, and technology developments that led to large-scale U.S. shale gas production. Their explanation (intended for international stakeholders) of the advent of the U.S. shale gas boom offers a case study of the interactions among government policies, private sector entrepreneurship, technology innovations, land and mineral rights ownership structures, and high gas prices that helped create the boom. In the late-1970s, the United States faced natural gas supply shortages, high prices, and declining prospects for additional conventional natural gas production. The federal government recognized that private corporations lacked incentives to make large-scale, high-risk research and development (R&D) investments for the industry.

To compensate for the difficulty in protecting and patenting new technologies in the oil and gas industry, the federal government funded R&D programs and provided tax credits to promote the development of unconventional resources. Shale gas production from the Barnett Shale region of Texas increased from the early 1980s to the late 1990s, after Mitchell Energy invested a large amount of money in the area. The Barnett Shale was not included in early assessments of potential natural gas resources prior to this time. As a nation, the United States offered favorable geology, water availability, private land and mineral ownership rights, structured energy markets, and existing infrastructure to translate the success in the Barnett into greatly increased natural gas production from other shale plays (Wang and Krupnick, 2013).

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Natural gas production from unconventional resources became economically viable due to advances in development and production technologies, leading to large-scale utilization of resources that had historically been uneconomic to extract (Jackson et al., 2011). Advances in horizontal drilling equipment and hydraulic fracturing techniques allowed greater access to unconventional reservoirs. A key innovation for shale formations was the addition of very fine grains of sand, known as proppants, which to held the fractures open allowing trapped gas to flow into a well (CRS, 2009). Jackson et al. (2011) estimated that a single horizontal well is two to three times more productive than a single vertical well and can reach resources two miles away from the well pad.

However, neither of these technologies (horizontal drilling equipment and hydraulic fracturing) are new. Horizontal drilling has been used since the 1930s, originally to drill from land into formations under the seabed and with advancements in the early 1980s became more commercially viable. Hydraulic fracturing was developed in the 1950s and has been applied to shale gas wells since the mid-1980s (NETL, 2009a). The Interstate Oil & Gas Compact Commission estimates that 90 percent of oil and gas wells in the U.S. use hydraulic fracturing(Jackson et al., 2011). Estimates from industry data indicate that hydraulic fracturing has been used in more than a million wells in all 33 states that produce oil and gas (The Horinko Group, 2012). Exhibit 1-1 illustrates these processes in a representative shale gas well.

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Exhibit 1-1. Horizontal drilling, hydraulic fracturing, and well construction

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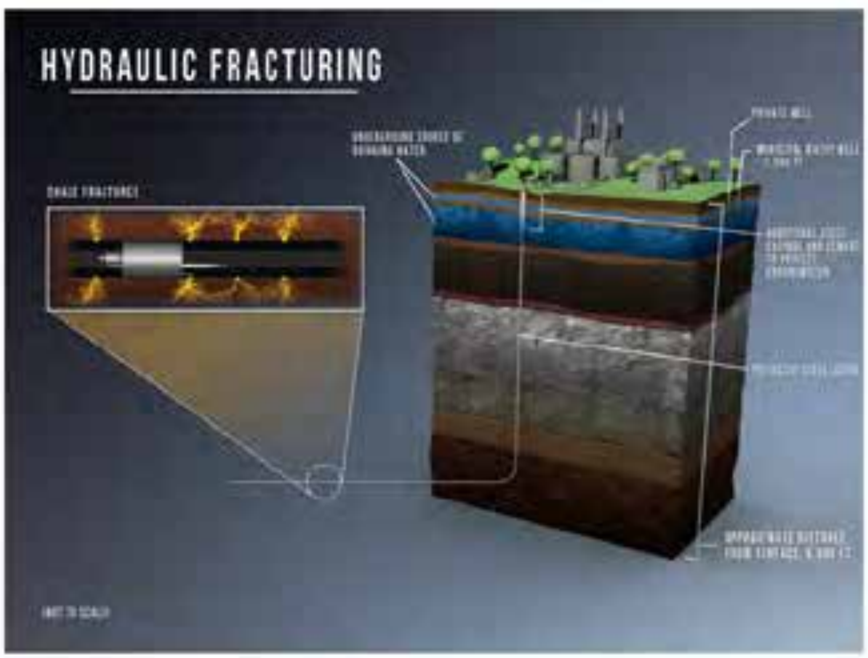

Fracturing fluids used for hydraulic fracturing commonly consist of mostly water and sand along with other chemicals and additives (NETL, 2009a). The specific additives, and the proportion of each, depend on the formation that is being fractured. These additives function as friction reducers, biocides, oxygen (O_2) scavengers, stabilizers, and acids, all of which are necessary to optimize shale gas production (NETL, 2009a). The composition of these fluids and the purposes of the additives are described in more detail in Chapter 4 – Water Use and Quality.

1.3 Unconventional Reserves and Production

There remains significant uncertainty in the estimates of the total technically recoverable natural gas reserves located in the Lower 48 states. Estimates range widely from 2,417.6 trillion cubic feet (Tcf) in the U.S. Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2022 [Early Release], to 2,650 Tcf in the Colorado School of Mines' Potential Gas Committee (EIA, 2022). Differences in these estimates are due to difference combinations of data and different assumptions about policies, technologies, future demand, prices, and macroeconomic conditions being used. For example, some states may continue to limit access to these resources. On the other hand, continuing technological advancements could increase recovery rates and lower production costs (BPC, 2013).

The Government Accountability Office (GAO) (2012a) analyzed EIA data and concluded that actual shale gas production grew from 1.6 Tcf to 7.2 Tcf between 2007 and 2011, over 75 percent of which came from the Barnett, Fayetteville, Marcellus, and Haynesville Shale plays. With increasing development, EIA (2022) forecasts a 15 percent net increase in natural gas production between 2022 and 2050 in response to increased development of unconventional resources including shale gas, tight gas, and CBM. EIA also estimates that the largest contributor to this overall growth will be production from shale gas. EIA estimates that in 2022, U.S. dry natural gas production from shale formations was about 28.5 Tcf and equal to about 80 percent of total U.S. dry natural gas production in 2022. Tight gas and CBM production will each increase by about 25 percent but their contributions to total production will decrease slightly, overshadowed by shale. Growth in CBM production is not expected to materialize until after 2035, when prices and demand levels rise enough to promote further drilling.

1.4 Best Practices

In 2011, the Secretary of Energy formed a subcommittee of the Secretary of Energy Advisory Board (SEAB) (2011a) to make recommendations to address the safety and environmental performance of shale gas production. In August 2011, the Shale Gas Production Subcommittee released its first 90-day report presenting 20 recommendations intended to reduce the environmental impacts of shale gas production. (SEAB 2011a) The Subcommittee stressed the importance of continuous improvement based on best practices and tied to measurement and disclosure. The recommendations were made in ten areas (SEAB, 2011a):

- Improve public information about shale gas operations: create a portal to share public information, including data from state and federal regulators.
- Improve communication among state and federal regulators: continue annual support to State Review of Oil and Natural Gas Environmental Regulations (STRONGER) and the Groundwater Protection Council (GWPC).

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- Improve air quality: take measures to reduce emissions of air pollutants, ozone precursors, and CH4methane.
- Protect water quality: adopt a systems approach to water management based on consistent measurement and public disclosure.
- Disclose fracturing fluid compositions: accelerate progress in disclosure of all chemicals used in fracturing fluids.
- Reduce use of diesel fuel: reduce use of diesel engines for surface power and replace with natural gas or electric engines where possible.
- Manage short-term and cumulative impacts to communities, land use, wildlife, and ecologies: pay greater attention to combined impacts from drilling, production, and delivery activities and plan for shale development impacts on a regional scale.
- Organize for best practice: create an industry organization for continuous improvement of best practice.
- Identify research and development needs: significantly improve efficiency of shale gas production through technical advances.

1.5 U.S. Statutory and Regulatory Framework

Multiple federal agencies have authority for unconventional natural gas development and production. The Environmental Protection Agency (EPA) regulates deep underground injection and disposal of wastewater and liquids under the Safe Drinking Water Act (SDWA), as well as air emissions under the Clean Air Act. The Occupational Safety and Health Administration is responsible for quantifying standards for application in the oil and gas industry. On public lands, federal agencies are responsible for the enforcement of regulations that apply to unconventional gas wells. These agencies include EPA, the Department of the Interior (DOI) Bureau of Land Management (BLM), the National Park Service (NPS), the Occupational Safety and Health Administration, and the U.S. Forest Service (USFS). The BLM is responsible for protecting the environment on its lands during all oil and gas activities. The USFS is responsible for managing development on federally owned lands along with the BLM (NETL, 2009a). If any types of oil and gas activities are proposed to take place within national park boundaries, the NPS may be able to apply regulations to protect park resources and visitor values, but the applicability of those regulations depends on each case.

Exhibit 1-2 gives some examples of the applicability of federal regulations to unconventional natural gas development (CRS, 2009; NETL, 2009a).

Exhibit 1-2. Selected federal regulations that apply to unconventional oil and gas development

Regulation	Applicability
Clean Air Act	Places requirements on air emissions from sources of emissions at well sites. Addresses compliance with existing and new air regulations, often delegated to local and state agencies. Generally, there is no distinction made between conventional and unconventional wells under the Clean Air Act.

Regulation	Applicability
Comprehensive Environmental Response, Compensation, and Liability Act	Only applies if hazardous substances besides crude oil or natural gas are released in quantities that require reporting. Natural gas releases do not require notification under the Comprehensive Environmental Response, Compensation, and Liability Act, but other hazardous substances may be released in reportable quantities during natural gas production.
Clean Water Act	Pollutant limits on produced water discharge under the National Pollutant Discharge Elimination System; storm-water runoff containing sediments that would cause a water-quality violation to require permits under Clean Water Act decisions. Beneficial uses of surface waters are protected under Section 303.
Emergency Planning and Community Right-to-Know Act	Facilities storing hazardous chemicals above the threshold must report such and provide a Material Safety Data Sheet to officials and fire departments.
Endangered Species Act	Section 7 prohibits federal agencies from taking any action that is likely to jeopardize the continued existence of any endangered or threatened species (listed species) or result in the destruction or adverse modification of such species designated critical habitat. Section 9 prohibits the taking of a listed species. Under Section 10, the Fish and Wildlife Service and National Marine Fisheries Service may issue a permit, accompanied by an approved habitat conservation plan that allows for the incidental, non-purposeful "take" of a listed species under their jurisdiction.
National Environmental Policy Act	Requires analysis of potential environmental impacts of proposed federal actions, such as approvals for exploration and production on federal lands.
Oil Pollution Act	Spill prevention requirements, reporting obligations, and response planning (measures that will be implemented in the case of release of oil or other hazardous substances).
Resource Conservation and Recovery Act	Subtitle D concerns non-hazardous solid wastes. The Solid Waste Disposal Act exempts many wastes produced during the development of natural gas resources, including drilling fluids and produced water. EPA has determined that other federal and state regulations are more effective at protecting health and the environment.
Safe Drinking Water Act	Underground Injection Control (UIC) program preventing the injection of liquid waste into underground drinking water sources. Fluids other than diesel fuel do not require a UIC permit. The UIC program gives requirements for siting, construction, operation, closure, and financial responsibility. Forty states control their own UIC programs.

The Western Interstate Energy Board described the importance of unconventional gas reservoirs, technical aspects of hydraulic fracturing, regulation, and potential environmental impacts (McAllister, 2012). Although there are several other federal regulations that the unconventional gas industry must comply with, the SDWA is "of greatest importance to the sector" (McAllister, 2012). While state laws and regulations can vary, stringency has increased in recent years. State agencies typically oversee the well itself while local governments are generally responsible for upstream activities, such as road access to drilling sites. The potential environmental impacts include water and air quality, as well as seismic activity and noise (McAllister, 2012).

In response to concerns raised by the rapid growth in the use of fracturing, the potential impacts to groundwater and drinking water resources, and calls for increased government oversight, the Congressional Research Service (CRS) reviewed past and proposed treatment of hydraulic fracturing under the SDWA (Tiemann and Vann, 2012). The SDWA is the principal federal statute for regulating the underground injection of fluids. The Energy Policy Act of 2005 excluded hydraulic fracturing fluids and proppants (except diesel fuel) from the definition of "underground injection." Therefore, EPA has no SDWA authority to regulate hydraulic fracturing unless diesel fuel is included in the waste fluids to be injected underground.

Two federal agencies have recently taken regulatory actions related to shale gas production. EPA has applied new source performance standards and expanded mandatory greenhouse gas (GHG) reporting to include unconventional natural gas production. The BLM has proposed regulations for hydraulic fracturing on public and Indian lands.

In 2009, EPA promulgated the Mandatory Reporting of Greenhouse Gases Rule at Title 40 Code of Federal Regulations (CFR) Part 98 requiring the reporting of GHG data from large U.S. sources. This rule also requires suppliers to collect timely and accurate data to inform future policy decisions (EPA, 2009). The petroleum and natural gas industry is covered under Subpart W, and unconventional natural gas production is included under provisions for onshore production, natural gas processing, natural gas transmission, and liquefied natural gas (LNG) storage and import/export. Annual carbon dioxide (CO_2), $CH_{4,}$ and nitrogen oxide (NO_x) emissions must be reported separately for each of these segments (EPA, 2012a).

On April 17, 2012, EPA promulgated a final rule at 40 CFR Parts 60 and 63, entitled "Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews," under the Clean Air Act provisions for new source performance standards (NSPS) (EPA, 2012b). EPA expects the rule to reduce volatile organic compound (VOC) emissions by nearly 95 percent, mainly through "green" or "reduced emissions" completions that capture natural gas that currently escapes to the air. Reductions in VOC emissions will help reduce ground-level ozone in natural gas production areas and help protect against potential cancer risks from several air toxins, including benzene. Green completions also reduce CH_4 emissions. EPA estimates the combined rules will yield a cost savings of $11–19 million (MM) in 2015, because of the value of natural gas and condensate that will be recovered and sold, and the value of the climate co-benefits at $440 MM annually by 2015 (EPA, 2012b).

The BLM oversees more than 750 MM acres of federal and Indian mineral estates nation-wide, and on May 11, 2012, published a proposed rule to regulate hydraulic fracturing on public land and Indian land entitled "Oil and Gas Well Stimulation, Including Hydraulic Fracturing, on Federal and Indian Lands" at 43 CFR Part 3160. The rule would require public disclosure of the chemicals used in hydraulic fracturing on public land and Indian land, strengthen regulations related to well-bore integrity, and address issues related to flowback water (fluids used in hydraulic fracturing that are recovered from the well, which must then be disposed of) (BLM, 2012).

The BLM (2013) used comments on its proposed draft rule to make improvements and on May 24, 2013, published a supplemental notice seeking additional comments. The updated draft included provisions to ensure the protection of usable water zones through an expanded set of cement evaluation tools, including a variety of logging methods, seismograms, and other techniques. Detailed guidance on the handling of trade secret claims modeled on State of Colorado procedures was added to address concerns that industry had voiced on the disclosure of fluid constituents that were proprietary. The BLM (2013) also sought opportunities to reduce costs and increase efficiency through coordination with individual states and tribes.

States have the power to implement their own requirements and regulations for unconventional gas drilling under federal oversight. All states that produce gas have at least one agency to permit drilling wells, and many federal regulations for oil and gas production allow states to implement their own programs if these programs have been approved by the appropriate federal agencies (NETL, 2009a). While state requirements differ, any requirements set forth in federal regulations must be met at a minimum—in other words, state requirements can be more stringent than federal regulations, but they cannot be less stringent than federal regulations.

The National Energy Technology Laboratory (NETL) (2009b) and GWPC (2013) evaluated the state regulatory programs for oil and natural gas production for their applicability and adequacy for protecting water resources. NETL reviewed regulations for permitting, well construction, hydraulic fracturing, temporary abandonment, well plugging, tanks, pits, and waste handling and spills. The report presented five key messages:

1. State oil and gas regulations are adequately designed to directly protect water resources through the application of specific programmatic elements such as permitting, well construction, well plugging, and temporary abandonment requirements.
2. Experience suggests that state oil and gas regulations related to well construction are designed to be protective of groundwater resources relative to the potential effects of hydraulic fracturing. However, development of best management practices related to hydraulic fracturing would assist states and operators in insuring continued safety of the practice, especially as it relates to hydraulic fracturing of zones near groundwater, as determined by the regulatory authority.
3. Many states divide jurisdiction over certain elements of oil and gas regulation between the oil and gas agency and other state water protection agencies. This is particularly evident in the areas of waste handling and spill management.
4. The state review process conducted by the national non-profit organization STRONGER (2013) is an effective tool in assessing the capability of state programs to manage exploration and production waste and in measuring program improvement over time.
5. The implementation and advancement of electronic data management systems has enhanced regulatory capacity and focus. However, the inclusion of more environmental data is needed, as well as further work in the areas of paper-to-digital data conversion.

DOE (2011) concluded that oil and gas field activities are best regulated and managed at the state level where regional and local conditions are better understood. Effective regulatory programs use a set of tools that include formal and informal guidance, field rules, and best management practices, in addition to the regulations themselves. (DOE, 2011).

The National Conference of State Legislatures (Pless, 2012) introduces domestic natural gas production, describes legislative involvement at the state level, and summarizes the development of state legislation (Pless, 2012). Pless (2012) calls attention to public health and environmental impacts including protection of surface water, water withdrawals, air quality, habitat, and seismic activity. State policy actions fall into four categories:

1. Increasing Transparency: Disclosure of fracturing fluid chemicals and additives.
2. Generating Revenue through Taxes and Fees: Severance taxes for resources “severed” from the earth can provide significant revenue streams and impact fees can benefit local communities.
3. Water Quality Protection: Leak and spill prevention, wastewater transportation, waste treatment and disposal regulations, and well location restrictions help protect water quality.
4. Monitoring to Improve Knowledge Base: Water withdrawal and quality monitoring can protect water resources. Some states have instituted moratoria on drilling until more is known about the impacts, including New Jersey and Vermont. Other states, such as Illinois, Michigan, New York, North Carolina, Ohio, and Pennsylvania, have legislation pending various moratoria. New Jersey’s moratorium was for one year, while Vermont’s completely prohibits hydraulic fracturing within the state. Pending legislation would provide for impact studies and assessments, prohibit hydraulic fracturing, or establish moratoria pending the outcome of other studies.

Another analysis was completed by Resources for the Future’s (RFF) Center for Energy Economics and Policy (2012) website, which looked at requirements in 31 U.S. states that either have shale gas production development or could have some soon. This review examined similar items related to shale gas development, organized into five general categories (RFF, 2012):

- Site development and preparation
- Well drilling and production
- Flowback and wastewater storage and disposal
- Well plugging and abandonment
- Well inspection and enforcement

In June 2013, RFF (2013) released a full report containing an analysis of state regulations and requirements pertaining to shale gas development, which synthesized much of the information available on the website tool into an actual document. This analysis determined that there is little similarity in the way states are regulating the various categories of shale gas development. The report did not suggest that one method was better than another, but instead identified the differences from state to state (RFF, 2013).

1.6 FEDERAL RESEARCH AND DEVELOPMENT PROGRAMS

In 2011, the Department of Energy (DOE) delineated the technical challenges for unconventional gas development as part of the R&D program managed by NETL under the Energy Policy Act of 2005. The technical challenges for tight gas include a need for an improved understanding of the geologic environments and the environmental and safety risks, and the development of improved technologies for drilling, sensors, development, and production. For CBM, the challenges include a need for an improved understanding of the resource, water management, and improved drilling and production, including multi-seam completions. Shale gas has many of the same challenges, including improving understanding of the risks, gaining better understanding of the geologic environments, water management, and improved drilling, development, and production technologies (DOE, 2011).

DOE's shale gas program brings together federal and state agencies, industry, academia, non-governmental organizations, and national laboratories to develop oil and gas technologies under Section 999 of the Energy Policy Act of 2005. The work focuses on safety, environmental sustainability, and calculating the risks of oil and gas exploration and production undertakings. DOE has funded several technology investigations through NETL that deal with produced water management. DOE has been developing a tool that can be used to help the operators of oil and gas operations to meet challenges presented in reducing, reusing, and disposing of produced water from wells (DOE, 2013a). Fact sheets have been produced for various practices for produced water during the operation of wells, including the following (NETL, 2013):

- *Water Minimization*: Reducing the volume of produced water both entering the well and flowback at the surface
- *Water Recycling and Reus*e: Investigating alternative uses for produced water, such as underground injection, use in agricultural settings, and use in industrial settings
- *Water Treatment and Disposa*l: Discovering methods to remove impurities from the produced water and permanently dispose of the produced water

NETL is also conducting research to improve the assessment of air quality impacts in the field with a mobile air monitoring laboratory, and then using these data to model atmospheric chemistry and chemical transport to better understand local and regional impacts (DOE, 2013b). Goals of this research include the following:

- *Document Environmental Changes*: Distinguishing the changes that occur during each phase of shale gas production (e.g., site construction, drilling, well completion, early production, and production after site remediation)
- *Develop Technology and Management Practice*s: Mitigating undesired environmental changes
- *Develop Monitoring Technique*s: Increasing sensitivity and speed while decreasing costs

Projects include efforts to determine air quality, detect fugitive emissions, detect unwanted migration of production fluids, locate existing wells and pipelines, and document changes in avian populations (DOE, 2013b). Additionally, DOE is collaborating with other agencies on EPA's hydraulic fracturing study (EPA, 2012c).

EPA (2013) cooperates with key stakeholders to make sure that unconventional gas resources are managed responsibly and do not inflict unnecessary damage on the environment and on the public. In 2010, at the request of Congress, EPA initiated a study to better understand any potential impacts of hydraulic fracturing on drinking water and groundwater. The overall purpose of the study is to elucidate the relationship, if any, between hydraulic fracturing and drinking water resources, and to identify the driving factors that affect the severity and frequency of any impacts (EPA, 2011). In their plan, EPA designed their study to provide decision-makers and the public with answers to five fundamental questions associated with the hydraulic fracturing water life cycle:

- *Water Acquisition*: What are the potential impacts of large volume water withdrawals from ground and surface waters on drinking water resources?
- *Chemical Mixin*g: What are the possible impacts of surface spills on or near well pads of hydraulic fracturing fluids on drinking water resources?
- *Well Injectio*n: What are the possible impacts of the injection and fracturing process on drinking water resources?
- *Flowback and Produced Wate*r: What are the possible impacts of surface spills on or near well pads of flowback and produced water on drinking water resources?
- *Wastewater Treatment and Waste Disposa*l: What are the possible impacts of inadequate treatment of hydraulic fracturing wastewaters on drinking water resources?

In December 2012, EPA (2012c) published the first progress report for their study describing 18 research projects that are underway, including analyses of existing data, scenario evaluations, laboratory studies, toxicity assessments, and case studies.

The U.S. Geological Survey (USGS) operates both the Energy Resources Program (ERP) and the John Wesley Powell Center for Analysis and Synthesis. The ERP performs oil and gas resources assessments for the United States as well as the world, synthesizing information used to develop energy policies and resource management plans, as well as researching hydraulic fracturing and produced water (USGS, 2010; USGS, 2013a). The USGS has developed a screening process that can be used to determine whether unconventional gas resources exist in each location. The process of hydraulic fracturing and the resulting produced water and other fluids play a large role in the exploration and development of unconventional resources (USGS, 2010).

Current working groups of the Powell Center for Analysis and Strategy include one assessing the potential effect of developing shale gas resources on surface and groundwater and another investigating seismicity resulting from the injection of fluids (USGS, 2013b). The water quality investigation includes several objectives (USGS, 2012):

- *Hydraulic Fracturing*: Gain better understanding of the hydraulic fracturing process in the United States.

- *Water Quality*: Investigate surface water and groundwater quality near unconventional gas production, possible water quality changes due to production operations, and gather baseline water quality data near the production operations.
- *Data Gaps*: Determine areas where further investigation is necessary for evaluation.
- *Future Work*: Ascertain future work that can help increase understanding of how unconventional gas production effects water quality.

1.7 REFERENCES

Commented [HSAJ25]: In future iterations, please continue to make sure all in-text citations are included in the reference list and all references in the list are included as in-text citations. Same comment applies for each chapter.

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2 GREENHOUSE GAS EMISSIONS AND CLIMATE CHANGE

There are several major studies that detail potential GHG emissions from upstream natural gas.[b] The assumptions and parameters of these studies vary, but the majority conclude the GHG emissions from one unit of delivered unconventional natural gas are comparable to (if not lower than) the GHG emissions produced from one unit of conventional natural gas. Studies suggest, in the case of LNG, liquefaction accounts for a significant portion of total associated GHG emissions given the significant energy demand involved in the process.

To account for all sources of GHG emissions in the production of unconventional natural gas, and to evaluate their relative contributions and mitigation opportunities a systems-level perspective is both necessary and prefered. Life cycle analysis (LCA) is one type of systems approach available to account for sources of GHG emissions as LCA specifically considers the material and energy flows of a system from cradle to grave, where the cradle is the extraction of resources from the earth, and the grave is the final use and disposition of all products. NETL has used LCA to calculate the environmental impacts of natural gas production and use for electric power generation for nearly a decade. Their work has been documented in a series of reports produced between 2010 and 2019.[c] Together, these reports provide in-depth assessments of the potential GHG emissions resultant from unconventional natural gas production in the United States.

The GHG results in the NETL 2019 report encompass five stages in the natural gas supply chain, which are visualized in Exhibit 2-1 (NETL, 2019):

1. **Production**: Sources of emissions include the gas vented from pneumatically-controlled devices and fugitive emissions from flanges, connectors, open-ended lines, and valves. When vapor recovery units are feasible, vented gas is captured and flared; otherwise, vented gas is released to the atmosphere. Production operations also include the combustion of natural gas and diesel in compressors and other equipment.
2. **Gathering and Boosting**: Natural gas gathering and boosting networks receive natural gas from multiple wells and transport it to multiple facilities. Gathering and boosting sites include acid gas removal, dehydration, compressors operations, pneumatic devices, and pumps.
3. **Processing**: A natural gas processing facility removes impurities from natural gas, which improves its heating value and prepares it for pipeline transmission. Natural gas processing facilities include acid gas removal, dehydration, hydrocarbon liquids removal, and compression operations.
4. **Transmission Stations, Storage Facilities, and Transmission Pipelines**: A natural gas transmission system is a network of large pipelines that transport natural gas from processing facilities to the city gate (the point at which natural gas can be consumed by large-scale consumers or transferred to local distribution companies). Transmission

[b] Upstream natural gas includes the construction and completion of gas wells, as well as subsequent production, processing, and transport steps.

[c] The GHG results in the NETL (2019) report supersede the GHG results in the previous NETL reports.

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stations are located along natural gas transmission pipelines and use compressors to boost the pressure of the natural gas.

5. **Distribution**: Natural gas distribution networks transport natural gas from the city gate to commercial, residential, and some industrial consumers. This analysis uses the distribution portion of the supply chain only for the upstream functional unit; distribution is not necessary for the functional unit of electricity in which natural gas power plants receive natural gas directly from transmission pipelines.

Exhibit 2-1. Supply chain stages that compose the overall LCA boundary

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The flexible, consistent framework of NETL's LCA model allows different natural gas sources to be compared on a common basis. In the NETL 2019 report, five types of extraction technologies are considered:

1. **Conventional natural gas** is extracted via vertical wells in high permeability formations that do not require stimulation technologies for primary production.
2. **Coalbed methane** is extracted from coal seams and requires the removal of naturally occurring water from the seam before natural gas wells are productive.
3. **Shale gas** is extracted from low permeability formations and requires hydraulic fracturing and horizontal drilling.
4. **Tight gas** is extracted from non-shale, low permeability formations and requires hydraulic fracturing and directional drilling.
5. **Associated gas** is found with petroleum (either dissolved in oil or in a gas cap in a petroleum formation) and is produced by oil wells.

Exhibit 2-2 shows the 2016 production share for the 30 onshore, offshore, and associated natural gas scenarios (NETL, 2019). These production shares are based on filtered Drillinginfo Desktop production data. Exhibit 2-3 extrapolates the production shares of 14 onshore regions to represent all onshore production (which is 79.6 percent of total U.S. production) (NETL, 2019). The remaining balance of U.S. production comes from offshore natural gas wells (4.3 percent) and associated gas (16.1 percent).

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Exhibit 2-2. Natural gas production shares by well type and geography

Geography	Well Type						
	Conventional	Shale	Tight	CBM	Offshore	Associated	Total
Onshore Production							
Anadarko	2.2%	2.6%	1.7%				6.5%
Appalachian		29.0%					29.0%
Arkla	0.4%	4.7%	1.4%				6.6%
Arkoma	0.3%	0.9%					1.2%
East Texas	1.6%	1.3%	1.3%				4.2%
Fort Worth Syncline		1.8%	0.0%				1.8%
Green River	1.6%		3.9%				5.5%
Gulf Coast	0.8%	6.6%	1.3%				8.7%
Permian	2.3%	5.3%					7.6%
Piceance			0.3%				0.3%
San Juan	1.4%			1.9%			3.3%
South Oklahoma		1.0%					1.0%
Strawn		3.2%					3.2%
Uinta	0.5%		0.8%				1.3%
*Subtotal Onshore**	*11.0%*	*58.0%*	*10.6%*	*1.9%*			*79.6%*
Offshore Production							
Offshore Gulf of					4.2%		4.2%
Offshore Alaska					0.1%		0.1%
Subtotal Offshore					*4.3%*		*4.3%*
Associated Gas							
United States						16.1%	16.1%
Total							
*Total**	*11.0%*	*58.0%*	*10.6%*	*1.9%*	*4.3%*	*16.1%*	*100%*

* Due to rounding errors, the subtotals for onshore wells and the totals for all well types do not exactly match the sums of values reported for individual well types.

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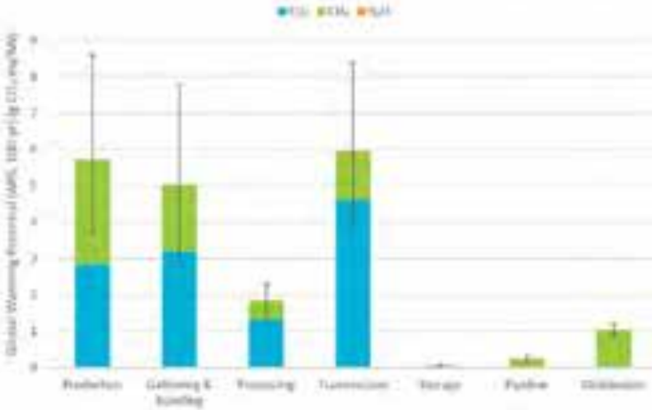
2.1 A Life Cycle Perspective

Exhibit 2-3 shows the upstream GHG emissions from the different parts of the supply chain. The blue bars represent carbon dioxide (CO_2) emissions, the green bars represent methane (CH_4) emissions, and the orange bars represent nitrous oxide (N_2O) emissions. The vertical black lines in Exhibit 2-3 represent the error bars in this analysis. These emissions are expressed in terms of 100-year global warming potential (GWP) as recommended by the Intergovernmental Panel on Climate Change (IPCC) (2023). GWPs normalize GHG species to a common basis. For example, the 2013 version of IPCC's GWPs show that the radiative forcing of CH_4 is 28 times greater than CO_2 over a 100-year period; to arrive at a common basis, the life cycle results for CH_4 are multiplied by 28 so CO_2 and CH_4 can be expressed in common units—carbon dioxide equivalents (CO_2e).

Exhibit 2-3. Life cycle GHG emissions for the U.S. natural gas supply chain



In addition to its characterization of domestic upstream natural gas, NETL also developed life cycle data for exported LNG, including the GHG emissions from liquefaction, transport, regasification, and combustion for electricity generation (NETL, 2019). The burdens of liquefaction, ocean transport, and regasification significantly increase the upstream burdens of LNG relative to natural gas that is not liquefied.

The life cycle GHG emissions from the U.S. natural gas supply chain are 19.9 grams (g) CO_2e/megajoule (MJ) (with a 95 percent mean confidence interval of 13.1–28.7 g CO_2e/MJ) (NETL, 2019). The top contributors to CO_2 and CH_4 emissions are combustion exhaust and other venting from compressor systems. Compressor systems are prevalent in most supply chain stages, so compressor emissions are key emission drivers for life cycle emissions. Exhibit 2-4 shows life cycle GHG emissions from different sectors of the U.S. natural gas supply chain (NETL, 2019). Emission rates are highly variable across the entire supply chain. The national average CH_4 emission rate is 1.24 percent, with a 95 percent confidence interval ranging 0.84–1.76.

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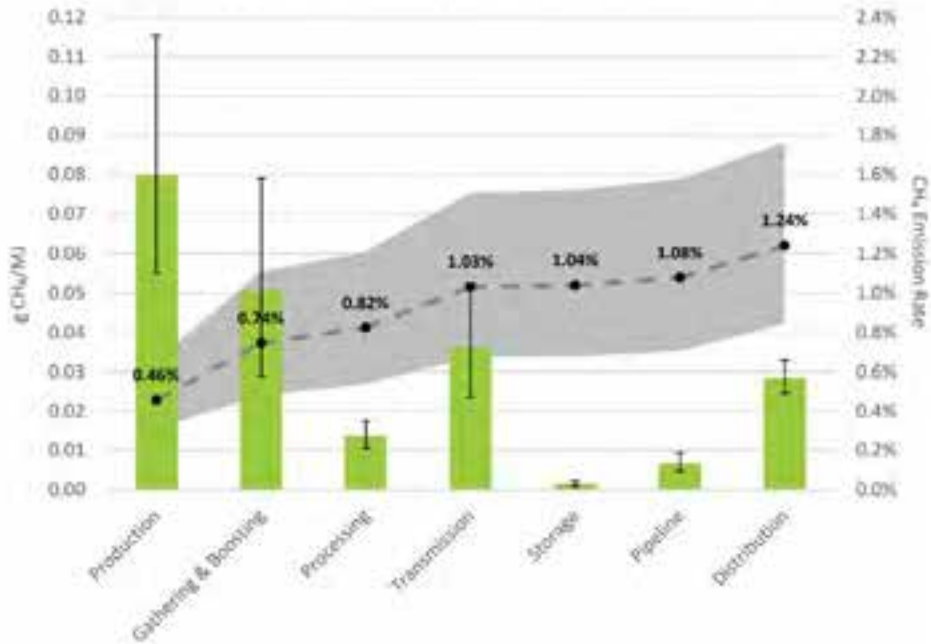
Exhibit 2-4. Life cycle CH_4 emissions from the U.S. natural gas supply chain



2.2 Key Contributors to Natural Gas GHG Emissions

The key drivers of GHG results for the entire natural gas value chain are illustrated in Exhibit 2-5 (NETL, 2019). These boundaries are also referred to as "cradle-to-gate," where the cradle is the extraction of natural gas from nature and the gate is the delivery of natural gas to a power plant via a natural gas transmission pipeline. These results use the same boundaries as Exhibit 2-1, but show more detail on the contribution of specific unit processes in the supply chain.

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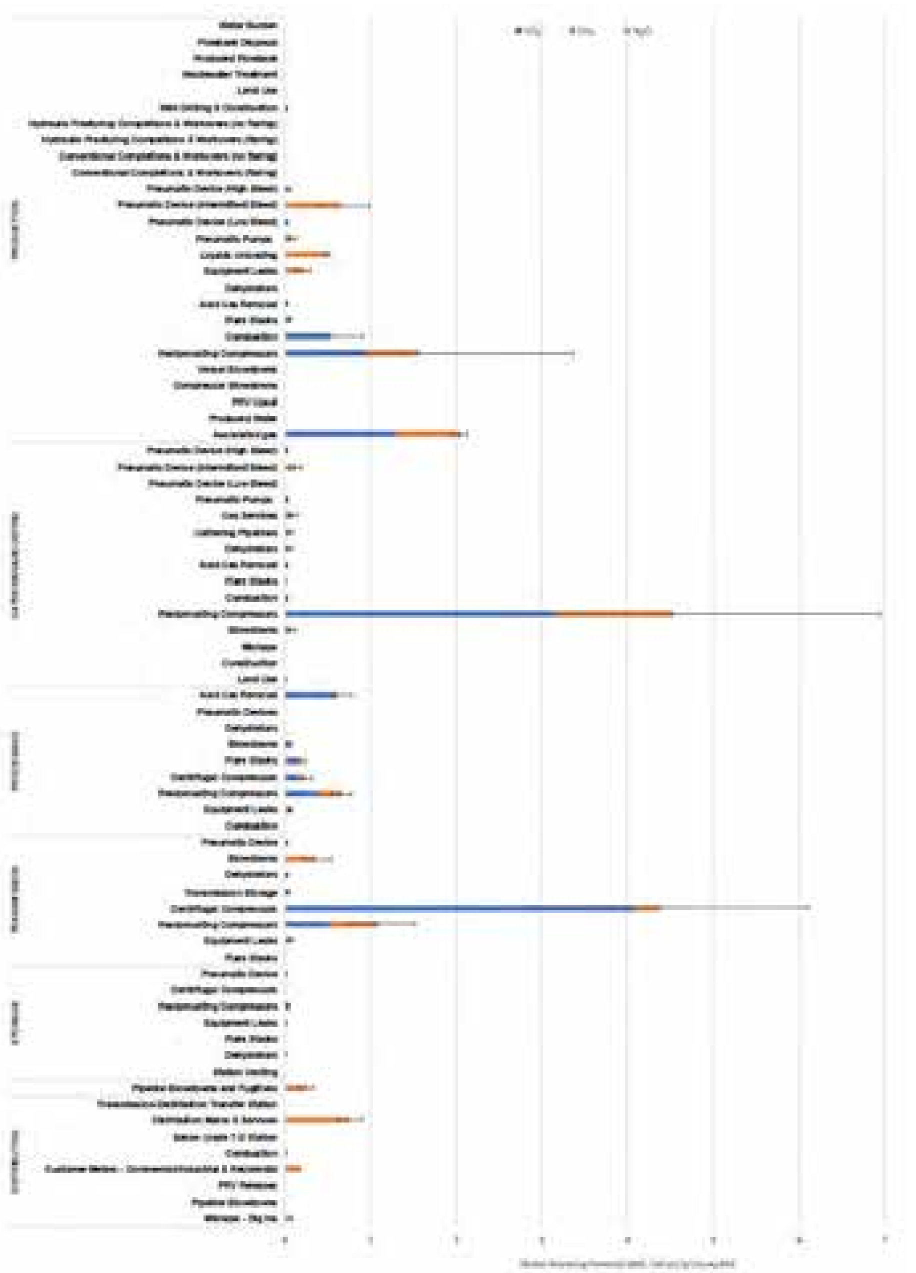
Exhibit 2-5. Detailed GHG emission sources for the U.S. natural gas supply chain

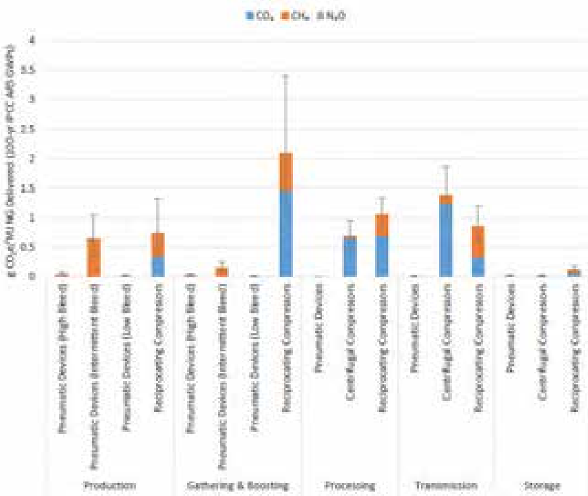


Pneumatic devices and compression systems are two emission's sources representing a significant portion of the life cycle natural gas GHG emissions of the natural gas supply chain (NETL, 2019). Pneumatic devices are used to operate level controllers, valves, and other equipment at natural gas facilities. According to the EPA's Greenhouse Gas Inventory, production pneumatics emitted 1,060 kilotons of CH_4 in 2017, accounting for 16 percent of the total CH_4 emissions from the natural gas supply chain. Pneumatic device activity is concentrated at production facilities and there were 833,000 pneumatic devices used by U.S. production facilities in 2019 (NETL, 2019). The above results show that pneumatic devices are a key contributor to GHG emissions for both conventional and unconventional technologies.

Natural gas is compressed for transport from the processing facility to the consumer, so upstream GHG emissions are sensitive to pipeline distance and the number of compressors that the natural gas must pass through. The energy intensity of compression and the fugitive CH_4 emissions from compressors both contribute to upstream emissions (NETL, 2019). In addition to being a source of CH_4 emissions, compressors are also a source of CO_2 emissions. Most compressors in the U.S. pipeline transmission network are powered by natural gas that is withdrawn from the pipeline itself. Electric motors are not widely used by natural gas pipelines but are installed where local emission regulations limit the use of internal combustion engines or where inexpensive electricity is available (Hedman, 2008). Approximately three percent of compressors used by the natural gas transmission network are electrically driven.

Compression systems have two sources of CH_4 emissions: CH_4 that slips through combustion exhaust and CH_4 that escapes through compressor seals or packing. Natural gas systems use centrifugal and reciprocating compressors. Centrifugal compressors are more appropriate for pressure boosting applications in a steady-state application (such as a transmission pipelines), and reciprocating compressors are more appropriate when gas flow is variable and when large increases in pressure are required. Centrifugal compressors are typically driven by gas-fired turbines but, in some instances, are driven by an electric motor; reciprocating compressors are driven by gas-fueled engines. Exhibit 2-6 illustrates the emissions associated with pneumatic devices and compressors.

Exhibit 2-6. GHG emissions from pneumatic devices and compressors across the NG supply chain

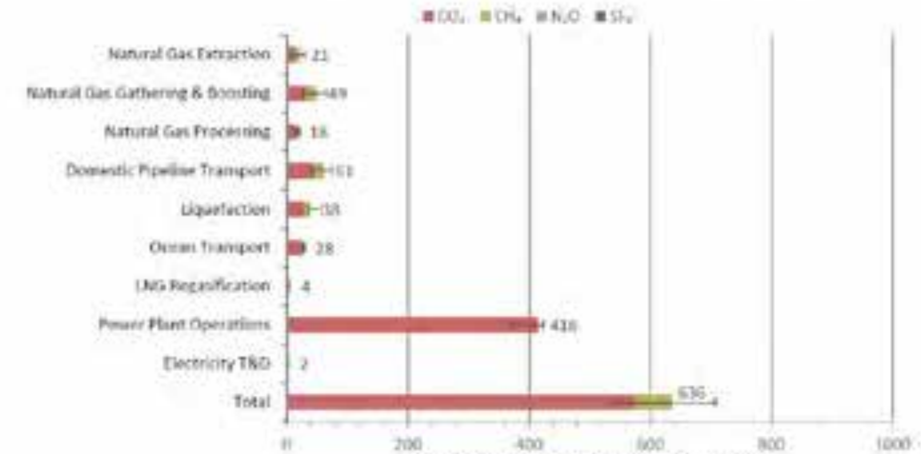


For all natural gas production types, the GHG results are sensitive to production rates and episodic emissions (either liquid unloading or workovers). For the delivery of 1,000 kilograms (kg) of natural gas to a power plant, 12.5 kg of CH_4 are released to the atmosphere, 30.3 kg are flared to CO_2 via environmental control equipment, and 45.6 kg are combusted in process equipment. When these mass flows are converted to a percent basis, CH_4 emissions to air represent a 1.1 percent loss of natural gas extracted, CH_4 flaring represents a 2.8 percent loss of natural gas extracted, and CH_4 combustion in equipment represents a 4.2 percent loss of natural gas extracted. These percentages are based on *extracted* natural gas. Converting to a denominator of *delivered* natural gas gives a CH_4 leakage rate of 1.2 percent (NETL, 2019).

The factors for episodic emissions are based on the supporting documentation for EPA's national GHG inventory. EPA's emission factor for unconventional well completions and workovers are 9,000 thousand cubic feet (Mcf) of natural gas emissions per episode, which was developed from a series of presentations by their Natural Gas Science to Achieve Results (STAR) program. The data behind this emission factor are highly variable, ranging from 6,000 to over 20,000 Mcf per episode (6–20 million cubic feet [MMcf] per episode), and include data collected in the 1990s (EPA, 2010; Cathles, 2012). It should also be noted that this emission (9,000 Mcf/episode) and other emissions from unconventional extraction operations can be captured and flared using current technologies (Cathles, 2012). An increase in flaring rate will significantly reduce the GHG emissions from unconventional natural gas production.

An NETL (2019) report that analyzed the lifecycle emissions of exporting U.S. LNG to Europe yielded the following emissions output (assuming end-use in electricity generation) found in Exhibit 2-7.

Exhibit 2-7. GHG emissions from exporting LNG from the United States to Europe



2.3 Other Natural Gas Analyses

Several other research teams have performed system-level LCAs of natural gas production using methodologies similar to those used and documented by NETL. The results of three non-NETL studies are generally consistent with NETL's planned analysis approach and indicate that the GHG emissions from unconventional production are comparable to, if not lower than, emissions conventional production. The widely cited exception is a study by Howarth et al. (2011) that shows higher emissions for unconventional gas relative to conventional natural gas and higher emissions for both relative to the other studies.

Jiang et al. (2011) estimated the GHG emissions from Marcellus Shale natural gas and compared them to U.S. domestic average natural gas. They concluded that development and completion of a Marcellus Shale natural gas well has GHG emissions that are 11 percent higher than the development and completion of an average conventional natural gas well. This 11 percent difference is based on a narrow boundary, representing only the differences in well development and completion for Marcellus Shale and conventional natural gas. When the life cycle boundaries are expanded to include combustion to generate electricity, the percentage difference between the GHG emissions from Marcellus Shale and conventional natural gas is reduced to 3 percent. In other words, as the boundaries of the systems are expanded, the differences in emissions between conventional and unconventional wells are overshadowed by other processes in the natural gas supply chain (Jiang et al., 2011).

Burnham et al. (2011) and Clark et al. (2011) estimated the GHG emissions from shale gas and compared it to conventional natural gas and other fossil energy sources. Their results show that shale gas emissions are 6 percent lower than those from conventional natural gas, but the

Commented [HSAJ56]: Change any and all instances of gas to natural gas throughout.

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overlapping uncertainty of the results prevents definitive conclusions about whether shale gas has lower GHG emissions than conventional gas.

Weber and Clavin (2012) applied Monte Carlo uncertainty analysis to a set of six natural gas LCAs being performed and concluded that the upstream GHG emissions from conventional and shale gas are similar. The six studies include four of the studies mentioned herein (Burnham et al., 2011; Howarth, 2011; Jiang et al., 2011; NETL, 2012), and two additional studies conducted at University of Maryland (Hultman et al., 2011) and Shell Global Solutions (Stephenson et al., 2011).[e] Weber and Clavin (2012) recommend the use of efficient technologies for converting natural gas to electricity, heat, or transportation applications. They also recommend implementation of reduced emission completions (RECs) for the development of shale gas wells.

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Research conducted by Howarth et al. (2011) concludes that the high volumes of gas released by hydraulic fracturing make the life cycle GHG footprint of shale gas significantly higher than conventional gas. According to Howarth's analysis, 3.6 to 7.9 percent of the natural gas extracted from shale gas wells is released to the atmosphere as CH_4.

Its important to note that the boundaries of these LCAs discussed here are not identical. For example, Jiang et al. (2011) and Weber and Clavin (2012) use the same boundaries as NETL (2019), but Argonne National Laboratory's analysis includes scenarios for vehicles that use compressed natural gas (Burnham et al., 2011) and Howarth's (2011) analysis includes distribution of natural gas beyond the natural gas transmission network to include small-scale end users. Fortunately, the transparency of these analyses allows boundary reconciliation, so the World Resources Institute (WRI) converted them to an upstream basis (from natural gas extraction through natural gas delivery via pipeline) (Bradbury et al., 2013). ***Exhibit 2-8*** shows the GHG results as compiled by WRI's study (Bradbury et al., 2013). These results use a 100-year time scale to show GHG emissions in terms of CO_2e/MJ of delivered natural gas. While WRI shows these results based on similar boundaries, each author used a different basis for calculating uncertainty. The error bars shown in ***Exhibit 2-8*** are a mix of data, parameter, and scenario uncertainties.

WRI also reconciled NETL's upstream natural gas results, shown in ***Exhibit 2-8***. However, WRI's reconciliation is representative of NETL's 2012 natural gas analysis. NETL's current results, representative of modeling updates made in 2012 and 2013, have expected values that are lower than other authors.

[e] The analysis by the University of Maryland (Hultman et al., 2011) concludes that unconventional natural gas has upstream GHG emissions that are approximately 2 percent higher than those from conventional natural gas; the analysis by Shell Global Solutions (Stephenson et al., 2011) concludes that unconventional gas has upstream GHG emissions that are 11 percent higher than those from conventional natural gas. These two analyses do not contradict nor expand upon the conclusions of the other upstream natural gas analyses discussed in this report, so they are not discussed further.

Exhibit 2-8. Upstream GHG comparison between conventional and unconventional natural gas

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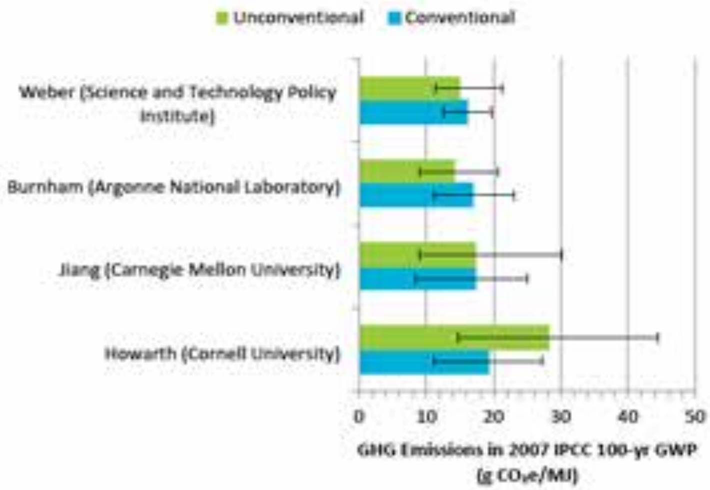

The studies shown in Exhibit 2-9 identify extraction, processing, and transport as sources of CH_4 leakage, but, other than well completion emissions, do not specify the sub-activities that contribute to CH_4 leakage. As identified by NETL's model, the top four contributors to CH_4 leakage from unconventional natural gas are completions, workovers, pneumatically-controlled valves used at extraction, and compressors used during processing and pipeline operations (NETL, 2014).

Exhibit 2-9. Comparison of leakage rates from upstream natural gas

Author	CH_4 Leakage Rate	
	Conventional Onshore	Unconventional
Weber (Science and Technology Policy Institute)	2.80%	2.42%
Burnham (Argonne National Laboratory)	2.75%	2.01%
Howarth (Cornell University)	3.85%	5.75%

Because of the potency of CH_4 as a GHG, CH_4 leakage rates dominate the GHG emissions from upstream natural gas systems. Exhibit 2-9 compares the CH_4 leakage rates for conventional and unconventional natural gas extraction, as calculated by three analyses. As discussed earlier, NETL's leakage rate for the 2010 supply mix of all domestic natural gas sources is 1.2 percent and is expressed in terms of CH_4 emissions per unit of natural gas delivered to a large-scale consumer. Jiang does not explicitly report a CH_4 leakage rate. The boundaries on these leakage rates are from extraction through delivery (Bradbury et al., 2013).

The differences in GHG emissions and CH_4 leakage rates among natural gas analyses are driven by different data sources, assumptions, and scopes (Bradbury et al., 2013). Other differences among these analyses, as identified in literature, are summarized below.

Most analysts use IPCC GWPs to scale CH_4 to an equivalent quantity of CO_2. Howarth does not use IPCC GWPs, but uses GWPs developed by Shindell, a National Aeronautics and Space Administration scientist whose calculations account for the heating and cooling effects of aerosols in addition to GHGs (Howarth et al., 2011). On a 100-year time frame, the IPCC and Shindell GWPs for CH_4 are 25 and 33, respectively (Bradbury et al., 2013; Howarth et al., 2011; MIT, 2011). Howarth uses a CH_4 GWP that is 32 percent higher than used by others, but further analysis and reconciliation is necessary to determine how much Howarth's unique GWP contributes to the difference between Howarth's and others' GHG results; the choice of GWP factors is one of several modeling and data choices unique to Howarth's analysis. Howarth (2012) acknowledges the uncertainty in GWPs and defends his use of Shindell GWPs on the basis that they are representative of the most recent science.

Commented [HSAJ60]: Is this a direct quote from the study? If so, cite accordingly.

GWPs will change as scientific understanding of climate change progresses. The IPCC recently finalized its Fifth Assessment Report (AR5) on climate change, which includes GWPs that will supplant the GWPs from the fourth assessment report (released in 2007). AR5 increases the 100-year GWP of CH_4 from 25 to 28. Further, if the global warming caused by the decay of CH_4 to CO_2 is to be included within the boundaries of an analysis, AR5 recommends a 100-year GWP of 30 for CH_4. The GWP of CH_4 is a function of the radiative forcing directly caused by CH_4 in the atmosphere, as well as the radiative forcing from products of CH_4 decay. IPCC increased the GWP of CH_4 based on new data that shows that the lifetime of CH_4 in the atmosphere is 12.4 years (a 12-year lifetime was used in the previous version). IPCC also increased the GWP of CH_4 based on revised assumptions about relationships among CH_4, ozone, and water vapor in the atmosphere (Stocker et al., 2013).

There is uncertainty as to how much CH_4 is released during the initial flowback of water from an unconventional well. The emission of natural gas from flowback water accounts for most of the emissions from the completion of shale gas wells. EPA's emission factor for natural gas released from the flowback from unconventional completions is approximately 9,000 Mcf per episode. The data behind EPA's emission factor are highly variable, ranging 6,000–20,000 Mcf/episode, and include data collected in the 1990s (EPA, 2010). NETL (2014) uses EPA's emission factor for flowback emissions. Carnegie Mellon University's analysis of upstream natural gas assumes that flow back CH_4 emissions are equal to the total gas produced during the first 30 days of production (4,100 Mcf per episode) (Jiang et al., 2011). Howarth (2011) averages the flowback emissions from two shale gas wells and two tight gas wells and concludes that flowback emissions are 1.6 percent of the total gas produced by a well during its entire life. Howarth does not explicitly state a flowback emission factor in terms of Mcf/episode but applying Howarth's 1.6 percent loss factor to the four wells cited in Howarth's analysis translates to flowback emissions of 47,000 Mcf/episode. Another data point is an emission factor of 5,000 Mcf/episode, which was developed by Southern Methodist University for the Environmental Defense Fund (EDF) and is representative of shale gas development in the Barnett Shale (Armendariz, 2009). The flowback emissions used by other authors discussed in this report are not clearly stated in their work.

Howarth (2012) does not use EPA's emission factor to characterize flowback emissions but rather compiles data from five basins where unconventional extraction is occurring (Barnett, Piceance, Uinta, Denver-Jules, and Haynesville) and assumes a 10-day period in the last stages of flowback during which gases "freely flow." The data that Howarth (2012) uses to characterize the Haynesville basin is especially high, ranging 14–38 MMcf/day. Other analysts claim that the flowback fluid does not contain as much gas as indicated by Howarth's data. During flowback, non-gaseous material obstructs the wellbore and prevents the release of CH_4 and other gases (Bradbury et al., 2013; Cathles, 2012; O'Sullivan and Paltsev, 2012).

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Estimated ultimate recovery (EUR) is used to apportion the one-time impact of flowback emissions per unit of natural gas produced (Howarth, 2012; Hughes, 2011; NETL, 2014). NETL (2014) uses EURs of 3.0 and 3.25 billion cubic feet (Bcf) for Barnett Shale and Marcellus Shale, respectively, based on 2009 production data for the Barnett play (levelized over 30 years of production), and a decline curve analysis[e] of initial production rates reported by producers in the Marcellus play. Jiang et al. (2011) use an EUR of 2.7 Bcf over a 25-year period and note that some producers have EURs as high as 7.3 Bcf. Howarth (2012) points to the uncertainty in lifetime production rates for unconventional wells and contends that the EURs used by NETL and Jiang are too high. To represent the EUR of all unconventional wells, Howarth uses a value of 1.24 Bcf, which is based on a decline curve analysis of Barnett Shale wells (Hughes, 2011). The variability in EURs for shale gas wells is due to a lack of long-term historical production data. Shale gas wells use new technologies to extract natural gas from previously unproductive geological formations; EURs are merely estimates of long-term performance using initial production data and assumptions about long-term performance (NETL, 2014). As shale gas extraction develops, the uncertainty in EURs will be reduced.

Flaring is the controlled combustion of natural gas that cannot be easily captured and sold. Unconventional gas is sometimes flared during well completion. Flaring is an important safety practice, and it also reduces the GWP of natural gas extraction and processing operations by converting CH_4 to CO_2. Again, zero venting is the ultimate goal, but if venting happens, then it is environmentally preferable to flare vented gas because flaring reduces the GWP of the vented gas (NETL, 2019). Analysis performed by NETL (2019) and O'Sullivan and Paltsev (2012) assumed a 15 percent flaring rate.

Most natural gas analyses use EPA's national GHG inventory to calculate natural gas pipeline emissions. The national inventory data accounts for the different fates of CH_4 (fugitive emissions, venting from compressors, and combustion in compressors) during natural gas transport (Bradbury et al., 2013; NETL, 2014). Howarth does not use guidance from the national GHG inventory to account for the sources of CH_4 emissions during natural gas transmission (Howarth et al., 2011; Cathles et al., 2011). Howarth assumes that the difference in CH_4 between the inlet and outlet of the pipeline is equal to CH_4 emissions from pipeline operation. This mass balance approach does not account for the consumption of CH_4 by pipeline compressors (Cathles et al., 2011). Pipeline compressors combust CH_4 for compression energy, converting CH_4 to CO_2 in the process (NETL, 2014). Howarth (2012) acknowledges the limitation

[e] The production rate of a well declines as the well gets older. A decline curve analysis plots the production rate of a well over time; the area under the curve represents the total lifetime production of the well. By knowing the initial production rate of a well and then assuming a shape for the production curve, the total lifetime production of the well can be estimated.

of his approach, but also points out that EPA inventory data are more than ten years old and rely too heavily on voluntary industry reporting (Bradbury et al., 2013).

Howarth includes two phases of natural gas transport: transmission and distribution (Howarth et al., 2011; Cathles et al., 2011). Transmission moves natural gas from a processing plant to large-scale consumers near cities or export terminals; distribution is an additional step that moves natural gas to commercial or residential consumers (EIA, 2008). Howarth (2012) points out that heat generation, which includes a large share of small residential and commercial consumers and requires a natural gas distribution network, accounts for the largest share of natural gas consumption in the United States. Other natural gas analyses focus on the use of natural gas for power generation, which does not require natural gas distribution (NETL, 2019; Bradbury et al., 2013).

Collaboration between the University of Texas and EDF is a recent example of how data collected at natural gas extraction sites can inform natural gas analysis. Emissions were measured at 489 natural gas wells across the United States and include conventional and unconventional extraction technologies. Based on these measurements, the University of Texas calculated that the total CH_4 emissions from natural gas extraction represent a 0.42 percent loss of CH_4 at the extraction site; this loss factor is an aggregate of conventional and unconventional wells and represents only the natural gas production activities at the extraction site, not processing or pipeline transmission. The measurements also include emissions from 27 unconventional completions and show that environmental control equipment can reduce the CH_4 emissions from unconventional completion to levels that are 97 percent lower than the completion emissions currently estimated by EPA. The University of Texas and EDF have published only one paper about their research to this point, although additional papers are expected (Allen et al., 2013).

A survey conducted by the American Petroleum Institute (API) and America's Natural Gas Alliance (ANGA) is an example of how data collected by industry can inform the emission factors used by analysts. These organizations surveyed 20 member companies to collect data from 91,000 domestic natural gas wells. Based on the survey, API and ANGA conclude that the rate of workovers for unconventional wells (also known as "refracture frequency") is one-tenth of the rate specified by EPA's documentation of the oil and gas sector (Shires et al., 2012).

Brandt et al. (2014) reviewed 20 years of technical literature on natural gas emissions in North America and demonstrated that the CH_4 emission factors used by different authors are highly variable. One source of variability is the way in which CH_4 emissions data are collected; some emissions are measured at a device level (e.g., the flowback stream from a hydraulic fracturing job), while other emissions are measured at regional boundaries (e.g., atmospheric sampling in a region that has natural gas production). Theoretically, if these two types of measurements are scaled correctly, they should result in similar CH_4 emission factors; however, the two methods lead to GHG results that differ by a factor of ten. Brandt et al. (2014) conclude that improved science for determining CH_4 leakage will lead to cost-effective policy decisions.

Improper well construction and fractures in rock formations can also result in CH_4 emissions from the target formation during production. The current life cycle models for shale gas extraction do not include groundwater as a source of GHG emissions. CH_4 migration as a potential source of drinking water contamination is discussed in greater detail in Chapter 4 – Water Use and Quality.

Littlefield et al. (2022) show that geography matters in terms of GHG emissions from the natural gas supply chain. Where gas is produced and ultimately used plays a tremendous role in total GHG emissions, so much that a national average value is not adequate. Their work provides a detailed life cycle perspective on GHG emissions variability owing to where natural gas is produced and where it is delivered. They disaggregated transmission and distribution infrastructure into six regions, balanced natural gas supply and demand locations to infer the likely pathways between production and delivery and incorporated new data on distribution meters. The average transmission distance for U.S. natural gas is 815 kilometers (km) but ranges 45–3,000 km across estimated production-to-delivery pairings. In terms of total GHG emissions, the delivery of 1 MJ of natural gas to the Pacific region has the highest mean life cycle GHG emissions (13.0 g CO_2e/MJ) and the delivery of natural gas to the Northeast United States has the lowest mean life cycle GHG emissions (8.1 g CO_2e/MJ).

MacKinnon et al. (2018) demonstrate that natural gas generation and the natural gas system could play several important roles in supporting sustainable energy strategies over time that can achieve societal GHG reduction goals and help the transition to renewable sources. Natural gas generation can support transitions to renewable resources 1) by use in advanced conversion devices to provide complementary grid services efficiently and with very low emissions to maximize the benefits of intermittent renewable resources, and 2) natural gas generation and the existing natural gas system can support the use of renewable gaseous fuels with high energy and environmental benefits. In 2020, NETL collaborated with industry and published an analysis of Our Nation's Energy Future's (ONE Future) portfolio of assets (Rai et al., 2020). ONE Future is a natural gas industry partnership dedicated to improving the efficiency of the natural gas supply chain. ONE Future represents 1–13 percent of total throughput in the respective segments of the natural gas industry value chain. The expected life cycle CH_4 emission rate for ONE Future average natural gas is 0.76 percent (with a 95 percent confidence interval ranging of 0.49–1.08 percent). The expected life cycle CH_4 emission rate for the U.S. average scenario is 1.06 percent. In terms of IPCC 100-year GWP, the ONE Future and U.S. average scenarios emit 9.7 and 14.1 g CO_2e/MJ of delivered natural gas, respectively.

Balcombe et al. (2016) document the wide range of CH_4 emissions estimates across the natural gas supply chain. Estimates of combined CH_4 and CO_2 emissions ranged from 2–42 g CO_2e/MJ.

2.4 Mitigation Measures

The NSPS regulates emissions from the oil and gas sector. The new regulations are applicable to new or modified wells. The final NSPS rule that was established in August 2012 focuses on RECs, compressor seals, storage tanks, and pneumatic controllers. RECs use portable equipment that is brought onsite to capture gas from the solids and liquids generated during the flowback of hydraulic fracturing water. RECs equipment includes plug catchers and sand traps that remove drilling cuttings and finer solids that result from well development. Three phase separators are used to separate gas and liquid hydrocarbons from flowback water. These separation processes are necessary only during completions and workovers to prevent the release of CH_4 and other gases to the atmosphere and to reduce the need for flaring (EPA, 2011a).

Compressor seals include the wet seals used by centrifugal compressor and the rod packing used by reciprocating compressors. Wet seals surround the rotating shaft of a centrifugal compressor with oil, which prevents gas leakage from the compressors. The oil used by wet seals must be continuously regenerated, which releases CH_4 to the atmosphere. By replacing wet seals with mechanical dry seals, the CH_4 emissions from centrifugal compressors can be reduced (EPA, 2011b). Reciprocating compressors prevent CH_4 leakage by encasing each compressor rod with a set of oil-coated, flexible rings. Proper maintenance and routine replacement of these rings prevents unnecessary leakage of CH_4 (EPA, 2006c). Storage tanks hold flowback water and liquid hydrocarbons recovered from the production stream. Variable loading levels and temperatures cause the venting of CH_4 and other gases from these tanks. By installing vapor recovery units on storage tanks, producers can reduce emissions from natural gas production (EPA, 2006b). The captured emissions can be combusted onsite to provide process energy, or they can be channeled to the sales stream. Pneumatic controllers use gas pressure to open and close valves throughout a natural gas production and processing system. Natural gas is commonly used to pressurize pneumatic control systems. The bleeding of natural gas from pneumatic controllers vents CH_4 to the atmosphere. The GHG impact of pneumatic control systems can be reduced by installing pneumatic systems that use pressurized air instead of pressurized natural gas (EPA, 2006a). Since the regulations focus on RECs, they are more applicable to unconventional wells. However, the regulations also mandate emission reductions from pneumatically-controlled valves and compressor seals, which are two types of emission sources common to conventional and unconventional technologies.

The 2012 NSPS regulations do not cover emissions from liquid unloading or natural gas pipeline transmission. Participants in the Natural Gas STAR program have demonstrated that automated plunger lift systems can remove liquids from the wellbore at optimal frequencies that prevent the venting of natural gas to the atmosphere. Other technologies for reducing emissions from liquids unloading include the use of smaller diameter tubing that maintains production pressures at levels that reduce the frequency of liquid unloading, and foaming agents that reduce the density and surface tension of accumulated liquid (EPA, 2011c). The replacement of wet seals and rod packing on transmission pipeline compressors and applying the same type of improvements that can be applied to compressors at extraction and processing sites, can further reduce pipeline emissions and product losses. The goal of NSPS is to reduce CH_4 emissions from the targeted sources (completions, compressors, pneumatic valves, and storage tanks) by 95 percent.

A NETL (2020) report notes that compressed-air pneumatics are a mature technology that reduces CH_4 emissions from pneumatic systems. The technology replaces existing devices, which are actuated by natural gas, with devices that are actuated with compressed air. This requires the addition of electric-powered air compressors at natural gas facilities but can result in zero CH_4 emissions from pneumatics. A barrier to implementation of compressed-air pneumatics is electricity availability. The United States has an extensive electricity grid, but grid connections are not always near production sites. The same NETL (2020) report notes that proven technologies exist for reducing CH_4 emissions from compression systems:

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- Centrifugal compressors emissions can be reduced by replacing wet seals with dry seals. These seals are used around the rotating shaft of the compressor and prevent high pressure gas from escaping the compressor. Wet seals involve the use of recirculating oil that emits 40–200 standard cubic feet (scf) of natural gas per minute (min). Dry seals use gas to seal the compressor shaft and emit only 6 scf/min (EPA, 2006a). The replacement of wet seals with dry seals reduces centrifugal compressor emissions by 85–97 percent.
- Reciprocating compressor emissions can be reduced by replacement of rod packing. Packing prevents gas from moving around piston rods and escaping the compression cylinder. New packing that is properly installed on a well-maintained compressor will emit about 12 scf/hour. The emission rate for old or poorly installed packing can range 25–67 scf/hour (EPA, 2006a). When compared to emission rate for new packing, this equates to potential emission reductions of 52–82 percent. Rod packing replacement is a mature technology, but there are new technologies that can also reduce reciprocating engine exhaust slip. These new technologies include advanced materials that increase piston rod service life while reducing rod wear and Teflon-coated rings that reduce friction while maintaining a tight seal. There are no data on the emission reduction potentials of these new technologies.
- The majority of the CH_4 emissions from reciprocating compressors are due to the CH_4 slip from engine exhaust. Comparing the exhaust emission factors for rich burn and lean burn engines shows that lean burn engines have a combustion effectiveness of 97 percent and lean burn engines have combustion effectiveness of 99 percent. Air-fuel-ratio controls are an option for improving the combustion effectiveness of lean burn engines while keeping NO_x emissions low. More research is required to understand the limits of air-fuel-ratio controls but, for this analysis, it is assumed that they can increase the combustion effectiveness of a lean burn engine by 97-99 percent (EPA, 2006a).

Exhibit 2-10. Quantification of mitigation measure impact for pneumatic devices and compressors

Strata	Stage	Pneumatic Devices	Compressor (centrifugal)	Compressor (reciprocating)	Exhaust (turbine)	Exhaust (engine)
Before Mitigation	Production	1.02E+06	N/A	4.50E+03	N/A	1.48E+05
	Gathering and Boosting	N/A	1.34E+04	2.84E+03	4.41E+02	3.96E+05
	Processing	N/A	2.01E+04	4.40E+04	9.90E+02	1.35E+05
	Transmission and Storage	N/A	1.94E+04	6.26E+04	1.34E+03	8.71E+04
After Mitigation	Production	5.10E+05	0.00E+00	3.55E+03	N/A	8.38E+04
	Gathering and Boosting	N/A	2.73E+04	2.32E+03	4.41E+02	2.17E+05
	Processing	N/A	8.26E+03	3.17E+04	9.90E+02	8.12E+04
	Transmission and Storage	N/A	1.42E+04	4.24E+04	1.34E+03	5.21E+04

With respect to liquefaction, Mokhatab et al. (2014) notes that most of the plant energy consumption and resultant emissions in natural gas liquefaction facilities occurs in the compressor drivers where fuel energy (usually natural gas) is converted to mechanical work (or

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electricity in case of electrically driven compressors). Due to the energy consumption scale of the LNG plants, any enhancement to the energy efficiency of LNG plants will result in a significant reduction in gas consumption and consequently CO_2 emission (Mokhatab et al., 2014). There are two ways to increase the energy efficiency of natural gas liquefaction cycles: liquefaction cycle enhancement and driver cycle enhancement. Liquefaction cycle enhancements reduce the compressor power and consequently the compressor driver's fuel consumption. Driver cycle enhancement reduces the amount of fuel consumption to generate a specific amount of power. Typical natural gas liquefaction cycles utilize either pure refrigerant in cascade cycles, expansion-based cycles, or mixed refrigerant cycles. Pure refrigerant cycles have a constant evaporating temperature that is a function of the saturation pressure. Mixed refrigerant cycles, on the other hand, do not maintain a constant evaporating temperature at a given pressure. Their evaporating temperature range, called temperature glide, is a function of their pressure and composition. A refrigerant mixture of hydrocarbons and nitrogen (N_2) is chosen so that it has an evaporation curve that matches the cooling curve of the natural gas with the minimum temperature difference. Small temperature difference reduces entropy generation and, thus, improves thermodynamic efficiency, reduces power consumption, and reduces emissions associated with liquefaction facilities (Mokhatab et al., 2014).

A study from Pospíšil et al. (2019) notes that a certain part of the energy spent on liquefaction can be recovered by the utilization of cold stream from LNG. The amount of usable cold is given by thermophysical properties of natural gas and corresponds to 830 kilojoule (kJ)/kg of LNG. This cold energy can be recovered during the regasification process. Regasification is carried out either in port terminals before natural gas is transported via gas lines or directly before the use of natural gas. The exploitation of cold from LNG is quite limited at present. Most of the available cold is wasted during the regasification process when LNG is heated up by water or ambient air. Wasting of cold reduces the overall efficiency of this primary energy source and leads to greater emissions. Promising ways of utilizing cold from LNG in the regasification process should be explored and implemented (Pospíšil et al., 2019).

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The goal of NSPS is to reduce CH_4 emissions from the targeted sources (completions, compressors, pneumatic valves, and storage tanks) by 95 percent. NSPS implementation is applicable only to extraction and processing activities and, based on NETL's (2014) natural gas model, could reduce upstream GHG emissions from the domestic natural gas mix (which includes conventional and unconventional technologies) by 23 percent.

From a national perspective, a reduction in CH_4 emissions from natural gas systems could reduce the annual U.S. GHG inventory. In 2011, natural gas systems (processes for the extraction, processing, transport, and storage of natural gas) released 145 teragrams of CO_2e of CH_4 to the atmosphere (EPA, 2013). The total U.S. GHG inventory in 2011 was 5,800 teragrams of CO_2e, (EPA, 2013) so CH_4 from natural gas systems is 2.5 percent of the total GHG inventory. As discussed above, NSPS reductions can reduce upstream GHG emissions by 23 percent, which means they can reduce the entire U.S. GHG inventory by 0.6 percent.

2.5 References

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3 AIR QUALITY

Key sources of non-GHG emissions from natural gas systems affecting air quality are as follows:

- *Uncaptured Venting*: Releases natural gas, which is a source of VOC emissions. Most uncaptured venting comes from compressor systems. Compressor systems are prevalent in most supply chain stages.
- *Fuel Combustion*: Produces a wide variety of air emissions, including NO_x, carbon monoxide (CO), sulfur dioxide (SO_2), and particulate matter (PM).

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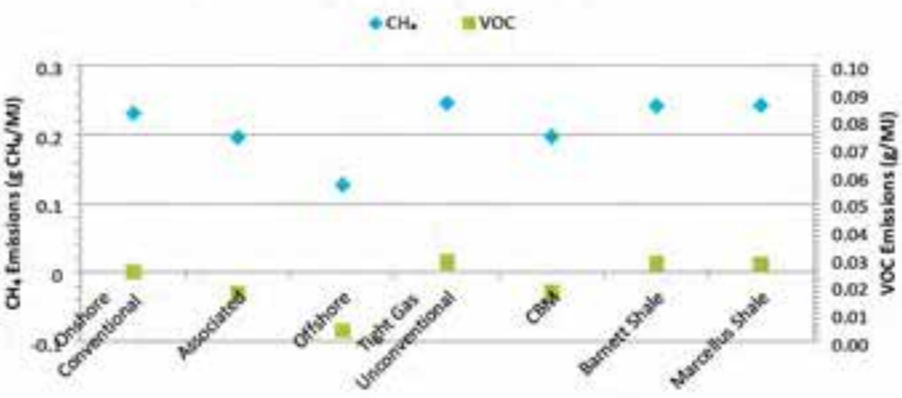
3.1 UNCAPTURED VENTING

The venting of natural gas during extraction and processing is a key source of VOC emissions. VOCs, like CH_4, are a naturally occurring constituent of natural gas[f] and react with other pollutants to produce ground-level ozone. Since VOCs come from the same sources as CH_4, an understanding of the sources of CH_4 emissions from natural gas provides a basis for understanding the sources of VOC emissions from upstream natural gas. As shown by Exhibit 3-1, the pattern of VOC emissions among natural gas types follows the same pattern as CH_4 emissions among the same natural gas types.

Exhibit 3-1. Comparison of CH_4 and VOC emissions from upstream natural gas



The emissions (VOCs and CH_4) from offshore natural gas extraction (also shown in Exhibit 3-1) are relatively low because offshore platforms have high production rates that justify capital expenditures on loss reduction technologies which help prevent unnecessary venting. The confines of offshore extraction platforms also present a safety challenge, which requires the prevention of flammable gases, such as CH_4 or VOCs (NETL, 2014). The success of offshore

[f] Unprocessed natural gas has an average VOC composition of 18 percent by mass, and processed natural gas has a VOC composition of 5.6 percent by mass (NETL, 2014).

platforms at mitigating natural gas losses illustrates that existing technologies are effective at reducing VOC emissions from natural gas extraction. There are no technological barriers to applying such emission reduction technologies to shale gas or other sources of natural gas.

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The emission reduction opportunities for VOCs are the same as those for CH_4 emissions. RECs use portable equipment that captures and flares natural gas during well development. Optimized timing of plunger lifts for liquid unloading prevents unnecessary venting of natural gas from conventional onshore wells. New technologies for valve control use compressed air instead of natural gas, which prevents the venting of natural gas from the bleeding of pneumatic control lines. Dry seals for centrifugal compressors and routine maintenance of rod packing in reciprocating compressors can reduce VOC emissions from upstream natural gas. These emission reduction opportunities are targeted by the NSPS, and are estimated to be capable of reducing venting emissions, including VOCs, by 95 percent (Clark et al., 2012; NETL, 2014).

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Another source of VOC emissions from the oil and gas sector is venting from condensate storage tanks (EPA, 2012b). The use of condensate storage tanks varies by region. If natural gas is produced in a region with wet gas, then the production of natural gas could result in VOC emissions from condensate storage tanks. If natural gas is produced in a region with dry gas, then the production of natural gas does not result in VOC emissions from condensate storage tanks.

A study conducted by Southern Methodist University for EDF used a bottom-up approach to calculate air emissions from natural gas extraction. The analysis focused on gas extraction in the Barnett Shale region. It categorized emissions into point, fugitive, and intermittent sources. Point sources include steady-state operation of compressors and condensate storage tanks. Fugitive sources include uncaptured gas venting from steady-state production processes. Intermittent sources represent the gas vented to the atmosphere during well development or occasional maintenance activities.

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The study concluded that venting from condensate storage tanks is a key contributor to the VOC inventory in the Barnett region. VOC emissions in this region are especially high in the summer when high ambient temperatures increase the venting rate of condensate storage tanks. The rate of VOC emissions from condensate storage tanks in the Barnett region has smog-forming potential comparable to the on-road vehicle emissions from the five-county region that includes Dallas-Fort Worth (Armendariz, 2009). This does not necessarily mean that the VOC emissions from condensate storage tanks in the Barnett Shale region can cause the same level of smog generated by on-road vehicles in the Dallas-Fort Worth area, just that VOC emissions have the potential. Its important to note, smog formation is a multivariable phenomenon; VOCs cause smog only when they are in the presence of NO_x emissions (EPA, 2012a).

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In contrast to bottom-up methods for calculating air quality emissions, a study conducted by Pétron et al. (2012) with the National Oceanic and Atmospheric Administration (NOAA) modeled air quality from natural gas activity using a top-down method that divided total measured emissions from an entire region by total natural gas produced in the region (Pétron et al., 2012). The goal of the analysis was to assess the effect of rapid growth in the oil and gas industries on air quality in the Rocky Mountain region, which had over 20,000 wells in 2008. Air quality data were collected from a 300-meter-tall tower (located 35 kilometers north of Denver) and "automobile-based on-road" air sampling equipment. Pétron et al. (2012) concluded that four percent of extracted natural gas (a combination of CH_4 and VOCs) is vented. This result is higher than the natural gas leakage rates calculated by NETL and other authors (which range 2–3 percent) but is within the range of natural gas leakage rates calculated by Howarth (3.6–7.9 percent). A more detailed discussion of natural gas leakage rates is included in Chapter 2 – Greenhouse Gas Emissions and Climate Change.

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Pétron et al. (.2012) was one of the first studies that used actual field measurements to calculate leakage rates from unconventional gas. However, the study uses data from tight gas production, so the conclusions do not necessarily apply to leakage from shale gas production. Further, researchers at the Massachusetts Institute of Technology (MIT) point out that natural gas extraction is not the only activity in northeastern Colorado that produces CH_4 and VOC emissions (O'Sullivan and Paltsev, 2012). When the air quality data were collected in 2008, most wells in the region were in tight sand formations that produced oil and gas (O'Sullivan and Paltsev, 2012). In addition to wells, the region also includes midstream processing and gathering pipelines (O'Sullivan and Paltsev, 2012).

Commented [HSAJ77]: I recommend referencing the study in place of location where the research was performed. For example, instead of MIT this should be O'Sullivan and Paltsev (2012). Same comment applies throughout the rest of this section.

Michael A. Levi, an analyst at the Council of Foreign Relations, challenges the NOAA (Pétron et al., 2012) conclusions. Levi (2012) claims that NOAA relies on "unsupported assumptions about the molecular composition of vented natural gas." Levi applies a molar ratio between CH_4 and VOCs that he believes is more consistent with the sampled region to calculate CH_4 emissions that are more consistent with bottom-up models of natural gas production. Levi's conclusions do not explicitly explain the tradeoff between CH_4 and VOC emissions (given a fixed volume of vented natural gas, the volume of CH_4 decreases as the volume of VOCs increases). Applying a lower CH_4-to-VOC ratio to top-down emission data will *reduce* the calculated CH_4 emissions but will *increase* the calculated VOC emissions.

The Arkansas Department of Environmental Quality (ADEQ) (2011) conducted an air emissions study in 2008 using a hybrid of bottom-up and top-down modeling approaches. The study was funded by a grant from EPA. EPA and ADEQ had the goal of assessing the effects of shale gas development in the Fayetteville Shale in north central Arkansas. ADEQ's study used two methods for calculating air emissions from shale gas: 1) a system-wide inventory based on emission factors and 2) ambient air monitoring. The application of emission factors to represent all natural gas development and production activity in an entire region is an example of a bottom-up modeling approach, while the interpretation of ambient air data is an example of a top-down modeling approach. Both approaches are described in more detail below.

ADEQ developed a system-wide inventory of shale gas development in the Fayetteville Shale by scaling emissions factors by 2008 gas development activity. Emission factors are observed or calculated emissions for a specific process. ADEQ focused on processes specific to hydraulic fracturing, and the operation of compressors.

ADEQ calculated annual air emissions from all hydraulic fracturing in the Fayetteville Shale by applying an emission factor of 5,000 Mcf to the 704 new wells that were completed in 2008. The chosen emission factor of 5,000 Mcf/episode was taken from a similar analysis on Barnett

Shale (Armendariz, 2009) and represents the volume of natural gas vented to the atmosphere during the hydraulic fracturing of a single well. ADEQ's emission factor represents the volume of natural gas (which includes CH_4 and VOCs) released during hydraulic fracturing, and has the same boundaries as the completion emission factors for unconventional wells as discussed in Chapter 2 – Greenhouse Gas Emissions and Climate Change (for example, NETL uses a shale gas hydraulic fracturing emission factor of 9,175 Mcf/episode) and shown in *Exhibit 2-8*. ADEQ's emission factor (5,000 Mcf/episode) is discussed in this chapter because it was developed with the goal of evaluating shale gas emissions with impacts other than climate change.

ADEQ calculates total compressor emissions by factoring the combustion emissions from the operation of a single compressor by the 356 compressors used for natural gas distribution in the Fayetteville Shale. The emission inventory concluded that the VOC emissions from compressor stations are the largest source of VOC emissions from shale gas development in the Fayetteville Shale (ADEQ, 2011).

ADEQ used photoionization detectors to measure ambient VOC emissions in the Fayetteville Shale. A total of 14 air sampling sites were set up, including six drilling sites, three hydraulic fracturing sites, four compressor stations, and one control site. Elevated levels of VOC emission were measured near the drilling sites but were near minimum detection limits near all hydraulic fracturing sites, compressor stations, and the control site. ADEQ concluded that the open storage tanks for drilling mud and cuttings are the likely cause of elevated VOC emissions around the drilling sites. No data were collected on the composition of VOC emissions, so further data collection is necessary to assess the potential impacts of drilling VOCs on public health (ADEQ, 2011).

ADEQ did not identify condensate storage tanks as a significant source of VOC emissions from the development and operation of shale gas wells. The Fayetteville Shale produces dry natural gas, with heavy hydrocarbons (i.e., hydrocarbons with a higher mass than CH_4) comprising less than 0.5 percent of raw natural gas. The separation and storage of heavy hydrocarbons can be a significant source of VOC emissions for some regions. However, due to the low concentration of heavy hydrocarbons, the extraction of natural gas in the Fayetteville Shale does not have storage tanks for NGLs (ADEQ, 2011).

3.2 Combustion Emissions

The combustion of natural gas in compressors and gas processing equipment produces NO_x and CO. Similarly, the combustion of diesel in drilling equipment produces NO_x and CO, as well as significant quantities of PM and SO_2 emissions. The generation of grid electricity (used by a small share of natural gas compressors) produces these air pollutants as well.

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Exhibit 3-2 illustrates direct NO_x emissions from extraction activities as well as indirect NO_x emissions from the generation of electricity and other ancillary processes (NETL, 2014). NO_x emissions from Barnett Shale extraction and processing are 23 percent lower than those from Marcellus Shale extraction and processing. A key exception in these exhibits is the emissions from offshore extraction; offshore extraction platforms use centrifugal compressors, which have lower combustion emission factors than the reciprocating compressors used at onshore extraction sites (NETL, 2014).

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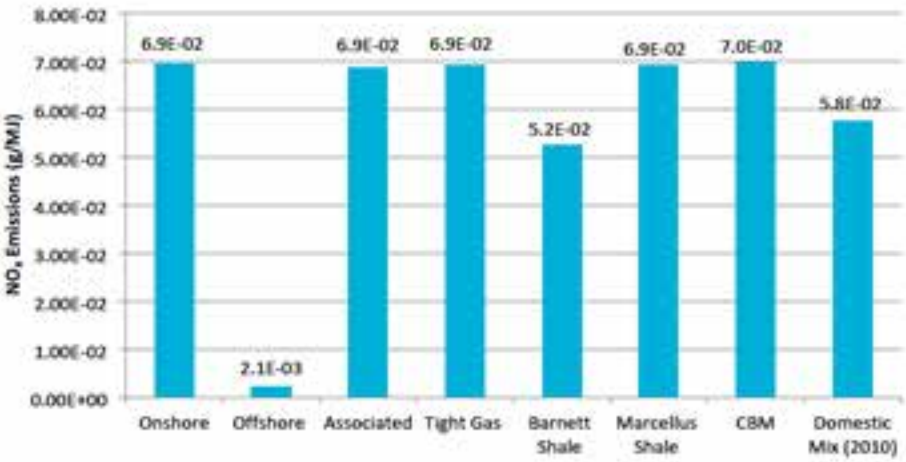
Exhibit 3-2. NO_x emissions from natural gas extraction and processing



The EDF analysis of the Barnett Shale also applied a bottom-up approach to calculate combustion emissions from natural gas production. They estimated region-wide compressor exhaust emissions of 46 tons of NO_x emissions per day. For comparison, they point out that the combined NO_x emissions from all airports in the area of the Barnett Shale region produce 14 tons of NO_x emissions per day. Suggesting the NO_x inventory from shale gas production in the Barnett Shale is at least three times higher than the NO_x inventory from area airports (Armendariz, 2009).

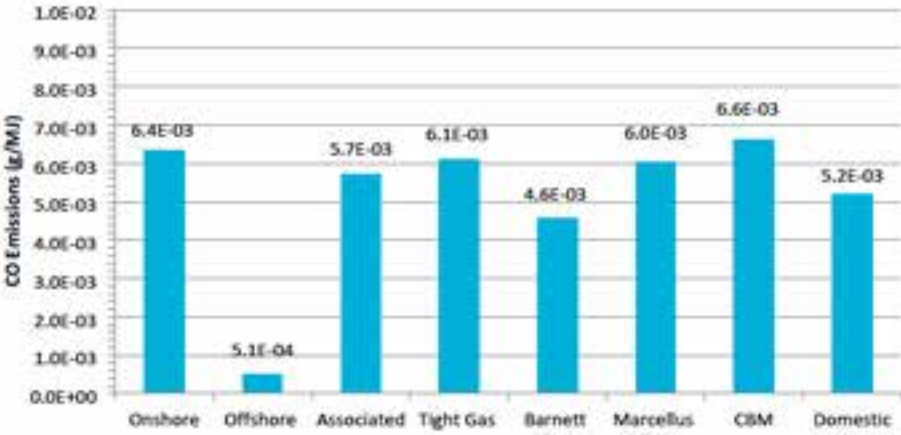
There are options for reducing NO_x emissions from natural gas production. One option for NO_x emissions reduction is the replacement of gas-fired compressor engines with electrically-powered compressors (ADEQ, 2011). Extraction sites in remote areas may not be near the electricity grid, but if electricity is available, the use of electrically-powered equipment can be a cost-effective way to reduce direct combustion emissions.

Increased use of electricity will increase indirect emissions of NO_x; however, as shown in Exhibit 3-2, which includes direct and indirect emissions, total NO_x emissions from Barnett Shale extraction are lower than those from other natural gas extraction sources. The one exception to this conclusion is offshore extraction, which uses centrifugal compressors that have lower NO_x emissions than the reciprocating compressors used by onshore technologies (NETL, 2014). As discussed in Chapter 2 – Greenhouse Gas Emissions and Climate Change, natural gas pipelines can also use electrically-powered compressors to meet local emission regulations and limit the use of internal combustion engines (Hedman, 2008).

NETL's conclusions for CO emissions are the same as their conclusions for NO_x emissions (NETL, 2014). The CO emissions from unconventional natural gas are comparable to those from conventional natural gas. This is illustrated in **Error! Not a valid bookmark self-reference.**.

which compares CO emissions among different natural gas types (NETL, 2014). (Again, offshore extraction has low CO emissions, because it uses centrifugal compressor technology.)

Exhibit 3-3. CO emissions from natural gas extraction and processing



According to ADEQ (2011), the combustion of natural gas does not produce significant PM and SO_2 emissions, but the use of diesel engines by drill rigs produces PM and SO_2 emissions. ADEQ's (2011) assessment of Fayetteville Shale identifies the use of drilling rigs during well completion as the largest source of PM emissions from gas production. NETL's assessment of natural gas shows that PM emissions are of the same order of magnitude for all natural gas sources (on the order of magnitude of 0.0001 g/MJ of gas extracted).

Indirect energy consumption can also affect the air quality profile of a gas extraction technology. If the development or operation of a natural gas well uses grid electricity, then the fuel mix of the electricity grid will affect the life cycle performance of the well. The indirect air quality impacts of electricity consumption depend on the fuel mixes and combustion characteristics of power plants that compose a regional electricity grid. For example, NETL's results show variance in SO_2 emissions among natural gas types. The SO_2 emissions from Barnett Shale are an order of magnitude greater than the SO_2 emissions from other onshore natural gas extraction technologies. This difference is due to the use of electricity by a portion of the compressors in the Barnett Shale. The fuel mix for grid electricity includes the combustion of coal, which is a source of SO_2 emissions (NETL, 2014).

3.3 Air Quality Studies on Venting and Combustion Emissions

Due to concerns about the air quality impacts from shale gas development, the East Texas Council of Governments commissioned an air quality assessment of the Haynesville Play, which as of December 2012 had nearly 3,000 shale gas wells (Environ, 2013). The air quality assessment collected data for VOC, NO_x, and CO emissions. The largest sources of these emissions were fugitive releases and combustion emissions from gas processing equipment and compressors. Compressors and gas processing equipment account for 79.7 percent of NO_x emissions and 90.1 percent of VOC emissions in the study. Fuel consumption by drilling rigs accounts for a smaller share of emissions—drilling rigs account for 16 percent of NO_x, and 1.2 percent of VOC emissions. Hydraulic fracturing accounts for less than 2 percent of NO_x emissions and less than 1 percent of VOC emissions. The authors acknowledge that there is significant uncertainty associated with future year projections of regional air emissions, but conclude that continued development of Haynesville Shale gas, even at a slow pace, will be large enough to affect the ozone levels in northeast Texas (Environ, 2013).

Litovitz et al. (2013) estimated the air pollutants from shale gas extraction in the Pennsylvania portion of the Marcellus Shale. They estimated VOC, NO_x, PM, and SO_2 pollutants by analyzing data for diesel trucks, well development (including hydraulic fracturing), natural gas compressor stations, and other natural gas extraction activities. They then scaled their estimates to the county and state levels. They concluded that compressor station activities account for at least 60 percent of extraction-related emissions; development activities, which include hydraulic fracturing, account for, at most, a third of extraction-related emissions. Litovitz et al. (2013) also compared the estimated pollutants from shale gas production to other industrial activities in Pennsylvania. They estimated emissions of VOC, PM, and SO_2 from shale gas production account for less than 1 percent of total air pollutants from all industrial sectors in Pennsylvania; NO_x emissions represent a higher share of total industrial air pollutants, at 2.9 to 4.8 percent of total industrial air pollutants. Shale gas air pollutants may be a small portion of state-wide industrial emissions, but they are not evenly distributed across the state. In counties with the most shale gas extraction, county-aggregated NO_x emissions are higher than the NO_x emissions from a major source, such as a power plant (Litovitz et al., 2013).

Further data collection efforts are necessary to characterize the regional variation in the volume and composition of vented natural gas. The University of Texas at Austin is leading a team of engineering firms and producers to measure CH_4 emissions from hydraulically fractured wells in the Barnett, Eagle Ford, Fayetteville, Haynesville, Denver-Julesberg, and Marcellus regions (Dittrick, 2012). NETL (2013) has air quality sampling in progress, which is using mobile equipment to measure VOCs and other air quality metrics in the Marcellus region.

SEAB views shale gas production as a key opportunity for increasing the U.S. natural gas supply but recommends the use of emission control technologies. SEAB recommends the use of state and federal regulations for timely implementation of emission control technologies. For example, the NSPS rules and National Emissions Standards for Hazardous Air Pollutants for the oil and gas sector will reduce smog precursors and other harmful pollutants. As noted by SEAB, a limitation of the new NSPS[g] rules are that they do not apply to existing shale gas wells unless the wells are re-fractured. Further, producers should also be expected to "collect and publicly share" emissions data (SEAB, 2011).

[g] Since NSPS rules reduce total gas leakage, they have the two-fold benefit of reducing CH_4 emissions (as discussed in Chapter 2 – Greenhouse Gas Emissions and Climate Change) as well as VOC emissions. NSPS implementation has climate and air quality benefits.

3.4 References

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4 Water Use and Quality

The literature describes the treatment and management of wastewaters as the central environmental concern regarding natural gas production in the eastern states, where water is abundant. To the west, where drier climates can limit the availability of freshwater, and deep underground injection wells for wastewater disposal are more readily available, the central concern discussed in the literature is the availability of water for drilling and hydraulic fracturing. It is estimated that drilling and hydraulically fracturing a shale gas well can consume between 2–6 MM gallons (gal) of water. As such, even the smallest local or seasonal water supply shortages can cause issue, even though water consumption for natural gas production generally represents less than 1 percent of regional water consumption (DOE, 2009). Water quality can be impacted due to inadequate management of water and fracturing chemicals on the surface, both before injection and after flowback and produced water. Subsurface impacts can result from the migration of fracturing fluids, formation waters, and CH_4 along well bores and through rock fracture networks. Management and disposal of wastewaters increasingly includes efforts to minimize water use and recycling and re-use of fracturing fluids, in addition to treatment and disposal through deep underground injection, with the risk of induced seismicity.

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4.1 Water Use for Unconventional Natural Gas Production

Water is used in unconventional natural gas production and, to a lesser extent, in the associated infrastructure for gas processing and testing pipelines (KPMG, 2012). Most of the water used for unconventional natural gas production is used for drilling for hydraulic fracturing. For example, of the total water used by the shale gas industry, hydraulic fracturing consumes about 89 percent, drilling uses 10 percent, and infrastructure consumes the remainder (Hayes and Severin, 2012). Water is also the main component of the fluids used for hydraulic fracturing, making up approximately 99 percent of the total volume.

Details on the types of chemicals and other agents combined with water used during well drilling and hydraulic fracturing are provided in Section 4.2.1. Segall and Goo (2011) cited SEAB (2011) in reporting that hydraulic fracturing uses 1–5 MM gal of water per well. Reduced surface water availability can harm ecosystems and human communities and groundwater withdrawals can permanently deplete aquifers. Hydraulic fracturing fluids, flowback water, and produced waters can pose risks to water quality. Proper treatment of these fluids is essential to protecting water resources.

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4.1.1 Water Consumption

DOE (2013) examined current and potential future impacts on the U.S. energy sector from three climate trends: increasing air and water temperatures, decreasing water availability, and increasing intensity and frequency of storms. DOE found that, in addition to be vulnerable to other trends, unconventional oil and gas production is vulnerable to decreasing water availability. Disruption of energy infrastructure in coastal regions due to storms and sea-level rise could also disrupt production. DOE cites two recent events as examples of impacts to the industry from decreasing water availability. In 2011, Grand Prairie, Texas (followed by other local water districts) restricted the use of municipal water for hydraulic fracturing and in the summer of 2012, operators in Kansas, Texas, Pennsylvania, and North Dakota faced higher water costs and were denied access to water usage for at least six weeks due to drought conditions (DOE, 2013).

The GAO (2010) examined the environmental impacts associated with commercial oil shale development, because oil shale, like natural gas from shales, uses substantial amounts of water. The GAO noted that the magnitude of impacts on water availability and quality from oil shale development is unknown. While water would likely be available during initial development of an oil shale industry, the size of the industry, particularly in Colorado and Utah, could eventually be constrained by the availability of water. Similar concerns have arisen for shale gas development in arid regions.

Water consumption per shale gas well can vary due to four sets of conditions:

- *Geology*: maturity of the shale and formation depth, thickness, and lateral extent
- *Technology*: horizontal and vertical drilling, water recycling
- *Operations*: operator decisions, availability of nearby freshwater
- *Regulatory*: requirements for use and treatment of water.

Drilling a shale gas well can consume between 65,000–1 MM gal of water or more, depending on the depth, horizontal length, and the geology of the formations through which the hole is drilled (see Exhibit 4-1) (DOE, 2009; Mathis, 2011; GAO, 2012a). Hydraulic fracturing can use 2–6 MM gal of water, which can be more than 95 percent of the water use per borehole as a single borehole can be hydraulically fractured multiple times (CRS, 2009). Nicot and Scanlon (2012) note that water use per well has increased over the last ten years as the lateral lengths and number of fracking stages has increased.

Exhibit 4-1. Average freshwater use per well

Shale Play	DOE (2009) (gal)			Mathis (2011) (gal)			GAO (2012a) (gal)		
	Drilling	Fracking	Total	Drilling	Fracking	Total	Drilling	Fracking	Total
Barnett	400,000	2,300,000	2,700,00	250,000	3,800,000	4,050,000	250,000	4,600,000	4,850,000
Eagle Ford	—	—	—	125,000	6,000,000	6,125,000	125,000	5,000,000	5,125,000
Fayetteville	60,000	2,900,000	3,060,000	65,000	4,900,000	4,965,000	—	—	—
Haynesville	1,000,000	2,700,000	3,700,000	600,000	5,000,000	5,600,000	600,000	5,000,000	5,600,000
Marcellus	80,000	3,800,000	3,880,000	85,000	5,500,000	5,585,000	85,000	5,600,000	5,685,000
Niobrara	—	—	—	300,000	3,000,000	3,300,000	300,000	3,000,000	3,300,000

EPA estimated that if 35,000 wells per year were hydraulically fractured in the United States, these wells would consume the equivalent of the water consumed by 5 MM people (Groat and Grimshaw, 2012). This scale of development was achieved during early shale gas activity when approximately 35,000 shale gas wells were drilled in 2006 (Halliburton, 2008). Data on the number of shale gas wells developed each year since 2006 was not able to be identified. However, the decline in the number of active natural gas drilling rigs over the last few years indicates a decline in the number of shale gas wells that are drilled annually. The weekly natural gas rig count has decreased nearly four-fold since early 2007, from approximately 1,600 active rigs to 400 active rigs (EIA, 2014).

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Published estimates of water use typically rely on operator reports. DOE (2009) noted that the volumes reported are "approximate" and come from Chesapeake Energy (Satterfield et al., 2008) and personal communications with operators. Mathis (2011) also presented Chesapeake Energy data. The GAO (2012a) cites data reported by Apache Corporation. Nicot and Scanlon (2012) cite data that the Texas Railroad Commission collects from operators.

CBM wells can also be hydraulically fractured but use significantly less water than shale wells. Published reports indicate that a hydraulic fracturing treatment in a CBM well can use 50,000–350,000 gal of fluids and 75,000–350,000 pounds of sand proppant. Operator data suggests that the maximum average injection volume is 150,000 gal/well and the median volume of 57,500 gal/well (EPA, 2004).

Mielke et al. (2010) summarized the water intensity of various energy sources (see Exhibit 4-2). Natural gas is among the most water-efficient resources. If the amount of water used for shale gas production seems high, it is still less water-intense than the production of many other sources of energy, or the amount of water needed to produce an amount of energy, typically expressed in gal/MM British thermal units (Btu).

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Exhibit 4-2. Ranges of water intensity of energy sources

Energy Source	Range in Water Intensity (gal/MMBtu)
Conventional Natural Gas	~0
Shale Gas	0.6–1.8
Coal (no slurry transport)	2–8
Nuclear (uranium at plant)	8–14
Conventional Oil	1.4–62
Oil Shale Petroleum (mining)	7.2–38
Oil Sands Petroleum (in situ)	9.4–16
Synfuel (coal gasification)	11–26
Coal (slurry transport)	13–32
Oil Sands Petroleum (mining)	14–33
Synfuel (coal Fischer-Tropsch)	41–60
Enhanced Oil Recovery	21–2,500
Fuel Ethanol (irrigated corn)	2,500–29,000

Biodiesel (irrigated soy)	13,800–60,000

Conventional natural gas production requires some water for drilling, primarily for drilling mud, and to cool and lubricate the drill bit, but otherwise may use 1–3 gal/MMBtu for processing and pipeline transport (Mielke et al., 2010). Similarly, water intensity for shale gas drilling ranges 0.1–1.0 gal/MMBtu, but hydraulic fracturing has an intensity of about 3.5 gal/MMBtu. With per-well reserves ranging 2.0–6.5 Bcf, shale gas uses 0.6–1.8 gal/MMBtu with the additional water relative to conventional production needed for hydraulic fracturing (Mielke et al., 2010).

Just as water demand varies by shale play and local conditions, the water intensity also varies by play; for example, water intensity in the Fayetteville at 1.7 gal/MMBtu and the Barnett at 1.5 gal/MMBtu) are greater than in the Marcellus (1.3 gal/MMBtu) or the Haynesville (0.8 gal/MMBtu). These differences, in part, reflect greater reserves per well in the latter two plays (Mielke et al., 2010).

In contrast to shale gas, petroleum from oil shales takes more water for mining and processing or retorting, which uses steam. Oil shales are either mined with surface retorting or undergo in situ retorting to release the oil for extraction through wells. Although data are limited due to the lack of commercial production, available estimates indicate a water intensity of oil shale mining of 7.2–38 gal/MMBtu, and 9.4–16 gal/MMBtu for in situ production (Mielke et al., 2010).

Furthermore, water use in the major shale plays represents only a small fraction of total water use in the regions surrounding the plays. Exhibit 4-3 lists the various uses for water in four representative plays, as percentages of the consumption. The Barnett Shale underlies the Dallas-Fort Worth metropolitan area. More than 80 percent of the water in the area goes to public supplies. In contrast, the Marcellus underlies both populated and industrialized areas where more than 70 percent of water is used for power generation. The Fayetteville area, underlying a rural and agricultural area in Arkansas, consumes more than 60 percent of its water for irrigation. In the Haynesville, beneath eastern Texas and western Louisiana, water is used for multiple purposes, but more than 45 percent goes to public supply. Shale gas production typically consumes less than 1 percent of total water demand, except in arid regions like the Eagle Ford where it is 3–6 percent.

Exhibit 4-3. Total water use for four major shale plays

Play	Public Supply (%)	Industry & Mining (%)	Power Generation (%)	Irrigation (%)	Livestock (%)	Shale Gas (%)	Total Water Use (B gal/yr)
Barnett[A]	82.7	4.5	3.7	6.3	2.3	0.4	133.8
Eagle Ford[B]	17	4	5	66	4	3 – 6	64.8
Fayetteville[A]	2.3	1.1	33.3	62.9	0.3	0.1	378
Haynesville[A]	45.9	27.2	13.5	8.5	4.0	0.8	90.3
Marcellus[A]	12.0	16.1	71.7	0.1	0.01	0.06	3,570
Niobrara[C]	8	4	6	82		0.01	1,280

[A] From Arthur, 2009
[B] From Chesapeake Energy, 2012a
[C] From Chesapeake Energy, 2012b

Nonetheless, water presents logistical and cost challenges to shale gas operators. IHS (2012) estimates that lifecycle water management costs, including sourcing, treatment, transport, and disposal, can account for 10 percent of the operating cost of a hypothetical well in the Marcellus.

4.1.2 Sources of Water and Environmental Impacts

Unconventional natural gas producers generally withdraw water from local surface water and groundwater sources for drilling and hydraulic fracturing (DOE, 2009). So, while production uses a relatively small fraction of all local water withdrawals, to water availability have been cited as a concern, as well as the longer-term prospect for water supplies in some areas.

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Water withdrawals from surface water sources like streams and rivers can decrease downstream flows, which can render these sources more susceptible to changes in temperatures. Reduced in-stream flows can damage riparian vegetation and affect water availability for wildlife. Water withdrawals from shallow aquifers can affect these resources by lowering water levels and reducing flows to connected springs and streams, compounding the effects on surface water bodies. Deeper aquifers are also susceptible to longer-term effects on groundwater flow because recharge to deeper aquifers by precipitation takes longer. Surface water and groundwater withdrawals can also impact the amount of water available for other uses, including potable water supplies. Freshwater is a limited resource in arid and semiarid areas where expanding population and shifting patterns in land use place additional demands on water supplies. Prolonged drought conditions and weather projections associated with warming climates may exacerbate the future availability of water in some parts of the country (GAO, 2012a).

Water demand for unconventional natural gas production is not confined to shale gas and hydraulic fracturing. Gas production from CBM formations poses risks to aquifers as water in the coal bed is removed to lower reservoir pressures and induces CH_4 to desorb water from the coal. According to the USGS, dewatering CBD formations in the Powder River Basin in Wyoming can lower the groundwater table and reduce water available for other uses, such as livestock and irrigation (GAO, 2012a).

Water rights and supplies, which are typically regulated at the state level, reflect the greater general availability of water in the eastern United States. Historical trends in water use have created doctrinal differences in water laws so that east of the Mississippi River, where water tends to be more plentiful, states apply a riparian doctrine, where a water user who owns land adjacent to a water body has a right to make reasonable use of that water. In the West, where water can be scarcer, states apply a doctrine of prior appropriation, where a water user's reasonable and beneficial use of water remains subject to state permits that are generally issued on a first-come, first-served basis (CRS, 2009). In some states, water rights are allocated according to water budgets for individual basins or watersheds, as determined by a state hydrologist or water authority.

4.1.3 Shale Play Water Supply Examples

Case studies of the larger and more active shale gas plays provide a geographically distributed overview of the water demand and supply issues noted in the literature. General properties of the shales discussed are shown on Exhibit 4-4.

Exhibit 4-4. Properties of shale plays

Formation	Age	Depth (ft)	Thickness (ft)	Area (mi^2)	Location
Barnett Shale	Mississippian	6,500–8,500	100–600	18,720	Texas
Eagle Ford Shale	Cretaceous	4,000–12,000	250	20,000	Texas
Fayetteville Shale	Mississippian	1,000–7,000	20–200	9,000	Oklahoma and Arkansas
Haynesville Shale	Jurassic	10,500–13,500	200–300	9000	Texas and Louisiana
Marcellus Shale	Devonian	4,000–8,000	50–200	95,000	New York, Pennsylvania, West Virginia, Maryland, Virginia, Ohio

4.1.3.1 Barnett Shale

The Barnett Shale is a Mississippian-age shale that occurs at depths of 6,500–8,500 feet and thicknesses of 100–600 feet in the Fort Worth Basin in northcentral Texas (DOE, 2009). The Barnett covers 48,000 square kilometers (km^2) and underlies 20 counties, including the Dallas-Fort Worth metropolitan area. However, production from the Barnett comes primarily from the six counties surrounding Fort Worth (Wise, Denton, Parker, Tarrant, Hood, and Johnson) (Galusky, 2009).

Nicot and Scanlon (2012) quantified water use in the three Texas plays (i.e., Barnett, Eagle Ford, and Haynesville) based on operator data submitted to the Texas Railroad Commission. With more than 14,900 wells as of June 2011, water use per well ranges 0.75–5.5 MM gal, while median water use per horizontal well is 2.8 MM gal.

In 2007, 59 percent of the water used for natural gas production in the Barnett region came from surface water, 41 percent from groundwater, and less than 1 percent from reuse and recycling, which was projected to require less than 1 percent of regional surface water supplies and less than 10 percent of groundwater (Galusky, 2007). Public water supply in the Dallas-Fort Worth metropolitan area is the largest user, making up almost 83 percent of total demand in the area (Arthur, 2009).

A combination of growing population, drought conditions, and natural gas production raised concerns about the sustainability of local groundwater resources (Bené et al., 2006). The area has depended on the Trinity and Woodbine aquifers for more than a century, and this has resulted in declining water levels. As pressure on these aquifers has increased, additional surface water resources have been developed. In 2006, local natural gas producers formed the Barnett Shale Water Conservation and Management Committee, who have made it their mission to develop best management practices for water use.

Between April 2006 and November 2013, the Barnett Shale Water Conservation and Management Committee released at least 17 reports on water management, recovery and reuse, and alternative sources. One of their first initiatives was to commission a study on present and projected water use (Galusky, 2007), including projections published by the Texas Water Development Board (TWDB) (Bené et al., 2006). Bené et al. (2006) note that water demand projections depend on population growth estimates, while demand for other uses, including shale gas projection, are driven by economic assumptions. They projected growth of total water use in the area from about 1.0 billion (B) barrels (bbl) (423.6 B gal) per year in 2000 to 16.3 B bbl (684.3 B gal) per year in 2025, a 62 percent increase. They conclude that projections of groundwater use are regionally sustainable, but that continued development will have localized impacts. Further demands on the western parts of the Trinity aquifer in response to population growth, the Trinity aquifer may not be a reliable, long-term source of water for all users. Additional sources and distribution infrastructure could become necessary.

Galusky (2009) revisited his original assessment in the wake of declining natural gas prices in 2008–2009, as the number of well completions in the Barnett dropped by more than half in 2009, to fewer than 1,500 from about 3,000 in 2008. The previous forecasts (Galusky, 2007; Bené et al., 2006) indicated that the fraction of total freshwater from all sources would be less than 2 percent over the course of drilling the Barnett Shale. Galusky (2009) concluded that water use for Barnett Shale gas production may be less than 1.5 percent of regional supplies during periods of peak demand. Nicot and Scanlon (2012) also concluded that water use for shale gas production remains comparatively minor (less than 1 percent) at the regional and state levels, relative to irrigation (56 percent of state-wide water use) and municipal supplies (26 percent state-wide). However, they note that shale gas does consume a much higher percentage of localized water use. In some counties within the Barnett region, shale gas production uses more than 40 percent of groundwater, and as much as 29 percent of total net water use. Projected net water use in some counties could reach as much as 40 percent of the total during peak production years.

4.1.3.2 Eagle Ford Shale

The Eagle Ford Shale is a Cretaceous age formation that trends in an arc parallel to the Texas Gulf Coast from the Mexican border into east Texas, about 50 miles wide and 400 miles long with an average thickness of 250 feet at a depth of approximately 4,000–12,000 feet. It underlies 25 mainly rural counties, passing south of San Antonio and ending west of Houston. The major uses for water in the region are irrigation (66 percent) and public supply (17 percent). Water for shale gas production consumes 3–6 percent of the total water use; the primary sources are groundwater from the Carrizo-Wilcox aquifer in the northern portion of the play, and the Gulf Coast Aquifer to the south (Jester, 2013).

"Water availability" is defined by the TWDB (2012) as "how much water would be available if there were no legal or infrastructure limitations." In contrast to water availability, the TWDB (2012) defines "water supply" as the amount of water that is provided by existing wells, pipelines, and other infrastructure. The TWDB (2012) projects that water availability from the Carrizo-Wilcox aquifer will decline slightly, by about 1 percent, between 2010 and 2060; water availability from the Gulf Coast aquifer will decline by 15 percent over the same period, mainly due to restrictions on withdrawals to prevent land surface subsidence. Despite the declines in water availability from the Carrizo-Wilcox and Gulf Coast aquifers, the TWDB (2012) projections show that the water available from these aquifers will exceed the water supply capacity within the Eagle Ford region through 2060.

In 2010, the mining sector, which includes natural gas wells, accounted for 1.6 percent of Texas's water demand. The TWDB (2012) projects that this demand will be 1.3 percent of state water demand in 2060. Irrigation and municipal use account for most of the total water used in Texas. In 2010, irrigation and municipal users accounted for 56 and 27 percent, respectively, of state water demand. The TWBD (2012) projects that in 2060, irrigation and municipal water demand will each represent a 38 percent share of state water use (or, in total, 76 percent of state water use).

The Eagle Ford Task Force, appointed by the Texas Railroad Commission, evaluated data on water usage in the Eagle Ford region and concluded that the Carrizo Wilcox Aquifer contains enough water to support continued oil and gas development. Groundwater supplies about 90 percent of the water; oil and gas production, among other mining activities, will consume about 1.5 percent of total water usage in 2060. Water use for hydraulic fracturing is forecast to increase for about the next ten years to about 271 MM bbl (11.4 B gal) per year, and then decline as water recycling technologies improve (Porter, 2013).

Nicot and Scanlon (2012) quantified net water use for shale gas production using data from Texas, which is the dominant producer of shale gas in the United States. Water use in the Eagle Ford play is increasing rapidly; cumulative use (2008–mid-2011) has been 11.4 MM bbl (4.8 B gal). Further, the authors point to counties where projected local use represents a very high proportion of total water use. Projected net water use for shale gas production in peak years could consume more than 30 percent of net water use (DeWitt County: 35 percent; Dimmit County: 55 percent; and Karnes County: 39 percent). In LaSalle County, net water usage may climb as high as 89 percent of net water use, relative to 2008 total net water use. Potential impacts are primarily in competition with other users for surface water resources, which are sensitive to public supplies for increasing populations and cyclic periods of wetter and drier weather. Stress to groundwater supplies shows that impacts to surface water features like springs and streamflows and, in some cases, land subsidence (Nicot and Scanlon, 2012).

4.1.3.3 Fayetteville Shale

The Fayetteville Shale is a Mississippian age formation that straddles approximately 9,000 square miles (mi^2) of eastern Oklahoma and northern Arkansas at depths of 1,000–7,000 feet with a pay zone thickness of 20–200 feet (DOE, 2009). Pay zones are areas within a shale gas formation that, due to lithologic or fracturing differences, tend to produce more gas or produce gas more economically. Total water use in the region in 2005 was 31.9 B bbl (1.34 trillion [T] gal). Irrigation accounts for 62.9 percent of water use in the region and power generation another 33.3 percent. Shale gas production accounts for less than 1 percent of water use (Arthur, 2009).

Veil (2011) calculated the total water demand for natural gas production from the Fayetteville based on historical drilling records and estimates of water consumption per well. A high-production scenario consumes an annual volume of 4.1–5.8 B gal/year. Assuming drilling and water use are distributed evenly through the year, this translates to 11.2–15.8 MM gal/day, less than one percent of total state-wide water use in Arkansas. Veil concluded that there is sufficient water available to support natural gas development but noted that not all sources of surface water will be sufficient, nor that water should be withdrawn at the same rates through the year. Veil recommends that gas producers plan and store water during wet periods to ensure its availability when needed.

4.1.3.4 Haynesville Shale

The Haynesville Shale (also called the Haynesville/Bossier) is a Jurassic-aged formation that underlies 9,000 mi^2 of eastern Texas and northern Louisiana at depths of 10,500–13,500 feet with an average thickness of 200–300 feet (DOE, 2009). Total water use in the Haynesville region that covers eight parishes in northwestern Louisiana and six counties in eastern Texas totals 2.15 B bbl per year (90.3 B gal). The major users are public supply (45.9 percent), industry and mining (27.2 percent), and power generation (13.5 percent). Shale gas production consumes approximately 0.8 percent (Arthur, 2009).

The Texas portion of the Haynesville used 1.7 B gal (2008–mid-2011). In 2017, the projected peak production year, water demand could exceed 136 percent of total county water use for San Augustine County, Texas, 55 percent in Shelby County, and 30 percent in Panola County. Greater precipitation in the Haynesville region than in the Eagle Ford makes surface water resources more abundant but use for shale gas production can impact local streamflows. Similarly, groundwater resources remain readily available, but future conflicts with other users, including public supply and industrial users are possible (Nicot and Scanlon, 2012).

4.1.3.5 Marcellus Shale

The Marcellus Shale is a Middle Devonian-age formation that sprawls across 95,000 mi^2, underlying parts of six states, including 10 counties in southern New York, 32 counties in central Pennsylvania, 29 counties in northern West Virginia, five counties in western Maryland and Virginia, and three counties in eastern Ohio. The Marcellus is 50–200 feet thick at depths of 4,000–8,000 feet (DOE, 2009). Total annual water use in the region is 85 B bbl (3.75 T gal). The major consumers are power generation (71.7 percent), industrial and mining (16.1 percent), and public supply (12.0 percent) (Arthur, 2009). Shale gas production consumes 0.19 percent (Groat and Grimshaw, 2012).

Representative of the Marcellus region, Pennsylvania receives more than 40 inches per year in annual precipitation and has abundant supplies of water with more than 1.9 T bbl (80 T gal) as groundwater, and 58.1 B bbl (2.5 T gal) in surface waters. Despite the size of the groundwater resource, groundwater withdrawals make up just 7 percent of supply, and surface water withdrawal accounts for more than 9 percent of the annual total. As an indicator of water supply for shale gas production, during 2008–2010, water for hydraulic fracturing in the Susquehanna River Basin in central Pennsylvania came from surface water sources (71 percent) and municipal supplies (29 percent) (Abdala and Drohan, 2010).

Despite the ease of water availability in the Marcellus region, water resources agencies and citizens in the Marcellus region have expressed concerns over the local availability of water supplies for natural gas production. Hydraulic fracturing may need up to 3 MM gal of water per treatment and, under drought conditions or in areas with stressed water supplies, adequate supplies for drilling and fracturing could be difficult. In addition to impacting local water resources, concerns include watershed degradation from heavy equipment movement on rural roads, and proper methods for disposing of potentially contaminated fluids from the shale gas wells (Soeder and Kappel, 2009).

4.1.4 Potential Alternatives to Freshwater Use

Increasing demand for water for drilling and hydraulic fracturing shale gas plays has driven operators to seek supplemental sources of water, and alternatives to local freshwater sources. Potential alternative sources include industrial wastewater, water treatment plant outflows, abandoned mine waters, saline groundwater, and reuse of produced waters.

Water use for shale gas in Texas (Barnett, Eagle Ford, and Haynesville) is less than 1 percent of statewide withdrawals; however, local impacts vary with water availability and competing demands. Projections of cumulative net water use during the next 50 years for all plays total about 27.4 B bbl (1.15 T gal), peaking at 9.1 B bbl (38.3 B gal) in the mid-2020s and decreasing to 23 Mm^3 [6 B gal] in 2060. The authors note that current freshwater use may shift to brackish water to reduce competition with other users.

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Hayes and Severin (2012) report on an investigation of alternative sources of water in the Barnett that analyzed three potential sources: treated wastewater outfalls, small bodies of surface water outside state regulation, and small groundwater sources outside the main Trinity aquifer. Their results indicate that all three of these sources are susceptible to drought conditions, and that such fragmented sources involve dispersed ownership and increased costs to gather these waters.

One alternative source of water is seasonal changes in river flow; states and operators capture water when surface water flows are greatest (DOE, 2009). This echoes a recommendation by Veil (2011) to operators in the Fayetteville to store water during wet periods to ensure its availability during drier periods. However, this requires operators to use or develop places to store water and adds costs for the collection and storage.

Drilling with compressed air offers an alternative to drilling with fluids, due to the increased cost savings from both reduction in mud costs and the shortened drilling times as a result of air-based drilling. The air, like drilling mud, functions to lubricate, cool the bit, and remove cuttings. Air drilling is generally limited to low pressure formations, such as the Marcellus Shale in New York (DOE, 2009).

One of the preferred options is the reuse of produced water from prior hydraulic fracturing jobs. Mantell (2011) describes three factors that control the feasibility of reuse:

- *Quantity* of water produced, including the initial volumes of flowback water
- *Duration* of production and declines over time

- *Continuity* to keep tanks and trucks moving to increase efficiency

The Barnett, Fayetteville, and Marcellus all produce substantial volumes of water, starting with 500,000–600,000 gal/well in the first ten days, or enough to meet 10–15 percent of the total water needed for a new well. The Haynesville produces less water, typically 250,000 gal in the first ten days, or about 5 percent of the water for the next well (Mantell, 2011).

The treatment of produced water is discussed in Section 4.2.3 and Section 4.2.4.2.

4.2 Potential Impacts to Water Quality

The GAO reviewed studies indicating that shale gas development can pose risks to water quality as a result of erosion from ground disturbances, spills and releases of chemicals and other fluids, or underground migration of gases and chemicals. Spilled, leaked, or released chemicals or wastes can flow into surface waters or infiltrate into groundwaters to contaminate subsurface soils and aquifers (GAO, 2012a).

Vengosh et al. (2013) describe three potential risks to the quality of U.S. water resources: 1) contamination of shallow aquifers, primarily due to inadequate well construction; 2) hydraulic pathways connecting deep gas-bearing formations with shallower aquifers; and 3) inadequate disposal of produced and flowback waters.

EPA (2013) distinguishes four stages during hydraulic fracturing water cycle where the use of water and hydraulic fracturing chemicals could lead to possible impacts on drinking water quality:

- *Chemical Mixing*: Surface spills of hydraulic fracturing fluids on or near well pads and stormwater runoff can impact surface and groundwater resources.
- *Well Injection*: Fluid injection and fracturing processes can result in loss and migration of fluids in the subsurface.
- *Flowback and Produced Water*: Surface spills of flowback and produced water on or near well pads can impact surface and groundwater resources.
- *Wastewater Management and Disposal*: Inadequate management and treatment during wastewater transport and treatment or disposal can impact surface and groundwater resources.

These four stages occur in two interconnected environments: 1) the surface where spills during chemical mixing and wastewater management pose potential risks to surface waters and habitats, and 2) groundwaters. In the subsurface, water and chemicals can potentially leak along the well bore, propagating fractures, and existing pathways and fracture networks into shallower formations, including aquifers. Exhibit 4-5 illustrates these four stages in the use of water for hydraulic fracturing.

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Commented [MM92R91]: Avner Vengosh, Nathaniel Warner, Robert Jackson, Tom Darrah, 2013, Surface Water and Stray Gas Shallow Aquifer Contamination, https://www.epa.gov/sites/default/files/2013-08/documents/vengosh_surface_water_and_stray_gas_shallow_aquifer_contamination.pdf

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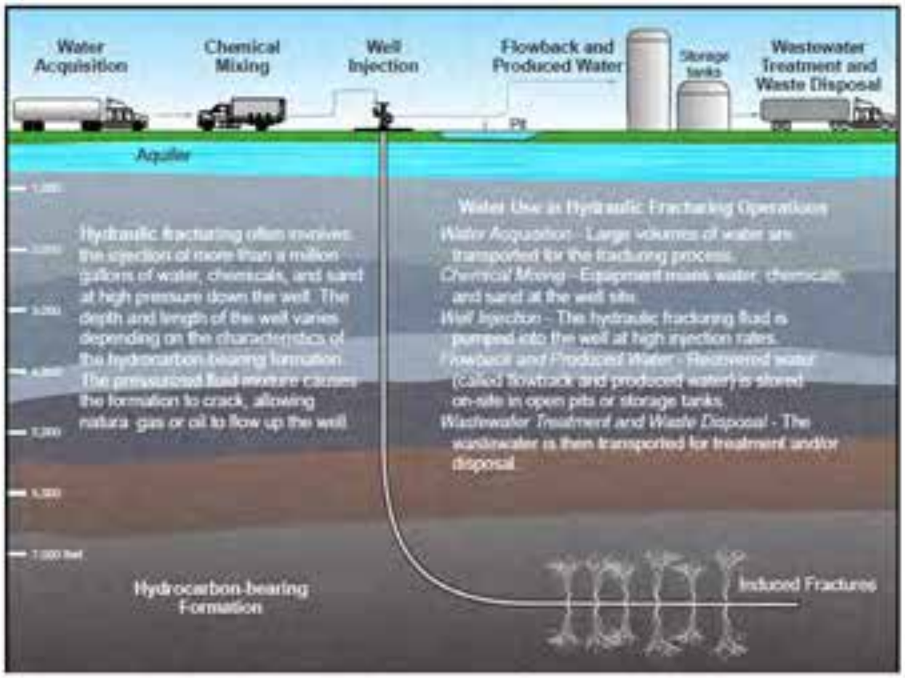
Exhibit 4-5. Water use in hydraulic fracturing operations



4.2.1 Chemical Mixing

Large quantities of fluids are essential to the drilling process. Drilling fluids circulate cuttings (rock chips produced during drilling, much like sawdust from drilling into wood) to clear the borehole as the drill advances, cool and lubricate the drill bit, stabilize the wellbore to prevent caving in, and control borehole fluid pressures. Drillers typically use lined surface pits or tanks to store water and drilling fluids (DOE, 2009). Shale gas drilling poses potential risks to water quality from spills or releases of chemicals and wastes resulting from tank ruptures, blowouts, equipment, or impoundment failures, overfills, vandalism, accidents, ground fires, operational errors, or stormwater runoff (GAO, 2012a; The Horinko Group, 2012).

EPA describes four key properties that fracturing fluids should possess:

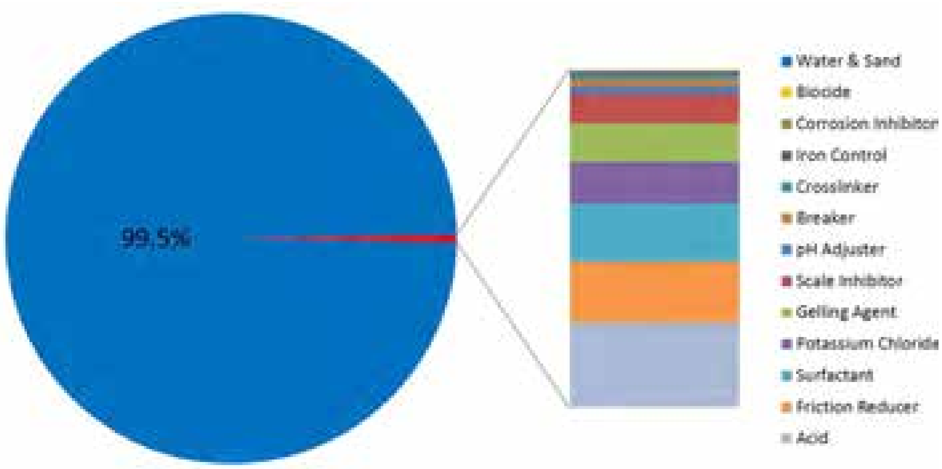
1. *Viscosity*: high enough to create fractures with adequate widths
2. *Penetration*: maximize the distance fluid travel to extend fracture lengths
3. *Transport*: ability to carry large amounts of proppant into the fractures
4. *Degradation*: minimize the amount of gelling agent to make degradation (or "breaking") easier and cheaper (2004)

Hydraulic fracturing can serve multiple purposes; most generally, it is used to increase the productivity of a well, either for injection (as in disposal wells) or extraction (or oil and gas production). In addition to increasing permeabilities and fluid flow rates, fracturing can increase the amount of contact between the well and the formation and the area of drainage within the formation and can be used to manage pressure differences between the well and the formation (EPA, 2004).

4.2.1.1 Shale Gas Drilling and Fracturing Fluids

As mentioned previously, water typically makes up more than 98 percent of the fracturing fluids used for hydraulic fracturing. In addition to water, fracturing fluid consists of a proprietary mix of chemicals and other fluids, with each serving a specific, engineered purpose. Additionally, more than 1 MM pounds of proppants may be used in hydraulic fracturing a well to prop the newly created fractures open and allow formation fluids to flow into the borehole. Proppants are compression-resistant particles, originally mainly fine-grained sand but now also include aluminum or ceramic beads, sintered bauxite, and other materials (KPMG, 2012). In a representative example from a Fayetteville well, water and sand made up more than 99 percent of the volume with various chemicals making up the rest (see Exhibit 4-6) (DOE, 2009).

Exhibit 4-6. Volumetric composition of a hydraulic fracturing fluid



Each of these chemical additives serves a specific purpose, from corrosion and scale inhibitors to friction reducers. The specific compounds used for each drilling operation vary depending on local geologic and hydrologic conditions, and according to different operators. Exhibit 4-7 describes the types of compounds added to fracturing fluids and their purposes (DOE, 2009; FracFocus, 2013).

Exhibit 4-7. Fracturing fluid additives, main compounds, and purposes

Additive	Compound(s)	Purpose	Percentage of Fluid (% of volume)	
			DOE (2009)	FracFocus (2013)
Dilute Acid	Hydrochloric or muriatic acid	Helps dissolve minerals and initiate cracks in the rock	0.123	0.07
Friction Reducer	Polyacrylamide or mineral oil	Minimizes friction between fluid and pipe	0.088	0.05
Surfactant	Isopropanol	Increases the viscosity of the fracture fluid	0.085	N/A
Potassium chloride		Creates a brine carrier fluid	0.060	N/A
Gelling Agent	Guar gum or hydroxyethyl cellulose	Thickens water to suspend sand	0.056	0.5
Scale Inhibitor	Ethylene glycol	Prevents scale deposits in the pipe	0.043	0.023
pH Adjusting Agent	Sodium or potassium bicarbonate	Maintains effectiveness of other components, such as crosslinkers	0.011	N/A
Breaker	Ammonium persulfate	Allows a delayed break down of the gel polymer chains	0.01	0.02
Crosslinker	Borate salts	Maintains fluid viscosity as temperature increases	0.007	0.032
Iron Control	Citric acid	Prevents precipitation of metal oxides	0.004	0.004
Corrosion Inhibitor	N,n-dimethyl formamide	Prevents the corrosion of the pipe	0.002	0.05
Biocide	Glutaraldehyde	Eliminates bacteria in the water that produce corrosive byproducts	0.001	0.001
Oxygen Scavenger	Ammonium bisulfate	Removes oxygen from the water to protect pipe from corrosion	N/A	N/A
Clay Control	Choline chloride, sodium chloride	Minimizes permeability impairment	N/A	0.034
Water and Proppant	Proppant: silica or quartz sand	Allows fractures to remain open so gas can escape	99.51	99.2

To provide the public information about chemicals used in hydraulic fracturing, the Ground Water Protection Council and Interstate Oil and Gas Compact Commission manage a national hydraulic fracturing chemical registry called FracFocus.[h] This site also offers general information on hydraulic fracturing, chemicals, their purposes, and groundwater protection measures. While it is not an official government information system, FracFocus is being used by states for official disclosure. Colorado, Oklahoma, Louisiana, Texas, North Dakota, Montana, Mississippi,

[h] Available at www.fracfocus.org

Utah, Ohio, and Pennsylvania use FracFocus (2013) to disclose chemical use. The FracFocus website reports the average hydraulic fracturing fluid composition for U.S. shale plays, based on August 2012 data. The relative proportions of some additives have changed since the DOE (2009) shale gas primer was published, but the types of chemicals and their purposes remain essentially the same.

4.2.1.2 CBM Drilling and Fracturing Fluids

CBM formations can be fractured with a variety of fluids, including gelled fluids, foamed gels, water with potassium chloride, and acids, or a combination of these fluids. Gellants (or thickeners) are added to water to increase viscosity; the selection of gellants is based on local formation conditions. Foamed gels, typically made by adding N_2 or CO_2 as the foamant, use the bubbles in the foam to carry proppant into the fractures. Some CBM wells need no proppants, and so water, sometimes pumped from the formation itself, can be used for fracturing. Acids are used to dissolve limestone formations that overlay or are interbedded with the coal beds to increase permeabilities. Similar to the fluids used in shale gas production, other fluids can be added to these fracturing fluids to increase the efficiency and productivity of CBM wells. These additives include breakers to decrease viscosities, biocides, fluid-loss additives, friction reducers, and acid corrosion inhibitors, plus proppants (EPA, 2004).

4.2.2 Well Injection

Underground migration of fluids, during and after hydraulic fracturing, poses a risk of contamination to groundwater quality by loss of drilling and fracturing fluids and migration of CH_4 or saline fluids from the target formation.

4.2.2.1 Loss of Drilling and Fracturing Fluids

The GAO (2012b) identified three primary pathways through which drilling and fracturing fluids can migrate through the subsurface and reach groundwater aquifers:

1. *Inadequate or Improper Casing and Cementing*: The well must be isolated with casing and cement to prevent gas or other fluids from contaminating aquifers. Pathways can be created by inadequate depth to casing, inadequate cement in the space around the casing, or cement that degrades under borehole conditions.
2. *Existing Fractures, Faults, and Abandoned Wells*: Drilling and fracturing can create connections with existing fractures or faults, or improperly plugged and abandoned wells, allowing gas and contaminants to migrate through the subsurface.
3. *Fracture Growth*: Fractures induced by hydraulic fracturing can propagate out of the production zone, allowing contaminants to reach groundwater in an aquifer.

Groundwater aquifers used as sources of drinking water typically occur at much shallower depths than the shale formations that produce natural gas. The primary barriers to subsurface contamination are proper siting, drilling, and completion of boreholes to ensure seals between the borehole and the rock outside the production zone, and the vertical separation between the geologic formations that produce shale gas and the shallower aquifers normally used as sources of drinking water.

Current well construction practices include multiple layers of protective steel casing and cement that protect freshwater aquifers and ensure that the producing zone is isolated from overlying formations. The casing is set while the well is being drilled and then, before drilling any deeper, the new casing is cemented to seal the gap between the casing and the formations being drilled through. Each string of casing then serves to protect the subsurface environment by separating the drilling fluids inside and formation fluids outside of the casing. Operators can check and repair the integrity of the casing and the cement bonding during and after drilling (DOE, 2009).

In addition to the engineered barriers in the casings and cements, the rock formations themselves act as natural barriers that contain natural gas and associated fluids in the target formation. Effective seals are what contain oil and gas and allow it to accumulate into economically extractable resources, just as is the case with aquifer formations that hold economic quantities of freshwater. In fact, the technology developments that have allowed extraction of natural gas from shale formations involve ways to release gas otherwise trapped in these formations for millions of years (DOE, 2009).

In some shale plays, the vertical separation between the top of the shale formation and the deepest part of the aquifer can be more than two miles, reducing the likelihood of interconnections through the subsurface. Exhibit 4-8 lists representative separation distances for some of the major shale plays (GAO, 2012a and DOE, 2009).

Exhibit 4-8. Vertical separation distances for groundwater over major shale plays

Shale Play	Depth to Base of Treatable Water (ft)	Separation Distance (ft)	Depth to Shale (ft)	Net Thickness of Shale (ft)
Barnett	1,200	5,300–7,300	6,500–8,500	100–600
Fayetteville	500	500–6,500	1,000–7,000	20–200
Haynesville	400	10,100–13,100	10,500–13,500	200–300
Marcellus	850	2,125–7,650	4,000–8,500	50–200
Woodford	400	5,600–10,600	6,000–11,000	120–220
Antrim	300	300–1,900	600–2,200	70–120
New Albany	400	100–1,600	500–2,000	50–100

In Chapter 1 – Background, Exhibit 1-1 illustrates the major components of the shale gas well construction process. **Error! Not a valid bookmark self-reference.** illustrates the multiple barriers created by the combination of multiple sets of casing and cement.

Exhibit 4-9. Components of the well construction process

Unlike shale gas plays, CBM formations tend to be shallower, and the coal beds can lie within underground sources of drinking water (EPA, 2004). For the three most productive CBM basins, coal seams in the San Juan Basin are found at 600–3,500 feet below ground, Powder River Basin seams lie at 450–6,500 feet below ground, and Black Warrior Basin seams occur at 350–2,500 feet. Because they are shallower than other gas wells, CBM wells can sometimes be drilled with water well equipment rather than the larger and more complex equipment needed for conventional and shale gas wells (EPA, 2010).

Two types of well completions are used for CBM production, open-hole and cased. No lining material is installed in open-hole completions so that the gas can seep into the well bore and be brought to the surface. Cased completions are lined and then the casings are perforated in producing zones to allow the gas to flow into the well. Open-hole completions are used more often for CBM wells than conventional production, especially in the Powder River Basin (EPA, 2010).

In evaluating reports from citizens about water quality issues, EPA found no confirmed evidence that drinking water wells had been contaminated by hydraulic fracturing fluid injection in CBM wells (EPA, 2004). EPA (2010) noted that future CBM development may rely on deeper, thinner, tighter, and lower-rank coals, any of which would increase production costs, and that tighter coals could require hydraulic fracturing to produce gas economically. However, in terms of environmental impacts, EPA subsequently focused on the discharge of produced water (EPA, 2010).

4.2.2.2 *Migration of CH_4 and Formation Fluids*

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A December 2008 explosion in a house in Geauga County, Ohio, was investigated by the Ohio Department of Natural Resources (ODNR) (2008). Local responders quickly recognized that natural gas was leaking into houses through water wells. The gas-bearing formation in the area is the Silurian "Clinton" sandstone, the local term for a sequence of inter-bedded sandstones, siltstones, and shales. The ODNR determined that deep, high-pressure natural gas had over-pressurized the annulus of the English No. 1 Well, allowing gas to migrate from the well annulus into natural fractures in the bedrock below the cemented surface casing. This gas then migrated upward through fractures into the overlying aquifers and escaped from the aquifer through local water wells. The ODNR identified three primary contributing factors: inadequate cement of the production casing, hydraulic fracturing of the well with the inadequate cement, and shutting-in the well for 31 days after the fracturing, which allowed pressure to build. The ODNR determined that 22 domestic and one public water supply had been contaminated by natural gas charging from the English No. 1 Well. The data indicated that groundwater had not been contaminated by brine, crude oil, or fracturing fluids.

In January 2008, the ODNR announced implementation of new permit conditions for northeastern Ohio. CH_4 and formation fluids can migrate naturally within the subsurface, even without disturbance by drilling or hydraulic fracturing. Warner et al. (2012) present evidence that pathways unrelated to drilling or hydraulic fracturing can exist between deep formations and overlying aquifers. Geochemical data and isotopic ratios indicate that mixing between shallow groundwater and brines from deeper formations can cause salinization of groundwater along naturally occurring pathways.

In the Fayetteville region, Kresse et al. (2012) sampled and analyzed 127 domestic water wells to describe the general quality and geochemistry, and to investigate the potential impacts of gas-production on shallow groundwater in the area. Water-quality analyses from this study were compared to pre-development shallow groundwater quality samples. Among the results, the authors found higher chloride, major ion, and trace metal concentrations in the pre-development samples. CH_4 was also detected in a subset of the post-development samples but based on carbon isotope ratios the authors concluded that CH4 had biogenic origins. The groundwater-quality data collected for this study indicated that groundwater chemistry in the shallow aquifer system in the study area, including CH_4, was a result of natural processes.

CH_4 has also been found in water wells in Pennsylvania pre-dating the advent of Marcellus Shale gas development. Breen et al. (2007) investigated occurrences of natural gas in wellwater in Pennsylvania. Gas occurrence in groundwater and accumulation in homes had become a safety concern; the investigators concluded that the weight of evidence pointed to gas from local underground storage fields as the likely origin.

In 2010 and 2011, the Center for Rural Pennsylvania analyzed water samples from private water wells located within 5,000 feet of Marcellus Shale gas wells (Boyer et al., 2012). Water from approximately 40 percent of these wells failed at least one SDWA standard, typically for coliform bacteria, turbidity, and manganese, before gas well drilling. The results also showed dissolved CH_4 in about 20 percent of water wells prior to the development of natural gas wells. Post-drilling analysis showed no significant increases in pollutants from drilling fluids and no significant increases in CH_4. There were outlier samples that exhibited high concentrations of total dissolved solids (TDS) and chloride after the nearby development of natural gas wells; Boyer et al. (2012) found no evidence linking these increased TDS and chloride concentrations to natural gas well development.

Duke University researchers studied shale gas drilling and hydraulic fracturing, and the potential effects on shallow groundwater systems near the Marcellus Shale in Pennsylvania and the Utica Shale in New York (Osborne et al., 2011). CH_4 concentrations were detected generally in 51 drinking water wells, but concentrations were higher closer to shale gas wells. A source of the contamination could not be determined, and no evidence of fracturing fluids was found in any of the samples. Isotopic data for CH_4 detected in shallow groundwater were consistent with deeper sources such as the Marcellus and Utica and matched the natural gas geochemistry from nearby gas wells. Lower-concentration samples from non-active sites had isotopic signatures reflecting a more biogenic or mixed biogenic-thermogenic source. The authors found no evidence of contamination of drinking water samples with deep saline brines or fracturing fluids.

Osborne et al. (2011) describe three possible sources for the CH_4 they detected. The first is physical displacement of gas-rich solutions from shale formations, which is unlikely due to the 1–2 km of strata above the shale. The second is leakage along gas well casings, with CH_4 passing laterally and vertically into existing fracture systems. The third source is the formation of new fractures, or the enlargement of existing ones, due to hydraulic fracturing, thereby increasing the interconnectivity of the fracture system. They concluded that the higher concentrations measured in shallow groundwater from active drilling areas could result from migration from a deep CH_4 source associated with drilling and hydraulic fracturing activities. In contrast, the lower-level concentrations in groundwater aquifers observed in the non-active areas are likely a natural phenomenon. More recently, Jackson et al. (2013) examined concentrations of natural gas and isotopic ratios in drinking water wells in northeastern Pennsylvania and found CH_4 in 82 percent of 141 wells. Concentrations averaged six times higher in wells less than 1 km from natural gas wells. These authors concluded that isotopic signatures, hydrocarbon ratios, and helium/CH_4 ratios indicate a Marcellus-like source in some cases, suggesting that some water wells within 1 km of gas wells are contaminated by stray gases.

Molofsky et al. (2013) tested 1,701 water wells in northeastern Pennsylvania and found that CH_4 was ubiquitous in local groundwater. Higher concentrations were found in valleys than in upland areas and particular water chemistries, which correlates more with topography and hydrogeology than Marcellus Shale gas extraction. The authors concluded that CH_4

concentrations in water wells in this area could be explained without migration of Marcellus shale gas through fractures.

Vengosh et al. (2013) review results from Osborne et al. (2011) and Molofsky et al. (2011) regarding the sources of possible CH_4 contamination in drinking water wells in the Marcellus. Osborne et al. (2011) found that elevated levels of CH_4 correlated in water wells within 1 km of natural gas wells. Isotopic and geochemical signatures indicated that high levels of CH_4 contamination in the closer wells had thermogenic sources rather than the mixed and biogenic sources in wells farther away. New noble gas data corroborate the conclusion that CH_4 in the closer wells had a thermogenic origin. Vengosh et al. (2013) report that the most likely pathway for the CH_4 was leaking through inadequate cement on casing, or through well annulus from intermediate formations.

4.2.3 Flowback and Produced Water

At least 56 MM bbl (2.4 B gal) of water is produced per-day nationwide as a byproduct of drilling oil and gas wells (GAO, 2012b). The five states with the greatest produced water volumes in 2007 were Texas, California, Wyoming, Oklahoma, and Kansas. Texas alone accounted for more than 7.3 B bbl, contributing to 35 percent of the total produced water by volume. Produced water from unconventional natural gas production is not necessarily a major contributor to the total volumes of nationally produced water from oil and gas production. Of the top 10 states for produced water, only five have major unconventional gas play (Clark and Veil, 2009). However, the volumes of produced water from unconventional gas production can present local and regional challenges.

4.2.3.1 Flowback Water

In the days and weeks following the injection of the 2–6 MM gal of water, chemicals, and proppants used to hydraulically fracture a shale gas well, a fraction of this water is recovered as flowback water, while the remainder is temporarily lost into the formation. Estimates vary on what fraction of injected fluids return to the surface. The GAO (2012a) reports that 30–70 percent of the original fluid injected returns to the surface; IHS (2012) puts the figure at 20–80 percent; the CRS (2009) reports that this figure can range 60–80 percent.

Gregory et al. (2011) tabulates a typical range of concentrations for some of the common constituents of flowback water from the Marcellus Shale (Exhibit 4-10). The “low” concentrations were measured in early flowback from one well; “medium” concentrations were from late flowback from the same well; the “high” concentrations were measured in several wells with similar TDS concentrations.

Exhibit 4-10. Typical concentrations for common constituents in flowback water

Constituent	Low (mg/L)	Medium (mg/L)	High (mg/L)
TDS	66,000	150,000	261,000
TSS	27	380	3,200
Hardness (as calcium carbonate)	9,100	29,000	55,000
Alkalinity (calcium carbonate)	200	200	1,100
Chloride	32,000	76,000	148,000
Sulfate	ND	7	500
Sodium	18,000	33,000	44,000
Calcium (total)	3,000	9,800	31,000
Strontium (total)	1,400	2,100	6,800
Barium (total)	2,300	3,300	4,700
Bromide	720	1,200	1,600
Iron (total)	25	48	55
Manganese (total)	3	7	7
Oil and grease	10	18	260
Total Radioactivity	ND	ND	ND

ND = Not detected

The drillers may temporarily retain the flowback and brine in lined retention ponds before reuse or disposal; the pits must be reclaimed when operations end at that site. The well operator must then separate, treat, and dispose of the natural brine co-produced with the gas.

Flowback water can make treatment more difficult because it contains extremely high amounts of TDS. The longer the fracturing fluid remains below ground in contact with the shale, the higher the TDS, metals, and naturally occurring radioactivity it can pick up from the formation (Abdalla et al., 2012). The additives for hydraulic fracturing in a 3 MM gal fracturing job would yield about 15,000 gal of chemicals in the waste or about 0.5 percent of the total volume (CRS, 2009).

4.2.3.2 Produced Water

Once the well begins to produce natural gas, it also yields formation fluids called produced water (IHS, 2012). Because produced water has been held in hydrocarbon-bearing formations, the fluids found in oil and gas bearing formations typically include a variety of hydrocarbons and water or saltwater brines. The properties of produced water vary considerably depending on the geologic formation, the location of the field, and the types of hydrocarbons being produced. Produced water volumes and chemical properties can also vary throughout the producing lifetime of a formation (Clark and Veil, 2009).

The quality of produced water is typically poor, and generally cannot be used for other purposes without treatment. The GAO (2012b) described the range of possible contaminants that includes, but is not limited to the following:

- *Salts*: chlorides, bromides, and sulfides of calcium, magnesium, and sodium
- *Metals*: barium, manganese, iron, and strontium
- *Organics*: oil, grease, and dissolved organics
- *Naturally Occurring Radioactive Materials*: including radium and radon
- *Production Chemicals*: including those used for hydraulic fracturing

CBM wells produce more water than other forms of unconventional natural gas wells. Water pressure in the coal seam helps keep the gas attached to the coal; lowering the pressure by pumping out water helps release the gas (Guerra et al., 2011). Water production from CBM wells normally starts at high volumes, but then falls as the coal seam is depressurized. Produced water from CBM wells varies in quality from very good (meeting state and federal drinking water standards) to very high in TDS with concentrations up to 180,000 parts per million, which is not suitable for reuse (ALL Consulting, 2003). Exhibit 4-11 tabulates representative produced water quality data for the San Juan Basin and Powder River Basin, which together represent nearly 70 percent of CBM production.

Exhibit 4-11. Chemical constituents in CBM produced waters

Constituent	San Juan Basin		Powder River Basin	
	Minimum (mg/L)	Maximum (mg/L)	Minimum (mg/L)	Maximum (mg/L)
TDS	180	171,000	244	8,000
Barium	0.7	63	0.06	2
Calcium	0	228	5	200
Chloride	0	2,350	3	119
Iron	0	228	0.03	11
Magnesium	0	90	1	52
Potassium	0.6	770	2	20
Sodium	19	7,130	89	800
Sulfate	0	2,300	0.01	1,170

The treatment of CBM produced water is discussed below in Section 0 (in particular, Section 4.2.4.4).

4.2.4 Wastewater Management and Disposal

The oil and gas industry applies a three-tiered approach to the management of produced water that follows a hierarchical pollution prevention approach (NPC, 2011; Veil, 2011):

- *Minimization*: mechanical and chemical alternatives to water use
- *Recycle/Re-use*: re-injection for enhanced recovery or continued hydraulic fracturing, re-use for agriculture and industry, and treatment for drinking water
- *Disposal*: underground injection, evaporation, or surface water discharge

How operators manage, treat, and dispose of produced and flowback water is mainly an economic decision made within the limits of the applicable federal and state regulations. For example, underground injection is most often the least-cost option, ranging from $0.07–1.60/bbl. Trucking costs for an injection well can significantly increase the total costs. In Texas, trucking costs can range $0.50–1.00/bbl; in Pennsylvania they can range from $4.00–8.00/bbl. Water treatment can cost between $6.35–8.50/bbl, and advanced treatment by reverse osmosis and ion exchange can cost an additional $0.20–0.60/bbl (GAO, 2012b).

The GAO (2012b) reports that other factors that influence water management options:

- *Geology*: availability of injection wells and their distances from producing wells
- *Climate*: arid climates are more favorable for evaporation from surface impoundments
- *Regulations*: federal and state regulations control the use of management methods
- *Risk Management*: legal liabilities from surface discharges and impoundments

Exhibit 4-12 outlines the main water management technologies used by each shale play (DOE, 2009).

Exhibit 4-12. Produced water management by shale gas basin

Shale Gas Basin	Water Management Technology	Availability	Comments
Barnett	Class II injection wells	Commercial & non-commercial	Disposal into Barnett and underlying Ellenberger Group
	Recycling	On-site treatment & recycling	Reuse in subsequent fracturing
Fayetteville	Class II injection wells	Non-commercial	Disposal into two injection wells owned by a producing company
	Recycling	On-site recycling	Reuse in subsequent fracturing
Haynesville	Class II injection wells	Commercial & non-commercial	N/A
Marcellus	Class II injection wells	Commercial & non-commercial	Limited use of Class II injection wells
	Treatment and discharge	Municipal and commercial treatment facilities	Primarily in Pennsylvania
	Recycling	On-site recycling	Reuse in subsequent fracturing
Woodford	Class II injection wells	Commercial	Disposal into multiple confining formations

Shale Gas Basin	Water Management Technology	Availability	Comments
	Land application	N/A	Permit required through OK Corporation Commission
	Recycling	Non-commercial	Water recycling and storage at central location
Antrim	Class II injection wells	Commercial & non-commercial	N/A
New Albany	Class II injection wells	Commercial & non-commercial	N/A

Different management methods invoke different sets of statutory and regulatory controls. For example, underground injection is regulated by EPA and the states under the SDWA, while discharges of waters are regulated under the Clean Water Act and the National Pollutions Discharge Elimination Systems. Other management practices can be regulated by state authorities (GAO, 2012b). The sections below summarize each of the common management methods.

4.2.4.1 Minimization

Options for inimizing water use available to unconventional natural gas producers mainly involve mechanical and chemical alternatives that reduce the amount of water needed for drilling and hydraulic fracturing. Down-hole mechanical blocking devices such as packers and plugs can cut the amount of water needed in the borehole during development. Other materials, like CO_2 or N_2 can be used in place of water, as can gelled fluids. However, gelled fluids can damage the formation and increase the amounts and types of chemicals used (NPC, 2011). In places like Wyoming where infrastructure, including pipelines are readily available, CO_2 has already been used for fracturing in place of water. However, substituting CO_2 for water on a larger scale (e.g., across the United States) would require large investments in infrastructure to deliver the CO_2 to drilling and fracturing sites (MIT, 2013).

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4.2.4.2 Recycle and Reuse

Shale gas producers have begun reusing produced water for hydraulic fracturing. Water is typically treated first, and then mixed with freshwater if salt concentrations remain high. For reuse to become widespread, among shale gas operators, new, low-cost treatment technologies will be needed. Re-use has become more common among shale gas producers in Pennsylvania, in part due to a change in the state's surface water discharge standards that made treatment and discharge comparatively more expensive (GAO, 2012b).

The feasibility of using produced and flowback water for shale gas production depends on the volume and quality of the re-used water. Operators benefit from larger volumes of water that stabilize the logistics of collecting, storing, and transporting the water, keeping tanks and pits in use and trucks moving. Water quality is important for reuse, particularly the TDS, mainly the salt content, and total suspended solids (TSS), or the amount of fine-grained particulate matter in the water, to control the drilling fluid chemistry and remove some of the contaminants that can return to the surface with the produced water.

Accenture (2012) divides water treatment technologies into two categories, the first for removing inorganic materials, primarily salts, and the second for organic materials, including oil and grease. The unconventional gas industry has concentrated on developing technologies to deal with the inorganic materials given the high TDS in flowback water from shale gas development. Accenture (2012) describes four types of treatment technologies available to shale gas operators:

1. *Filtration* removes suspended solids with anything from simple household water filters to more complex and efficient designs. Shale gas operators use filters with pore sizes of 0.04–3 microns.
2. *Chemical Precipitation* removes scale-forming elements like calcium, magnesium, barium, strontium, iron, manganese, and other metals. By adding chemicals and adjusting pH values, these constituents precipitate out of solution and settle out where they can be collected as sludge for disposal.
3. *Thermal-Based Technologies* remove salts from waters with very high TDS levels. By heating the water to almost the boiling point, the water vapor can be collected as distilled water or evaporated to the atmosphere. The residual solids collected as concentrated brine or crystalline salt.
4. *Membrane Filtration Technologies* have limited use in shale gas production as they are ineffective at filtering TDS concentrations greater than 35,000–45,000 parts per million. Reverse osmosis is a common membrane filtration technology.

Produced water from the Barnett is generally high in TDS, but low in TSS and moderate scaling tendency. The preferred management method is disposal by underground injection. The large volumes of produced water and the availability of Class II disposal injection wells in the Barnett region limit the reuse of water. One operator reports treating and reusing about 6 percent of the total water needed for drilling and fracturing in the Barnett (Mantell, 2010).

Fayetteville Shale produced water is generally of excellent quality for reuse, having very low TDS, low TSS, and low scaling tendency. Since TSS levels are low, very limited treatment (filtration) is needed prior to reuse. The volume of water generated is typically sufficient to justify reuse (Mantell, 2010). One operator is currently meeting approximately 6 percent of its drilling and fracturing needs in the Fayetteville with produced water reuse and has a goal of 20 percent reuse in the play (Veil, 2011). As with the Barnett, logistics and economics are the primary limiting factors that prevent higher levels of reuse in the Fayetteville (Mantell, 2010).

The Haynesville Shale produces a smaller volume of produced water initially, relative to other major plays, but it is of very poor quality. TDS levels are immediately high, TSS is high, and the produced water has high scaling tendency. The quality and volume factors combined with an adequate underground injections infrastructure make produced water reuse in the Haynesville challenging. Low produced water volumes, poor produced water quality and the associated economics have prevented successful reuse of produced water to-date in the Haynesville (Mantell, 2010).

The Marcellus Shale is ideal in terms of produced water generation in that it produces significant volumes of water during the first few weeks and then water production typically declines quickly. Marcellus produced water is good quality with moderate to high TDS, low TSS, and moderate scaling tendency. Operators manage TDS by blending previously produced water with freshwater and the TSS is managed with filtration systems. Scaling is managed through precise monitoring and testing to ensure the compatibility of the blended produced and freshwater (Mantell, 2010). The proportion of flowback water now reused in Pennsylvania is estimated to be as high as 75 percent (Abdala et al., 2012).

Veil (2010) examined the flowback and water management technologies and methods used today that are likely to continue to be used in the Marcellus region. He concluded that the region has sufficient water supplies and coordination with authorities like the Susquehanna River Basin Commission and the Delaware River Basin Commission has not become an obstacle. Marcellus operators have had some success reusing water from previous hydraulic fracturing with lower-TDS freshwaters, which would cut costs and reduce the volumes of freshwater needed.

Treatment of shale gas wastewater became an issue in Pennsylvania in 2011, where there are limited wastewater disposal options. Operators were sending wastewater to municipal wastewater treatment plants, which then treated the water and discharged it to rivers that supply drinking water populations across Pennsylvania and Maryland. The media reported concerns that these treatment plants were neither designed nor capable of treating drilling wastewaters. In March 2011, EPA (2011) wrote to environmental officials in Pennsylvania noting “variable and sometimes high concentrations of materials that may present a threat to human health and aquatic environment, including radionuclides, organic chemicals, metals and total dissolved solids” were present in the wastewater, and urged increased water quality monitoring, particularly for radionuclides. Subsequent concerns about elevated bromide levels in state waterways prompted Pennsylvania regulators to request that operators stop sending their wastewaters to municipal treatment plants that may not be prepared to treat it. According to the Marcellus Shale Coalition, Marcellus operators complied with the state’s request within two days (Williams, 2012).

4.2.4.3 Disposal

The preferred disposal method for water in the oil and gas industry is largely underground injection. In 2007, more than 98 percent of produced water from onshore wells was injected underground (Clark and Veil, 2009). EPA and states regulate this practice under the SDWA and UIC (EPA, 2013). Among the six classes of injection wells recognized by EPA, oil and gas-related wells form Class II, which includes wells for enhanced recovery, disposal, and hydrocarbon storage.

Class II injection wells are specifically designed and constructed to inject fluids into permitted zones and prevent migration of injected fluids into underground sources of drinking water. Most produced water generated onshore is used to maintain reservoir pressures and drive oil toward producing wells for enhanced oil recovery (Clark and Veil, 2009). Produced water does not need treatment before injection, but operating requirements to prevent plugging may cause water to be treated to control solids and dissolved oil, inhibit corrosion and chemical reactions, and retard microbial growth. Settling tanks, chemical additives, and filtration may also be used (GAO, 2012b).

In the Marcellus, only about 5 percent of the water used is disposed of without treatment via underground injection (Abdala et al., 2012). The current disposal practice for Marcellus Shale liquids in Pennsylvania requires processing them through wastewater treatment plants, but the effectiveness of standard wastewater treatments on these fluids is not well understood. In particular, salts and other dissolved solids in brines are not usually removed successfully by wastewater treatment, and reports of high salinity in some Appalachian rivers may be associated with the disposal of Marcellus Shale brines. Concerns in Appalachian States about the possible contamination of drinking water supply aquifers have limited the practice of re-injecting Marcellus fluids (Soeder and Kappel, 2009).

4.2.4.4 Discharge to Surface Water or Evaporation

A very small fraction, less than 1 percent, of onshore produced water is discharged to surface water bodies, generally in the western states when the TDS content is low. Treatment for surface discharge includes settling and filtration of solids, and salt removal with chemical additives. Other methods used to remove salts and other contaminants include thermal distillation, reverse osmosis (filtration), and ion exchange (only at low concentrations) (GAO, 2012b).

Surface water discharge for unconventional natural gas production is associated mainly with water produced from CBM extraction. EPA (2010) estimated that more than 47 B gal of water were produced from coal seams in 2008 and about 45 percent, or about 22 B gal, was discharged to surface waters. Currently, allowing surface water discharges is made by either state agencies or EPA regional offices, depending on the state’s permitting authority (Clark and Veil, 2009). More commonly, for example, in the Powder River Basin, produced water is held in ponds or pits for evaporation. Some of this water is used for irrigation when it does not require treatment to meet water quality standards (GAO, 2012b).

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5 INDUCED SEISMICITY

Induced seismicity is ground motion (earthquakes) caused by human activities. Earthquakes have been detected in association with oil and gas production, underground injection of wastewaters, and with hydraulic fracturing (Rubinstein and Mahani, 2015). Hydraulic fracturing involves injecting large volumes of fluids into the ground. In contrast to hydraulic fracturing, wastewater from oil and gas production, including shale gas production, is typically disposed of by being injected at relatively low pressures into extensive formations that are specifically targeted for their porosities and permeabilities to accept large volumes of fluid. Case studies from several states indicate that deep underground fluid injection can, under certain circumstances, induce seismic activity (Horton, 2012; Frolich, 2012; ODNR, 2012; Keranen et al., 2013; Hayes, 2012).

5.1 INDUCED SEISMICITY AND ENERGY TECHNOLOGIES

The term seismic activity is used to describe the vibration of mechanical energy passing through the earth, much like sound waves vibrate through the atmosphere. More than 1.4 MM earthquakes greater than magnitude 2.0 (Richter Scale) are measured world-wide each year. Most earthquakes occur naturally in response to sudden slips and shifts of large masses of rock along geologic faults. Earthquakes with magnitudes of 2.0 or less generally cannot be felt at the surface by people. Magnitudes greater than 3.0 tend to produce noticeable shaking and magnitudes greater than 5.0 can potentially cause structural damage to buildings and property.

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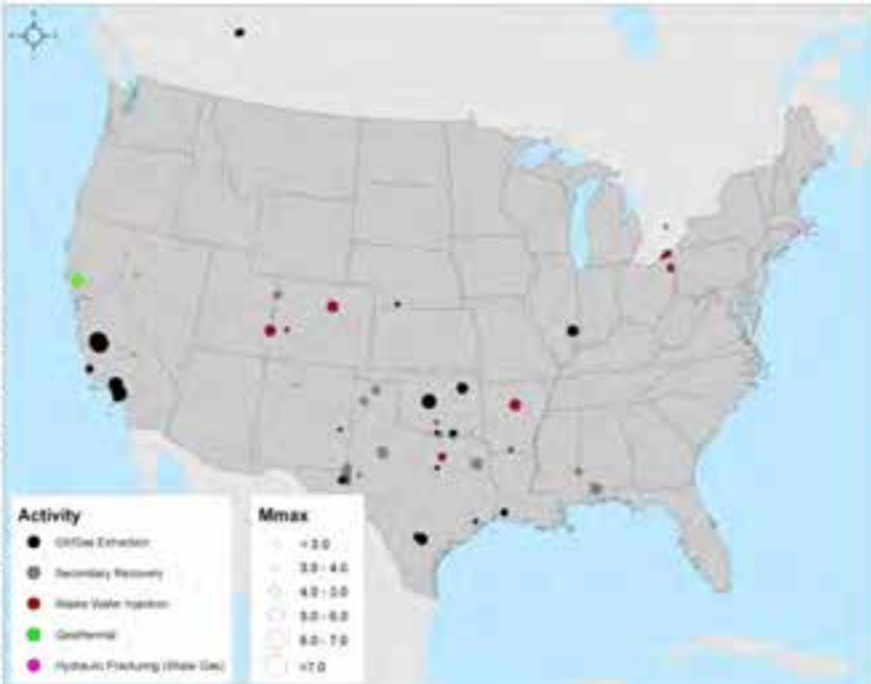
The NRC (2012) describes seismic events caused by or likely related to energy development in at least 13 states involving oil and gas extraction, secondary recovery, wastewater injection, and geothermal and hydraulic fracturing for shale gas. Exhibit 5-1 shows sites in the United States and Canada with a history of incidents of induced seismicity caused by or related to energy development operations (NRC, 2012). The reporting of small events is limited by the availability of sufficiently sensitive seismic monitoring networks. However, the NRC notes that proving human activity caused by a particular event can be difficult because such conclusions depend on local data, records of prior seismicity, and scientific literature.

Exhibit 5-1. Locations of induced seismicity associated with energy technologies



The GWPC (2013) provides an updated overview of induced seismicity in their white paper titled "Assessing and Managing Risk of Induced Seismicity by Injection," which summarizes a 2013 special technology transfer session held in Sarasota, Florida. The session focused on the risks of induced seismicity and reviewed the recent NRC (2012) case study examples of induced seismicity. The major issues and findings discussed in paper included the following (GWPC, 2013):

> In nearly all cases, the potential for felt seismicity from hydraulic fracturing is very low, although a few cases have been observed where unique conditions were present. However, these have not led to any significant surface damage. The NAS [National Academy of Sciences, NRC] report concluded that hydraulic fracturing does not pose a high risk for induced seismicity. (XXREF)
>
> Tens of thousands of disposal wells are employed each day to inject produced water and other wastewaters into formations that are not hydrocarbon bearing. Most of these injections pose a low risk of induced seismicity but given the ongoing injection and cumulative formation pressure build up over time, there is some potential that disposal wells can contribute to induced seismicity. Most wells are completed in areas and geological formations that are not likely to lead to induced seismicity, but several well-documented examples are described in this white paper where seismic activity was

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linked to disposal wells (e.g., Ohio, Arkansas, Oklahoma, and Texas). These are typically due to some geological anomalies or faults in those locations.

The GAO (2012) concluded that the energy released by hydraulic fracturing does not produce enough ground motion to be felt at the surface. However, disposal of waste fluids through underground injection (see also Chapter 4 – Water Use and Quality), which is commonly used throughout the oil and gas industry, including unconventional natural gas production, has, in some instances, been associated with perceptible earthquakes. The existing research does not establish a direct link between hydraulic fracturing and increased seismic activity, but to the extent that increased hydraulic fracturing increases the amount of water disposed of through underground injection, it could contribute to increased seismicity.

5.2 Hydraulic Fracturing for Unconventional Gas Production

Thompson (2011) outlined four differences between hydraulic fracturing and other types of potential causes of induced seismicity:

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1. *Different Type of Stress Release* – Hydraulic fracturing creates small fractures through tensile (extending) stresses where fractures spread as their walls are stretched apart whereas induced seismicity causes shear stresses that cause movement along faults.
2. *Limited Distances from the Wellbore* – Operators avoid creating fractures that propagate adjacent formations, which would waste fluids and energy outside the target formation and potentially allow gas to escape. Typically, shale gas fracturing penetrates 15 feet into the formation from the borehole and fracturing fluids on the order of 100 feet from the hole.
3. *Limited Volume of Fluid* – The amount of fluid used for hydraulic fracturing tends to be only what is needed to stimulate production.
4. *Limited Period of Time* – Hydraulic fracturing is normally completed within a period of hours or days. The operator's objective is to drill and fracture the well as efficiently as possible and pivot well operations to extracting natural gas as quickly as possible.

The seismic behavior caused by hydraulic fracturing shale gas wells is recorded and understood through microseismic monitoring. During hydraulic fracturing, very small earthquakes, or microseismic events, are created by the high-pressure injection of fluids into a target formation. The increased pore pressure causes small natural fractures in the formation to slip, causing "microearthquakes" that are measured and recorded with sensitive sensing equipment and processing algorithms. The location and magnitude of microseismicity is used by oil and gas operators to help identify the orientation and spacing of the hydraulic fractures in the formation, in addition to helping guide horizontal well directions and well spacing, and in planning subsequent fracturing treatments (Warpinski et al., 2012; NRC, 2012).

Warpinski et al. (2012) reviewed thousands of fracture treatments in six major shale basins in North America and found that the seismicity from hydraulic fracturing is small and does not create problems under normal circumstances. At least 12 incidents of induced seismicity associated with shale gas production and hydraulic fracturing have been documented worldwide, and six of these were in the United States. The other incidents occurred in the Horn River Basin in British Columbia, Canada; Blackpool, Lancashire, United Kingdom; and South Sichuan Basin, China (Schultz et al., 2020).

The first incident in the United States occurred in January 2011, when the Oklahoma Geological Survey (OGS) responded to a resident of Garvin County, in south-central Oklahoma, who reported feeling several earthquakes and observed that hydraulic fracturing operations were active nearby. The OGS found that there had been nearly 50 earthquakes ranging from 1.0–2.8 in magnitude and that 43 of the quakes were large enough to be located. The majority of the earthquakes seem to have happened within about 3.5 km of a shale gas well and had started about seven hours after the first well was hydraulically fractured. The correlation in space and time with the hydraulic fracturing suggested to Holland "that there is a possibility these earthquakes were induced by hydraulic fracturing. However, the uncertainties in the data make it impossible to say with a high degree of uncertainty whether these earthquakes were triggered by natural means or by the nearby hydraulic-fracturing operation" (Holland, 2011).

Davies et al*.* (in press) proposed three mechanisms by which the increased fluid pressure in a fault zone of hydraulic fracturing could trigger seismic events.. First, fracturing or pore fluids could enter a fault. Second, with a direct connection between the fault and the fractures, a pulse of fluid pressure could be pushed to the fault. Third, fracturing could increase fluid pressure in the fault. The fluids or fluid pressure could follow three types of pathways: directly from the borehole, through newly created fractures, or through existing fractures or faults. Thus, a borehole could intersect the fault or be some distance from it. Theoretically, these mechanisms and pathways could produce the three documented examples of seismicity "probably induced by hydraulic fracturing" (Davies et al*.*, in press).

The Energy institute at The University of Texas at Austin funded an initiative to promote fact-based shale gas policies and regulations (Groat and Grimshaw, 2012). Their report focused on three of the major shale gas plays: Barnett, Haynesville, and Marcellus. Based on their review of the published literature, they found a broad consensus and drew five conclusions related to hydraulic fracturing and induced seismicity (Groat and Grimshaw, 2012):

1. The amount of fluid pumped during the hydraulic fracturing process is of orders of magnitude less than that required to propagate fractures upward to freshwater aquifers.
2. Tensile fractures created by hydraulic fracturing will have a very short life of enhanced permeability if they are not propped open by injected proppant particles.
3. Gas production will lower pressure in the fractured reservoir and drive fluid flow in and down, even after production has ceased.
4. Many of the fracturing fluid chemicals will rapidly dissipate during fracturing by reaction with the fractured rock surface, and some chemicals will be adsorbed on organic components and clay minerals.

5. After fracturing, any residual, depleted, fracturing fluid would mix with formation brines (as is seen in changes over time in the flowback water) and upward migration will essentially be impossible without very high driving pressures that do not exist.

The NRC examined the scale, scope, and consequences of seismicity induced during fluid injection and withdrawal related to energy technologies, including shale gas recovery, and concluded that, "the process of hydraulic fracturing a well as presently implemented for shale gas recovery does not pose a high risk for inducing felt seismic events" (NRC, 2012). The NRC (2012) noted that the very low number of felt events compared to the large number of hydraulically fractured shale gas wells is likely due to the short durations for injecting fluids, the limited volumes of fluid used, and the small spatial area affected by hydraulic fracturing.

5.3 Underground Injection of Liquid Wastes

In contrast to hydraulic fracturing for shale gas production, wastewater from oil and gas production, including shale gas production, is typically disposed by injecting it at relatively low pressures into extensive formations that are specifically targeted for their porosities and permeabilities to accept large volumes of fluid. Many of the well-documented instances of induced seismicity associated with fluid injection involve large amounts of fluids injected over long periods (NRC, 2012).

Underground injection of fluids is a common practice in the United States. The USGS (Nicholson and Wesson, 1990) lists a variety of examples of deep well injection operations, including wastewaters, solution mining, geothermal energy extraction, enhanced hydrocarbon recovery, and the underground storage of natural gas. EPA (2013) UIC regulates the construction, operation, permitting, and closure of injection wells that place fluids underground for storage or disposal. EPA and 39 states regulate more than 150,000 Class II injection wells for disposal of oil and gas wastewaters. The increase in hydraulic fracturing for shale gas production increased public awareness of induced seismicity from underground injection of fluids, so EPA (2013) added injection-induced seismicity as a research focus of its National Technical Workgroup.

Horton (2012) describes an increase in seismic activity in northcentral Arkansas following the installation of eight wells for the disposal of hydraulic fracturing wastewater from the Fayetteville Shale. While the area is prone to natural earthquake activity, the rate of 2.5 magnitude and greater earthquakes increased after the first disposal well started operations in April 2009. While there was one earthquake in 2007 and two in 2008, the number jumped to 10 in 2009, 54 in 2010, and 157 in 2011. Some 98 percent of the recent earthquakes happened within 6 km of one of three of the eight disposal wells. Horton concludes that this "close spatial and temporal correlation supports the hypothesis that the recent increase in earthquake activity is caused by fluid injection at the waste disposal wells" (Horton, 2012).

Frolich (2012) analyzed data from 67 earthquakes with 1.5 magnitude and greater in the Barnett Shale region that occurred between November 2009 and September 2011. He found that the 24 events with the most reliably identified epicenters were in eight groups within 3.2 km of one or more injection wells. All wells nearest the earthquake groups had injection rates greater than 150,000 bbl/month; however, not all wells with these injection rates were accompanied by earthquakes. Frolich (2012) hypothesizes that injection triggers earthquakes only if injected fluids relieve friction on a suitably oriented fault that is already under regional tectonic stress.

Between March 2011 and March 2012, the Ohio Department of Natural Resources (ODNR) recorded 12 low-magnitude seismic events ranging in magnitude from 2.1 to 4.0. Between the establishment of the ODNR "OhioSeis" seismic network in 1999 and 2011, no earthquake activity was recorded in the Youngstown area. The ODNR (2012) did note three earthquakes recorded in the area between 1986 and 2000 with magnitudes of 3.0–5.2, but the 2011–2012 events all occurred within a mile of the Northstar 1 deep injection well, which began operations in December 2010.

Approximately 35 separate inspections of the well in 2011 all concluded that the well was operating within its permitted injection pressure and volume; tests showed that the injections were within the permitted depth intervals, albeit with inconclusive results regarding the fluid volume reaching the bottom of the well at 9,184 feet. In late 2011, additional seismic monitoring equipment deployed in the area measured a 2.7 magnitude earthquake at 2,454 feet below the injection well. The ODNR (2012) determined that a "number of coincidental circumstances appear to make a compelling argument for the recent Youngstown-area seismic events to have been induced." These circumstances 87include the spatial proximity of the seismicity to the well and the temporal proximity to the start of injection, as well as evidence of higher-permeability zones in geophysical well logs.

The ODNR (2012) outlined circumstances that must be met for an injection well to induce seismicity:

- A fault must exist in the underlying basement rock
- The fault must be in a near-failure state of stress
- An injection well must be drilled deep and near enough to the fault to communicate hydraulically with the fault
- The operator must inject enough fluid at high enough pressures for an adequate amount of time to cause movement (failure) along the fault

The well was shut down on December 30, 2011. On December 31, a 4.0 magnitude earthquake in the Youngstown area led the State of Ohio to declare a moratorium on deep injection wells. Since the Youngstown event, Ohio has initiated a set of reforms to its Class II deep injection well program that include additional geologic and geophysical data, well testing, monitoring, and operational controls.

Keranen et al., (2013) interpreted three earthquakes that occurred near Prague, Oklahoma, east of Oklahoma City, in November 2011 with magnitudes of 5.0–5.7 as induced by increased fluid pressures from underground injection. The initial rupture was within 200 meters of active injection wells and within 1 km of the surface; they interpreted the lowered effective stress on nearby faults as the result of 18 years of injection. They described an increase in significant earthquakes in the U.S. continental interior concurrent with an increase in the volumes of fluids related to unconventional resource production being injected into the subsurface. The authors concluded that this indicates that decades can pass between the start of injection and incidents of induced earthquakes.

Following publication of the abstract for Keranen et al*.* (2013) and subsequent news articles, David Hayes (2012), Deputy Secretary of DOI, clarified some points about the USGS's work. Among the preliminary findings described, he stated:

> USGS's studies do not suggest that hydraulic fracturing, commonly known as "fracking," causes the increased rate of earthquakes. USGS's scientists have found, however, that at some locations the increase in seismicity coincides with the injection of wastewater in deep disposal wells.

Hayes (2012) went on to explain that injection of wastewater is known to have the potential to cause earthquakes. However, of the 150,000 Class II wells in the United States, including approximately 40,000 for oil and gas operations, only a tiny fraction have induced earthquakes large enough for public concern. He noted that there are no methods available to anticipate whether an injection will trigger earthquakes large enough to cause concern. The USGS is working with DOE and EPA to better understand induced seismicity.

In March 2013, the OGS (Keller and Holland, 2013) concluded that the Prague event resulted from natural causes, and that further study will improve monitoring and understanding of seismicity in Oklahoma. These authors analyzed earthquake and 3-D reflection seismology, formation data, and historical data, observing that the Prague event was consistent with what is known about natural earthquakes in Oklahoma.

The NRC (2012) found that underground injection of wastewater poses some risk for induced seismicity, but that very few events have been documented over the last several decades compared to the large number of operating disposal wells. The NRC also noted that "the long-term effects of a significant increase in the number of wastewater disposal wells for induced seismicity are unknown" (NRC, 2012).

The NRC (2012) presented their findings, identified gaps in knowledge or information, proposed actions, and recommended further research to address induced seismicity potential in energy technologies. Referring to all energy technologies, they proposed that a local seismic monitoring array be installed in locations where a relationship may exist between extraction/injection and seismic activity. When seismic events appear to be associated with hydraulic fracturing and are cause for concern for public health and safety, an assessment should be performed to understand the causes of the seismicity. Regarding disposal injection wells, the NRC recommended adoption of a best-practices protocol, and where operations could induce unacceptable levels of seismicity; full disclosure and public discussion are needed before operations begin. The NRC outlined practices to consider induced seismicity and develop technology-specific best practices protocols to reduce the possibility of and to mitigate the effects seismicity. They refer to a recent protocol for geothermal systems developed by DOE for geothermal systems (Majer et al., 2012).

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6 LAND USE AND DEVELOPMENT

Land use and development issues associated with natural gas production include property rights disputes and use of public lands; local surface disturbance; cumulative landscape impacts; habitat fragmentation; and traffic, noise, and light. Concerns have been expressed with competing uses for public lands, the cumulative impacts of multiple industries (e.g., timber and tourism), and denial of access to areas with active operations (CMSC, 2011). Surface disturbance involves not only site preparation and well pad construction, but also road, pipeline, and other infrastructure development. The cumulative impacts of surface disturbance can extend over large areas and can also result in habitat fragmentation that impacts both plant and animal species. Mitigation options include adoption of best-practices for site development and restoration, avoidance of sensitive areas, and minimization of disturbed areas. As development and production operations proceed, local residents can be confronted with increased truck traffic, sometimes more than 1,000 truck trips per well, and additional noise and light as construction, development, drilling, and production typically proceed 24 hours per day. Vertical wells are typically spaced with 40 acres per well, the drill pads from which each horizontal well originates are typically spaced with 160 acres per well. A single square mile of surface area would require 16 pads for 16 conventional wells, while the same area using horizontal wells would require a single pad for 6–8 wells (NETL, 2009).

6.1 PROPERTY RIGHTS AND PUBLIC LANDS

The Citizens Marcellus Shale Coalition (CMSC) (2011) explored two issues related to impacts of shale gas production on public lands and the other industries that rely on these lands. They also explored the impacts on private property rights. CMSC stated that shale gas development must consider the cumulative impacts on state parks and forests and on timber and tourism industries as part of responsible stewardship of public resources. Property rights and environmental degradation are a growing public concern, and eminent domain laws, drill spacing requirements, and grouping of leased lands could help protect these rights.

Stolz (2011) noted that local disturbances result from the large amounts of land that are needed for well pads and impoundments, and from the fact that the pad remains active as long as a well can be re-stimulated. Regionally, Stolz expressed concern that access to leased areas (on both private and public lands) becomes restricted, and public lands and parks, in particular, are no longer “public,” because safety renders them off-limits.

A presentation by William Lanning of the BLM (2013b) explained that any oil and gas development on lands owned by the federal government is managed by agencies including the BLM or USFS. For resources that are either privately owned or owned by the state, development and regulation is many times managed at the state level, but federal agencies still control the oversight of the development at a high level (BLM, 2013b).

6.2 SURFACE DISTURBANCE

The Sierra Club expressed concern with regional transformation and landscape change from increasing shale gas production (Segall and Goo, 2012). Regionally, hundreds of thousands of new wells and their accompanying infrastructure can require significant construction activity in rural areas with thousands of trucks moving on a growing network of roads (Segall and Goo, 2012). Locally, each well pad covers about three acres with an equivalent amount for infrastructure, and much of this area remains disturbed through the life of the well, as long as 20–40 years.

The development process begins with preparation and construction of access roads and the well pad site. The operators clear vegetation and level the ground's surface, creating additional space for the trucks and drilling rig. As drilling proceeds, the operators bring in equipment to mix the water, additives, and sand needed for hydraulic fracturing—tanks and pumps, as well as water and sand storage tanks, additive storage containers, and monitoring equipment. Based on the geological characteristics of the formation and climatic conditions, operators may excavate pits or impoundments, or use tanks, to store freshwater, drilling fluids, or drill cuttings. Operators may also install pipes temporarily to move materials on- and off-site. As is the case with other construction activities, erosion controls may be needed to contain or divert sediment away from surface water or else precipitation and runoff can carry sediment and other pollutants into nearby surface waters (GAO, 2012).

A BLM (2013a) presentation stated that the use of land for oil and gas development should have as small a footprint as possible, and the development should be viewed as a temporary use of the region. The three phases of land use include planning before development, minimizing impacts during development, and restoration of the land following completion.

Drohan and Brittingham (2012) investigated topographic and soil characteristics that could affect infrastructure development and reclamation success of shale gas pads in Pennsylvania. They determined that the development related to a single shale gas pad ranges 0.1–20.5 hectares (ha) with a mean size of 2.7. More than half of the pads in Pennsylvania are built on slopes with risks of excess surface water movement and erosion. About three-quarters of the pads are built on soils without drainage problems, while almost a quarter are built on potentially wet soils. Aerial photographs show that some pads have been restored and planted with grass. Some crop production could be observed on restored agricultural lands. Poor soil reclamation may limit re-vegetation of grasslands and forests.

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Commented [HSAJ104R102]: If you are only going to cite once at the beginning of a paragraph, then it needs to be crystal clear to the reader that these findings are related to the work of Drohan and Brittingham 2012. Suggest the sentences following the citation read as "They find..." or something similar.

The low natural permeability of shale reservoirs requires closer well spacing intervals than conventional gas reservoirs to optimize production. However, the horizontal drilling technology now used in shale gas plays allows for more wells to radiate outward from a single pad. For example, 6–8 horizontal wells can be drilled from a single pad and equal the production of 16 vertical wells developed on 16 pads to cover an area of 1 mile by 1 mile (259 ha). This also reduces the miles of roads and pipelines, and the amount of infrastructure needed (DOE, 2009). An assessment of impacts from oil and gas development in EPA's Region 8 (Colorado, Montana, North Dakota, South Dakota, Utah, and Wyoming) agreed that using horizontal drilling allows several wells to be drilled from a single pad, which would lower the amount of land required (EPA, 2008).

Considine et al. (2012) analyzed notices of violations (NOVs) issued by the Pennsylvania Department of Environmental Protection from January 2008 through August 2011 that were related to Marcellus shale gas drilling. While 62 percent of the NOVs were administrative or preventative, the remaining 38 percent represented 845 polluting environmental events that produced 1,144 environmental violations. The Considine et al. study categorized these environmental violations into major and non-major events and identified 25 major events. Major events included "major site restoration failures, serious contamination of local water supplies, major land spills, blowouts and venting, and gas migration" (Considine et al., 2012). Violations related to site restoration made up two of the 25 major violations (land spills and water contamination composed 17 of the 25, or 68 percent) and 39 percent of minor violations, composing the most frequent category of minor violation.

Site restoration events result when the operator does not restore a drilling site in accordance with Pennsylvania Department of Environmental Protection guidelines, including removal of drilling equipment and waste and restoration of 70 percent of the perennial cover within nine months. Erosion was a problem cited in most NOVs; in some cases, equipment was not removed, or vegetation was not restored. Land disturbances have an environmental impact, but they can be remediated with minor reclamation efforts and are not as serious as spills and water contamination (Considine et al., 2012).

6.3 Cumulative Landscape Impacts

Slonecker et al. (2010) quantified the landscape changes and consequences of Marcellus Shale and CBM natural gas extraction in Pennsylvania. Because the combined effects of these two methods create potentially serious patterns of landscape disturbance, disturbance patterns were digitized and used to measure changes. By 2010, 300,000 ha, or 0.41 percent of the land area, in Bradford County and 223,000 ha, or 0.85 percent of the land area, in Washington County had been disturbed by shale and CBM natural gas production. Their results illustrate the effects of natural gas extraction in Pennsylvania on the landscape, primarily in disturbance to agricultural and forested areas.

Commented [HSAJ105]: Define ha if not done so previously.

Drohan et al. (2012) examined land cover change due to shale gas exploration in Pennsylvania, with an emphasis on forest fragmentation. This development has taken place mostly on private property and on agricultural and forest lands. Most drill pads have one or two wells; fewer than 10 percent of pads have five or more wells. As of June 2011, the development of all permits granted would convert 644–1,072 ha of agricultural land and 536–894 ha of forest, plus at least 649 km of new roads and additional pipelines. Drohan et al. (2012) recommended a regional strategy to help guide infrastructure development and manage habitat loss, farmland conversion, and risks to waterways.

A report compiled for the U.S. Department of Agriculture examined the impacts of natural gas development at a site in the Monongahela National Forest (Adams et al., 2011). Adams et al. estimated that a total land area of 1.4 ha would be cleared, including the well pad site and access road. Major impacts that were investigated include the erosion of soil and sediment, water quality, and vegetation condition. The actual land area cleared for the well pad and access road ended up being 0.83 ha, 0.57 ha less than what was originally estimated.

Silt fences were installed around the well pad and near the road to minimize the loss of sediment; however, these measures were not very effective due to several factors. The amount of sediment trapped by some of the fences allowed a conservative estimate of 2.1 metric tons/ha of soil material eroded. The authors reported an unexpected severe impact on vegetation, which was attributed to both the accidental and purposeful release of drilling fluids to the air. In some regions, there was no reported effect the following year, but in others the impacts continued the following year. There were other reported impacts that were unexpected, including heavier than predicted use, procedural and technical changes, and vehicular accidents (Adams et al., 2011).

Stormwater runoff from drilling sites and related infrastructure can impact water quality and ecosystems along local waterways. A site without runoff controls can allow as much as 16 times the runoff of an equivalent vegetated area and natural gas drilling requires about 7–8 acres per well pad. Stormwater flowing across drill sites may contain pollutants from the stored fracturing fluid and produced water on-site. On the other hand, horizontal drilling reduces the number of well pads needed to reach the target formation, so the amount of surface disturbance is less than that needed for purely vertical drilling (The Horinko Group, 2012).

6.4 Habitat Fragmentation

The construction and installation of the infrastructure necessary for development of the natural gas can lead to a habitat being converted from a large contiguous patch of similar environments to several smaller, isolated environments. Long-term effects of shale gas production on habitat disturbance will have to be evaluated as the development of these resources proceed. Mitigation measures such as avoidance, best management practices, and prompt reclamation of the drilling site have been put forward as ways to best minimize the possible impacts that shale gas production may have on habitats. Habitat disruption can also result from a lack of surface water availability in response to withdrawals and quality from erosion and chemical spills. Water use and quality are discussed further in Chapter 4 – Water Use and Quality.

6.4.1 Description of Habitat Fragmentation Impacts

There are several impacts associated with the development of gas drilling sites and gas production that can disrupt the habitat of both plant and animal species. These impacts can arise from a variety of sources and at various points throughout the extraction and production process. Habitat fragmentation occurs when infrastructure must be installed, or land clearing must take place to allow access to a well location. Habitat fragmentation was given as one of the environmental risk pathways that were identified as a consensus priority risk pathway in a survey of 215 experts in government, industry, academia, and non-governmental organizations (RFF, 2013).

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Before fragmentation takes place, a given habitat is considered a single, contiguous region consisting of a type of landscape or environment. Anthropogenic activities and infrastructure can intersect and divide a landscape into a series of smaller, unconnected patches that become more isolated than they were previously (USGS, 2012). Forested areas are particularly vulnerable when land is cleared and leveled for the installation of infrastructure such as roadways and pipelines, leading to a decrease in the forest cover available for plant and wildlife species, and ecosystems (USGS, 2012; GAO, 2012).

Processes having to do with shale gas production can have impacts on habitat and landscapes during all aspects of the operation, including exploration, development, operations, and closure (NETL, 2009). Land, especially land with vegetative growth already present, must be cleared and then graded or leveled so that infrastructure may be installed. Gaining access to the drilling sites means that new roads must be constructed. This results in land disturbance and fragmentation through a habitat. Pathways for pipelines to transport extracted natural gas must also be constructed, leading to similar disruptions as that of road installation. Other necessary pieces of shale gas production infrastructure, including storage tanks and well pads, also lead to habitat fragmentation (GAO, 2012).

The New York State Department of Environmental Conservation (NYSDEC) (2011) released a draft Supplemental Generic Environmental Impact Statement in 2011 to examine potential environmental impacts that could result from shale gas drilling operations in the Marcellus Shale of New York. The study determined that permitting shale gas drilling operations utilizing high-volume hydraulic fracturing techniques would lead to “significant” environmental impacts, including habitat fragmentation and declines in wildlife population and overall biodiversity. There would be both short- and long-term impacts due to the activities associated with the shale gas drilling process, mainly those discussed in the previous paragraphs (NYSDEC, 2011).

A USGS (2012) report examined the effect of natural gas extraction during 2004–2010 on landscapes in two Pennsylvania counties: Bradford County in northeastern Pennsylvania and Washington County in southwestern Pennsylvania, both of which are located in the interior of the Marcellus Shale region. The authors used several landscape quantification metrics to analyze the landscape changes over the period. Forest regions are especially affected by habitat fragmentation, as large contiguous tracts of forest are broken up into smaller, more isolated patches of forest as a result of drilling infrastructure. Exhibit 6-1 provides a depiction of the effect that drilling infrastructure such as roads, well pads, and pipelines can have on forested land (USGS, 2012). The graphic shows forest area in McKean County, Pennsylvania, where natural gas development has taken place and fragmented the habitat into smaller patches. There were four results that pertained to forest fragmentation from this study (USGS, 2012):

- There were a greater number of individual forest patches, each averaging less area in 2010 than in 2001.
- There were over 300 more individual sections of forest in Bradford County in 2010, with an average area almost 3 ha less in 2010.
- There were over 1,000 more individual sections of forest in Washington County in 2010, with an average area almost 7.5 ha less in 2010.
- Much of the increase in the number of individual forest patches was due to the construction of pipelines for product transport.

Exhibit 6-2 shows cumulative impacts for a non-forested area in Wyoming, which shows some of the increased erosion and soil runoff due to the lack of stabilizing vegetation (USGS, 2013). Areas like this may require different remediation and site restoration approaches.

Exhibit 6-1. The effect of landscape disturbances on forest habitat

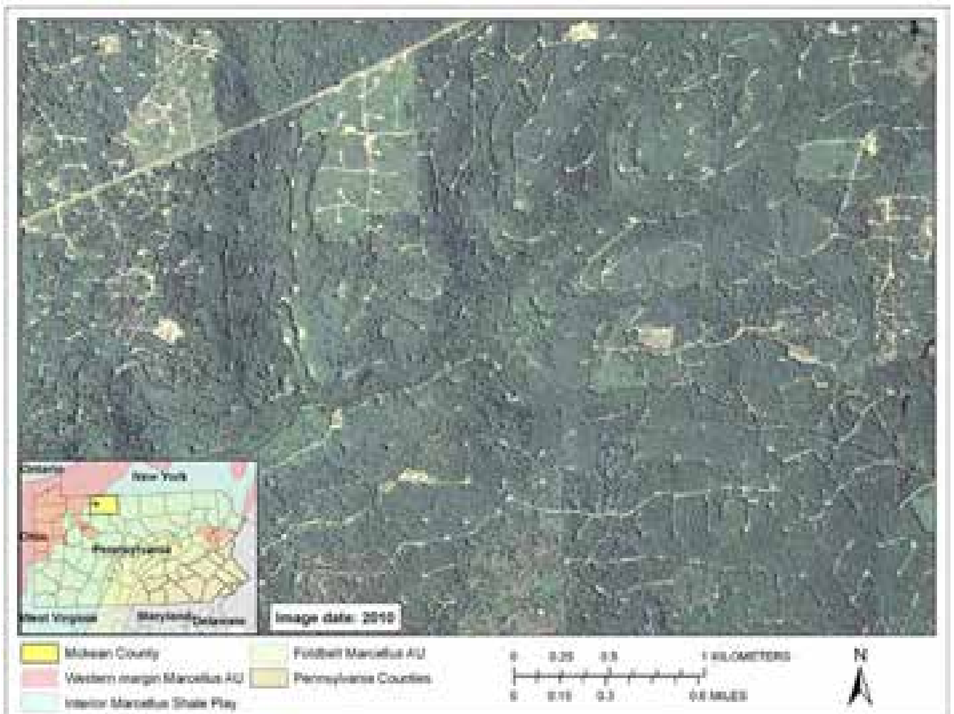

Exhibit 6-2. The effect of landscape disturbance on non-forest habitat (Wyoming, USA)

The Wilderness Society (2008) performed an analysis of the impacts that oil and gas development can have on wildlife due to habitat fragmentation using metrics for road density and distance to the nearest road. The scenario simulation they performed involved randomly locating well pads on a map grid, creating road segments to service the well pads from existing roadways, and converting the data for comparison with current development (The Wilderness Society, 2008). The report found that habitat fragmentation and impacts on wildlife happen even at low well pad density and (though this analysis and available literature can help inform BLM decisions) site-specific evaluations are the best way to determine the extent of habitate fragmentation and impact of development (The Wilderness Society, 2008).

The Wilderness Society (2008) made seven recommendations to allow impact analysis under the National Environmental Policy Act:

- Analyze the impacts of all the available development alternatives
- Evaluate the development impacts at maximum well pad density
- Include possibilities that do not develop important wildlife habitats
- Ensure that analyses are done at the scale of the landscape
- Make use of geographic information systems in analyses
- Recognize more involvement from the public and other stakeholders when landscape analysis is utilized
- Monitor wildlife indicators to measure the effect of any habitat fragmentation

A study by The Nature Conservancy (2010) analyzed Marcellus Shale development in Pennsylvania and projected the impact it would have on natural habitats. Each current Marcellus well pad and accompanying infrastructure results in approximately 8.8 acres of cleared forest and 21.2 additional acres of forest edge habitat. They estimate that by 2030, 60,000 new wells will be drilled, resulting in 6,000 new well pads, if there are 10 wells per pad; 10,000 new well pads, if six wells are drilled per pad; and 15,000 new well pads, if four wells are drilled per pad (The Nature Conservancy, 2010). This amount of development would require between 10,000–25,000 miles of additional installed pipeline. The amount of new forest edge habitat as a result of increased development, a range of 400,000–1,000,000 acres, could result in increased predation, changes in the local environment, and increased nonnative species (The Nature Conservancy, 2010).

According to a GAO (2012) report, it is difficult to quantify the long-term effects of shale gas production on habitat fragmentation, because there has not been sufficient time to evaluate these effects. The data do not yet exist to enable a reliable evaluation of what may be the long-term effects of shale gas development. A joint study by the Houston Advanced Research Center and the Nature Conservancy evaluated how surface disruptions, such as the installation of a well pad and drilling rig and the noise levels from equipment running at the drill site, would affect a species of prairie chicken (GAO, 2012). It was determined that the noise did not seem to negatively affect the chickens; however, the drilling rig being there in general led to the chickens temporarily vacating the vicinity (GAO, 2012). The longer the operations are in place, the easier it will be to quantify the long-term effects of shale gas production.

The examination of a natural gas development site in the Monongahela National Forest provided evidence that the installation of a pipeline to transport extracted gas created 3,000 meters of forest edge habitat from approximately 2 ha of cleared right-of-way. These forest edges can provide easy access for predators to nests as well as openings for invasive species (Adams et al., 2011). An assessment performed by EPA (2008) stated that there are concerns over migratory disruption, habitat disruption, and locations where some animals spend the winter that stem from oil and gas development.

Many development operations have been in practice for far longer than shale gas drilling, such as conventional natural gas production and other unconventional gas production (tight gas and CBM). The impacts of habitat fragmentation due to these similar processes are far better known and, therefore, habitat fragmentation impacts and mitigation measures can be understood fairly well. Habitat fragmentation impacts vary greatly depending on the landscape, the extent of exploration, production, and development, and any existing infrastructure or corridors in the vicinity prior to the development of gas resources.

6.4.2 Mitigation Options for Habitat Fragmentation Impacts

The NYSDEC (2011) study proposed that, if the development area included a region of continuous forest over 150 acres in size or a region of grassland over 30 acres, an ecological assessment should beconducted to identify best management practices.

A 2012 study of hydraulic fracturing practices in the Inglewood oil field in California, operated by the Plains Exploration & Production Company proposed that the best way to mitigate habitat fragmentation impacts is to adopt best management practices, perform wildlife surveys, and implement restrictions during migration and mating seasons (Cardno ENTRIX, 2012). The study also found that ensuring that well pad reclamation occurs is the most productive method to reduce harm to populations (Cardno ENTRIX, 2012).

Avoiding disturbances to sensitive areas such as wetlands, waterways, and wildlife habitats when locating drilling sites could be the best method for mitigating impacts. Reclaiming the land upon completion of drilling activities is the best way to mitigate impacts in those cases when avoiding disturbances is impossible (NETL, 2009). Proceeding with reclamation processes as quickly as possible can minimize the disturbances, but all mitigation measures (including avoiding disturbances to begin with) are subject to the landscape, plants, and wildlife that are present at a site.

The Western Governors' Association (2006) released a handbook outlining the best management practices for CBM development to be shared among the Association's shareholders. The practices are split into multiple categories, including planning, water, landowner relations, and infrastructure. Several subcategories can be applied to mitigating habitat fragmentation, such as protection of wetland areas, roads and transportation, pipelines and power lines, habitat and species protection, and wells. To protect wetland and riparian areas, facilities such as well pads should be sited outside of such regions as much as possible, and features that cut across the landscape, such as roads and pipelines, should avoid crossing wetlands and riparian areas as much as possible (Western Governors' Association, 2006). Best practices for mitigating disturbance from roads and transportation include keeping road development to a minimum, using existing access roads as much as possible, using unimproved roads as little as possible during wet weather, following road construction and maintenance standards, avoiding sensitive areas, and attending to safety issues and other problems (Western Governors' Association, 2006). Recommendations of best practices for pipelines and other lines include using existing pathways, installing as many lines as possible in a single location, and using the least invasive construction equipment possible. To protect habitat and sensitive species, lines should be buried rather than installed above ground if possible. Well sites should minimize the amount of surface disturbance that occurs and should be reclaimed as quickly as possible upon completion of development activities (Western Governors' Association, 2006). Again, these best management practices have been developed in areas of CBM production by the Western Governors' Association, but many of these practices are applicable to shale gas development.

Drilling on federal or public lands is subject to oversight by federal agencies, and sections of the Endangered Species Act may require that species of plants or animals not be threatened by the permitted drill site (NETL, 2009). Mandatory plans for mitigation and reclamation may be required to ensure that impacts on wildlife and habitat will be as minimal as possible (NETL, 2009).

With approximately 33 units of the National Park System in or near the Marcellus Shale, NPS found it important to be informed and current with development issues. Moss (2012) provides an overview of the geology, technology, current activity, and potential environmental impacts. Among the effects described are widespread development and well spacing, site space needs, water use, aquifer contamination, air quality, and truck transportation. There are then four recommendations to help park units prepare for potential shale gas development on and around NPS lands (Moss, 2012):

1. Check land and mineral ownership – Know if private in-holdings or private or state mineral estate underlie an NPS unit.
2. Be aware of industry interest adjacent to park boundaries – Land speculation, exploration, or drilling could signal increased requests for drilling permits. Contact the state oil and gas agency to express concerns and issues.
3. Work with state agencies – Meet with the state permitting agency, establish agreements, engage before issuance of permits, and if possible, have protective mitigation measures included directly in the lease.

The NPS Geologic Resources Division assists parks with policy and technical issues and reviews permitting and environmental documents to help mitigate or eliminate adverse impacts (Moss, 2012).

In January 2013, the BLM updated a presentation detailing best management practices for wildlife management that can help to minimize habitat fragmentation. The document offers several practices that can be implemented or planned to lessen impacts on habitat. The well pad itself and the immediate surroundings can be fit to the space available to minimize the disturbed area, rather than constructing a generic rectangular pad (BLM, 2013a). There are also multiple examples of reclamation practices, both at the drill site and on access roads, that can be implemented to lessen the impact of the infrastructure. The well pad and supporting infrastructure (roads, pads, storage, and pipes) can be designed to be as efficient and minimally obstructive as possible (BLM, 2013a). Wells can be remotely monitored using telemetry, pipelines and other lines can be buried where possible, and any existing corridors for roads and lines should be used whenever possible (BLM, 2013a). It is helpful to monitor local wildlife populations to ensure that mitigation and reclamation measures are effective, and final reclamation upon abandonment of the well is critical to the long-term effectiveness of mitigation options (BLM, 2013a).

6.5 Traffic, Noise, and Light

In the *Revised Draft Supplemental Generic Environmental Impact Statement on The Oil, Gas and Solution Mining Regulatory Program*, NYSDEC (2011) identified temporary but adverse noise and visual impacts from construction activity and increased truck traffic among the potential land-use environmental impacts associated with natural gas production. Significant adverse impacts in terms of damage to local and state roads could also result. Among mitigation measures described for environmental impacts, NYSDEC suggests imposing measures to reduce the adverse noise and visual impacts from well construction. A transportation plan could also be required that would include proposed truck routes and assess road conditions along the proposed routes. Exhibit 6-3 tabulates the number of truck trips for a typical shale gas well (MIT, 2011).

Exhibit 6-3. Truck trips for a typical shale gas well drilling and completion

Activity	1 Rig, 1 Well	2 Rigs, 8 Wells
Pad and Road Construction	10–45	10–45
Drilling Rig	300	60
Drilling Fluid and Materials	25–50	200–400
Drilling Equipment (casing, drill pipe, etc.)	25–50	200–400
Completion Rig	15	30
Completion Fluid and Materials	10–20	80–160
Completion Equipment (pipe, wellhead, etc.)	5	10
Fracturing Equipment (pump trucks, tanks, etc.)	150–200	300–400
Fracture Water	400–600	3,200–4,800
Fracture Sand	20–25	160–200
Flowback Water Disposal	200–300	1,600–2,400
TOTAL	1,160–1,610	5,850–8,905

The large volumes of water involved in fracturing operations can create high volumes of road traffic given the majority of the water used for fracturing is transported by truck. It should be emphasized that the large number of traffic movements shown in the table above are worst-case estimates. In particular, re-use of flowback wastewater significantly reduces the amount of road traffic associated with hauling water, which represents much of the traffic movement. Furthermore, large-scale operators are also using pipelines to transport water to the site, substantially reducing the amount of road traffic (MIT, 2011). An assessment performed by EPA (2008) in their Region 8 stated that the trucks and roads that are used during oil and gas development processes affect the surrounding environment through localized noise pollution.

The Eagle Ford Shale Task Force Report for the Railroad Commission of Texas identified increased traffic and deterioration of roads and bridges among the infrastructure impacts from shale gas development (Porter, 2013). Exhibit 6-4 lists estimates of the number of truck-trips-per-shale-gas-well in the Eagle Ford (Porter, 2013).

Exhibit 6-4. Loaded truck trips per gas well

Activity	Number of Loaded Trucks
Bring well into production	1,184
Maintain production (per year)	Up to 353
Re-fracturing (every 5 years)	997

These impacts are enough of a concern that the task force considered alternative financing methods to help meet the increased demands on roads and bridges (Porter, 2013).

Upadhyay and Bu (2010) surveyed the visual impacts of Marcellus drilling and production sites in Pennsylvania. They reviewed the drilling process, assessed direct visual impacts, and compared the results to the impacts of other technologies (e.g., windmills and cell towers). They also studied drill-pad density from map and aerial perspectives to examine the likelihood of seeing drill towers across a landscape, and the modeled potential impacts for increased drilling, making the following conclusions:

- Serious impacts from light and noise are a potential problem within a small radius of drilling sites
- Indirect impacts like increased truck traffic, equipment storage, and temporary structures compose the most salient visual impacts, rather than the drill pads themselves
- Timelines for site restoration of visual impacts vary significantly

Upadhyay and Bu (2010) recommended that visual impacts be addressed during the siting and design phase and that nighttime impacts could be avoided by pointing lights downward.

The RFF (2013) report also gave several options in their survey of experts under the category of community disruption. Included in this category, as well as habitat fragmentation, were such risks as light pollution, noise pollution, odor, and road congestion. The industry respondents identified a number of these community disruptions as risk pathways of high priorities, while the other respondent groups identified more conventional (air pollution, water pollution, etc.) risks.

SEAB recognized that shale gas production brings both benefits and costs to communities, often rapidly, including places that are unfamiliar with natural gas operations. Impacts include traffic, noise, and land use, with little or no allowance for planning or effective mechanisms to engage stakeholders. SEAB does not believe that these kinds of issues will solve themselves or that regulation or legal action will solve them. State and local governments should lead experiments with alternative mechanisms for addressing these issues constructively and seeking practical mitigation. The federal government may also help through mechanisms like the U.S. Department of Interior's Master Leasing and Development Plans, which might help improve planning for production on federal lands (SEAB, 2011).

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7 Social Justice and Natural Gas/Liquefied Natural Gas Market Development

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7.1 Introduction

Historically, investments into energy projects have been planned, designed, and implemented within societal frameworks explicitly or implicitly built around exclusion (Ciplet & Harrison, 2019). Because of the large upfront capital costs for building energy infrastructure, the power plants, transmission networks, and oil pipelines we rely on today have been in place for decades and in some cases, nearly a century. In a sense, the continued existence of those legacy assets perpetuates the historical frameworks of exclusion under which they were developed. The distribution of benefits and disbenefits have often created "winners" and "losers" in a manner that perpetuates which communities will be disadvantaged – almost by design. Mitigating for climate change provides the proverbial "once in a lifetime" opportunity to re-frame the foundations upon which our critical infrastructure is built in a manner that brings historically disadvantaged communities to the planning table to ensure that the nation's best laid plans are best for all, not just some.

These considerations have driven the implementation of the administration's Justice 40 initiative, which has an explicit goal that 40% of the benefits from federally-funded projects should be accrued within communities of historically disadvantaged, disenfranchised, and burdened by pollution. Specific types of projects include those related to the energy transition both in energy production, as well as in the effort to electrify transportation. Additional categories include affordable housing, workforce development and training, as well as those focused on the remediation of legacy pollution, clean water initiatives, and wastewater projects. Introducing the Justice 40 framework into the ways in which government measures the distribution of project benefits attempts to right the historical wrongs that have resulted in the inequitable outcomes we see today by requiring the success of project outcomes to be measured according to whom the benefits and disbenefits are distributed (Justice40, 2023).

This chapter seeks to summarize the incorporation of social justice concepts.

in the broader research literature on natural gas and liquefied natural gas market (LNG) development. The goal is to summarize what already exists and provide guidance as to how future research might be pursued at the nexus of social justice and project development. Our specific focus is on the development of large-scale energy infrastructure intended to serve the energy transition goals outlined by the current administration and its policies. However, the challenge (and opportunity) researchers face in this space is rooted in the relatively light focus that has been paid on applying energy justice concepts to the development of infrastructure projects specifically for natural gas and LNG markets.

Due to the nascency of research that links social justice issues with the development of natural gas and LNG markets, this literature review will read somewhat proscriptively. Our goal is to cover research that has already connected these issues and weave together the separate literature areas into the discussion. For a guiding light, we consider the framework presented in

Spurlock et al. (2022) that outlines a tractable framework to incorporate energy justice tenets into energy infrastructure planning and deep decarbonization policy implementation strategies.

We further frame this discussion as a struggle to balance Energy Justice issues rooted in the inequitable accrual of pollution and dis-benefits with the need to ameliorate for Energy Poverty where communities do not have equitable access to cheap, reliable energy. We conclude by underscoring the idea that the considerations of energy justice tenets (Distributional, Recognition, and Procedural) must be done from the holistic inflection point of energy project governance as it is the fulcrum of all project planning, development, and implementation occurs. It is from the point of governance that the effort to ameliorate energy poverty through the implementation of energy justice efforts that can produce a just transition away from our carbon-intensive economy and towards a more sustainable outcome.

The rest of the chapter is organized into sections covering the three primary tenets of Energy Justice before we delve into the topic of Energy Justice itself. We then broach the topics of Energy Poverty, Just Transitions, Protests and end with a short entry on Energy Governance and Sustainable Development.

7.2 DISTRIBUTIVE, PROCEDURAL, AND RECOGNITION JUSTICE

The broad scope of energy justice breaks down into the three core tenets of distributive, procedural, and recognition justice (Spurlock et al., 2022). To aid in the understanding of energy justice writ large, we present this short background section on these three tenets.

7.2.1 Distributional Justice

Distributional Justice is focused primarily on the equitable distribution of benefits and dis-benefits across communities (Spurlock et al., 2022). It is a concept focused on the well-being of individuals, which span the gambit of human outcomes such as psychological well-being, societal well-being and physiological well-being (Deutsch, 1975). Distributional justice delves into the nuanced context in which equity versus equality versus need may dominate in identifying unjust distributions.

Fairness is a key concept within distributional justice and can be characterized as a problem for geospatial analysis (Bouzarovski & Simcock, 2017). Across the energy supply chain, distributional justice is a problem of implied risk responsibility as well as costs and benefits (Heffron & McCauley, 2014). Where a historical lack of inclusiveness has created inequities also lies the risk that those structural deficits will compound under a changing climate. In other words, the deficits of the past will likely increase in costs as the climate changes much like a revolving line of credit tends to grow faster over time when a balance is carried.

7.2.2 Recognition Justice

At its core, recognition justice deals with respect. Spurlock et al. (2022) presents the concept as a demand to recognize that divergent views exist on the best pathways for energy project development and strategies to address issues of climate justice. Those views reflect the unique, diverse backgrounds of these communities who present the perspectives and opinions reflective of their histories. Incorporating those voices in the energy transition is critical to ensuring policymakers implement project development that seeks to serve all. Equitable outcomes begin with the recognition that disenfranchised communities will require the effort to enfranchise and empower their members to ensure their histories and perspectives are heard in a meaningful way.

Recognition justice seeks to provide for fair representation, safety, and the general creation of an environment that is welcome to all. McCauley et al. (2013) identified issues of recognition injustice in terms of how policy might treat those characterized as “energy poor” with the classic example of the behaviors of elderly household energy use. Looking at the overall higher average energy use, United Kingdom policymakers viewed the issue as an education problem where the assumption was that elderly people don’t understand the long run impacts of small behavior changes. The authors revealed that nudging behaviors in elderly households required acknowledging that older people need warmer houses for their health and well-being. Strategies for changing behavior are more effective when normative behaviors within the community, culture, or ethnicity are recognized.

7.2.3 Procedural Justice

Spurlock et al. (2022) presents procedural justice as essentially the effort to include all voices. They posit that disadvantaged communities are overburdened and underserved and their disenfranchisement can only be corrected for when their voices are intentionally included in the start-to-finish process of project and policy development. In other words, stakeholder engagement must be done early and often to ensure their priorities are codified in the priorities of the project or policy.

Procedural Justice takes a more holistic view of outcomes from the perspective of group perception. Researchers have broken the concept of procedural justice down into three core areas of effect. The voice effect is the positive behavior observed in communities engaged with a decision-making process when the individual feels heard. The effect of dignitary process is best described as respect. When an individual’s dignity is preserved, the community buy-in to the procedure grows. Finally, the fair-process effect describes the positive community behaviors that arise when the group perceives the existence of procedural justice. In a sense, the effect of fair process augments the effects of the dignity process and the power of voice (Lind & Earley, 1992).

7.3 ENERGY JUSTICE

Under-girded by the three tenets of distributional, recognitional, and procedural justice, energy justice acts as a guiding concept for activism (McCauley et al., 2013). A large literature review of the energy justice topic (Qian et al., 2022) shows that the recent growth in focus on energy justice has quickened in pace with renewable energy driving interest. Debating what energy justice is has been a robust area of discussion for researchers, but there exists a few core concepts that underpin most approaches. At its heart, energy justice deals with the issue of energy poverty and is an offshoot of the broader focus into environmental justice (Iwin´ska et al., 2021).

While the focus on the justice of energy distribution is not new, it has grown in salience as the public increasingly accepts the need to engage in a transition away from fossil fuels. Using energy justice as a decision-making framework, Iwin´ska et al. (2021) outlined the focus of this literature as one that seeks to consider how the policy-making framework for energy generation and consumption can be more ”fair”. In this sense, energy justice is a tool to guide policy design. Specifically, Iwin´ska et al. (2021) considers the energy justice concept as a ”boundary object” whose conceit is to accelerate the inculcation of these principles in policymaker innovation and across all cultural boundaries. Much like a change agent. On the other hand, these authors debate the merits of treating the concept as a standard rather than a boundary object. Standards on energy justice would more easily be incorporated into policy in tractable forms that are quantitative and qualitative, though likely at the loss of a unifying definition (Iwin´ska et al., 2021).

Digging beyond the core tenets of energy justice, Sovacool & Dworkin (2015) acutely characterizes the conceptual metrics by which broader approaches to energy justice may be measured. Those included the need to measure the costs communities face with a special emphasis on the level of inequity across communities relative to the distribution of these costs. Complementing that, Sovacool & Dworkin (2015) also identifies the need to distribution of benefits to these same communities. As simple as the idea sounds that you would measure the costs *and benefits* to disadvantaged and disenfranchised communities, historical focus has more often been focused on mitigating or compensating for costs than on how project design can seek to benefit disenfranchised communities. Their very disenfranchisement may relegate them to an ex-post consideration (when considered at all) which highlights costs over benefits. The simple statement that benefits be considered alongside costs may act to nudge the focus back towards ex ante planning.

Sovacool & Dworkin (2015) lists procedure as the critical element that can act to bridge the cost - benefit foci. The process by which energy project development flows can be exclusive by nature which would naturally prohibit the participation of disenfranchised communities who, again by definition, are not enfranchised to advocate as robustly as the enfranchised communities. By shaping the process from the core tenet of inclusivity, the authors reveal what is obvious: process matters. From start to finish, intentionally shaping a process that seeks to actively embrace inclusivity must be the goal if some semblance of fairness is to be achieved in energy project planning.

Iwin´ska et al. (2021) also did an excellent job of outlining the various foci of energy justice research so far. The dominant topic recently has been on renewable energy which would make sense as the energy transition efforts have driven the growth of interest in energy justice as a topic. Summarizing the rest of the subtopics of energy justice in broad terms, the rest of the research has fallen within the realm of energy poverty, energy policy, law, and governance.

Results from the transition away from fossil fuels are producing differentiated outcomes that vary by community. Energy justice studies reveal that some are clearly benefiting from the increased access to renewable energy technology and opportunities while others assume the burdens of change. Those communities that seem to be accruing the adverse health outcomes and increased cost of cleaner technology are the same historically disenfranchised peoples who often fail to reap the job gains and regional economic growth opportunities of change. It has been found that nonprofit organizations tend to lead in the effort to ameliorate for these inequitable outcomes (Carley et al., 2021)

Pellegrini-Masini, Pirni, & Maran (2020) makes the case that the prevalence of energy justice definitions inhibits the capacity of policymakers to deploy these concepts towards the greater good. They highlight several useful, but nuanced, approaches with Guruswamy (2010) underscoring the "energy oppressed poor" as those suffering from an inequitable distribution of energy as a resource which is innately about distributional justice.

7.4 ENERGY POVERTY

Poverty is a dominant issue that arises often in research focused on energy. As policies are implemented to attenuate the worst effects of climate change, the focus on carbon emissions as a flow and stock necessarily highlights how these costs are going to be born geospatially. Carbon mitigation policies themselves also present societal costs that are unequally burdening communities based on how much of the remaining carbon budget impoverished communities might need. But at its heart, energy justice is an issue of economic opportunity as access to safe, affordable energy is a necessity to meet basic human needs and pursue economic growth opportunities (Piwowar, 2022).

Bouzarovski & Petrova (2015) identifies the criteria and conditions that drive energy poverty as the material and/or social deficit in energy services accrued by communities. The authors outline two key issues. First, deficits in domestic energy access and supply are the direct result of ineffective socio-technical mechanisms that fulfill energy demand at the household level of energy services such as heating and lighting. Second, "vulnerability thinking" often drives or exacerbates these outcomes. That is that the perceived likelihood of becoming impoverished can drive outcomes, frame processes, and generally lead to the undesired outcome as a result of historical perceptions or perspectives (Hall et al., 2013).

While the concept of energy poverty has traditionally been about distributive justice and the provision of warmth in the Rawlsian term of 'primary goods', Walker & Day (2012) argues that procedure and recognition play as important a part in perpetuating states of energy poverty within disadvantaged communities.

Okushima (2021) attempts to measure what the author refers to as the basic carbon needs (BCN) of a community. These are the total carbon emissions an individual community might need in order to attain what the authors called an "adequate level of domestic energy services". Their case study of Japan highlighted that BCN varied based on differences in several factors within a community including the type of domestic dwelling, community demographics, and the variation in climate characteristics across regions. Affluence allows people to rely on energy sources alternative to carbon and can change BCN. Moreover, Okushima (2021) found that balancing the ability of all communities to meet their energy needs with decreases in their BCN is the critical factor for achieving some equitable progress on climate change.

The increased importance of energy poverty may have increased in recent years as a function of our increased attentiveness to climate change risks, but Campbell (1993) points to the 1970*s* oil crises as the flux point at which energy poverty challenges to political stability were revealed. Those latent risks to social cohesion were evident in communities dominated by lower incomes, access to inefficient heating technology, and sub-standard governmental standards for housing insulation. But, the sudden rise in oil prices catalyzed those latent risks into active disruptions that were exacerbated as policymakers introduced mechanisms to ration supply.

Campbell (1993) identifies this conceptual term 'poverty' as an issue that confounds action on the problem of energy poverty. The dominant conceit of poverty is a state of being. Poverty is associated as a multi-generational condition without tangible points of action to take. To most, the state of poverty is a state of being. This is a challenge without boundaries and that amorphousness tends to overwhelm policymaker action especially when considering the issue as multi-generational. Think of it as a state of terrorized paralysis where there are so many ways to tackle poverty, the policymaker and public discourse could second guess every action.

Energy poverty, on the other hand, is an infrastructure problem that capital expenditures can directly cure because household expenditures on fuel are quantifiable and therefore, a threshold exists in theory where energy poverty begins and ends Campbell (1993). The author points to Boardman (1987) that posited 10% was the threshold of concern for energy poverty - a metric several others have adopted (Green et al., 2016; Lloyd, 2006; Lesser, 2015). Spending above that proportion of household income indicated a state of energy poverty whereupon the cost of basic and necessary fuel consumption was a burden. This necessitates the fundamental question: how do you measure energy poverty?

Follow on research has expanded on this effort to create a metric of threshold for energy poverty. While some countries have adopted specific metrics for measuring and comparing energy poverty (Faiella & Lavecchia, 2021), there is no clear consensus on best practices. Chapman & Scannell (2005) developed the Affordable Warmth Index (AWI) based on the calculation of energy ratings to identify sources of energy that are in need of efficiency investments by policymakers and households. Several others have made contributions with Siksnelyte-Butkiene et al. (2021); Thomson & Snell (2013); Heindl (2013); Miniaci et al. (2014); Okushima (2016) and Brunner et al. (2012) as a starting point of examples.

Regardless of the methodology for measuring energy poverty, the fundamental issue at hand is that deficits in affordable warmth change the fundamental routines of peoples suffering from energy poverty that are pervasive drivers of household outcomes (McCrone, 2015). The lack of affordable energy can bind communities to a lack of economic opportunity as they attempt to accommodate for energy deficits or their high costs which tend to affect minorities and people of color more intensely.

The myriad impacts of energy poverty on health are too numerous to cover in this document, but Faiella & Lavecchia (2021) outlines several and offers a guiding light on the topic. Overall, households with limited incomes are energy poor and suffer from negative health outcomes because of it (Thomson et al., 2017). One is excess deaths during winter time McAvoy et al. (2007) with the elderly particularly at risk (de'Donato et al., 2013) and increasing seasonal variation due to climate change compounding these risks (Healy, 2003). For healthcare systems, this increased seasonal health risk can reduce economic activity and reduce the integrity of the broader healthcare system (Wells, 2007) with compounding effects to the system over time (Torjesen, 2012).

Negative outcomes tend to accumulate across multiple community context, but their effect is not felt in isolation. Rather, these negative community outcomes tend to have cumulative effects that interact and compound each other with the risk of cointegrated impacts higher with liquified natural gas project development (Gislason & Andersen, 2016).

7.5 JUST ENERGY TRANSITIONS

The energy transition presents a generational opportunity to make significant progress in ameliorating historical injustices (Wang & Lo, 2021). As technology has evolved and capital flowed into large-scale energy infrastructure investments, a concerted effort to increase the accrual of economic and social benefits from projects in disadvantaged communities would prove fruitful. Equally possible is the ability to start mitigating the systemic costs that have continued to impact these same communities from historical decision-making.

The articulation of energy transition goals varies significantly across the research literature in their articulation, but they tend to boil down into a handful of broad topics. They include poverty reduction (Lo & Broto, 2019; Koehn, 2008; Colenbrander et al., 2017), ameliorating historical energy injustices (Jasanoff, 2018; Delina & Sovacool,2018; Carley & Konisky, 2020), and opportunities for economic growth (Yang et al., 2018; Ehresman & Okereke, 2015). Wang & Lo (2021) argues that the energy transition is an apt vehicle for fixing historical wrongs if it can simultaneously account for environmental costs disadvantaged communities already suffer from, the reality that climate change will likely exacerbate these pre-existing environmental costs, and a decision-making process steeped in the tenets of energy justice.

Pellegrini-Masini, Pirni, Maran, & Kl¨ockner (2020) attempts to prioritize the approach towards justice and the energy transition across four planes. First, the tradeoff in intergenerational outcomes and opportunities must be a prominent concern of policymakers. This gets to the core reason we care about mitigating climate change. That is that the generations that follow us should be provided the opportunity for growth and well-being that is at least commensurate with today's generations. Second, building out policy that considers the energy vulnerability will help to prevent the transition from being a zero-sum game where regional economies that rely on fossil fuels are left behind. In this sense, energy projects will benefit vulnerable communities. Third, transforming the social self-image of communities whose cultural identity is tied to fossil fuels must be considered in order to avoid confusing the energy transition with an attack on disadvantaged communities. Finally, the unavoidable damage to local communities must be accounted and compensated for.

The ability to move forward into a new energy landscape that is sustainable is a direct function of policymakers ability to avoid repeating historical injustices which makes the need for justice frameworks to be a bedrock in planning for the transition (Wang & Lo, 2021; Williams & Doyon, 2019). Using this as an opportunity to reduce pollution and shore up tax revenues through clean energy projects should be a primary goal with economic opportunity forefront (Henry et al., 2020).

Pai et al. (2020) provides the framework for researchers to consider strategies for a 'just transition'. That is one that preserves the well-being of these communities that are reliant on fossil fuel use. Preserving the human capital of these communities is a critical goal for ensuring the energy transition provides opportunities for all to shift with the policy. The authors summarized over a dozen requirements that would facilitate policymaker efforts to ensure for a just transition. First and foremost is an intentional effort for long term planning with routine efforts to conscientiously engage with the affected communities. Historically disenfranchised communities of people must be actively welcomed into the discussion early and often to be re-franchised and ensure their voices are heard (Weller, 2019). Interestingly, the term 'just transitions' has been found to have originated within community organizing efforts centered on labor unions (Eisenberg, 2018).

7.6 Fossil Fuel Employment

As we shift away from a carbon-intensive economy, the delicate issue of fossil fuel employment arises. Specifically, regions in which fossil fuel use has dominated employment opportunities may find that extractive or refining industries are the core driver of local economic growth.

Under these conditions, zero-sum mentalities can quickly gain traction. The capacity to politicize energy transition debates is high (N. Healy & Barry, 2017) with carbon intensive firms in a unique position to rally action against clean energy projects (Goods, 2022) as a tradeoff between community well-being and climate policy. There is some merit to this concern from the community perspective as well. Female employment in the solar industry lags far behind male (Carley & Konisky, 2020) and disadvantaged or disenfranchised communities tend to bear a larger overall burden of costs even with cleaner energy projects (Brock et al., 2021). To the extent that governance strategies can acknowledge the dignity of historically disadvantaged communities and groups, then efforts to engage with them in energy transition and governance strategies will be more successful and less divisive (Grossmann & Trubina, 2021).

Unions are viewed as an amenable structure for elevating and empower the voices of disadvantaged communities in the energy transition (Pai et al., 2020; Newell & Mulvaney, 2013). One reason for this may be in the high unionization rate of fossil fuel industries (Pai & Carr-Wilson, 2018). Engaging with unions is in many ways a matter of practicality, but their pre-existing internal structures are built to advocate for their members make them a strong vehicle for working towards a just transition (Stevis & Felli, 2015).

Intentional efforts to diversify local economies would increase the resilience of local economies (Lobao et al., 2016). Notably, increasing the diversity of local economies is a positive regardless of the effort to transition away from fossil fuels. Any local economy highly dependent on one industry - particularly when that industry is as volatile as the extractive industry - would introduce a greater resilience supportive of regional growth (Freudenburg & Gramling, 1994).

Among the opportunities a just transition presents are the ability to reduce the gender gap in regions dominated by the fossil fuel industry, increase investment into local infrastructure, remediation of historical environmental damage, retraining the local workforce to 'skill up' the region's human capital, and shore up local government revenues through economic diversification (Pai et al., 2020).

In the end, just transitions are achieved when local voices are not just heard, but amplified, during the energy transition process. An unfortunate trend can play out that misses the mark on this issue where well-intentioned decisionmakers attempt to prescriptively advocate on behalf of disadvantaged communities. Often, policymakers advocate for the environmental protection of disadvantaged communities while neglecting to consider the calls for economic development emanating from those communities. A key example of that rests in the Canadian arctic where liquefied natural gas projects that could act as local development opportunities for increasing local incomes are prevented by national policies that have banned energy projects out of the best intentions. (Nicol & Barnes, 2019).

One obvious benefit of large-scale energy project development rests in the rents accrued from the project's completion. Treating these project benefits as a viable source of income that could be distributed to disadvantaged communities was explored in Chandrashekeran (2021). Honing in on indigenous populations in Australia subsequent to land repossession within Aboriginal populations, establishing property rights for historically disenfranchised populations is a key step in empowering collective negotiations for revenue sharing to fund reparations (Chandrashekeran, 2021).

7.7 Protests and Political Activism

Excluding communities creates risks not just for disadvantage populations, but for the completion of large-scale energy project development overall with potential violent outcomes (Temper et al., 2020). The perpetuation of community disenfranchisement leaves people with a sense that the only option available for advocacy is to organize and protest. The way in which narratives are framed matters a great deal with respect to facilitating buy-in by communities.

Janzwood & Millar (2022) provides the argument that the duality of natural gas - that it is simultaneously an accelerator of the transition as a baseline electricity input while its use ensures the perpetuation of carbon reliance - creates the conditions for interpretive politics to dominate discourse around the transition. This is especially true for LNG organizations planning large infrastructure projects (Korkmaz & Park, 2019) and when regional economies are reliant on fossil fuels or the topic of natural gas as a 'bridge fuel' is debated (Rosenbloom, 2018; Cha, 2020).

On the other side, anti-coal and anti-gas advocacy groups have proven their own capacity to organize effectively in developed economies (Durand & Keucheyan, 2022). Social movements such as a the "UK Rights to Warmth" in the United Kingdom have coalesced around the fight against entrenched energy poverty to some success (Walker & Day, 2012). Successful efforts to stop LNG export projects have been found even in fossil fuel friendly US state such as Texas (Garrett & Sementelli, 2021) with access to social media and the strategic deployment of online networks increasing their efficacy (Correa-Cabrera et al., 2022).

The willingness to protest varies across cultures. Whereas communities within the US that are at-risk of job losses from national policies might tend to view justice as a regional tug of war that *must be* fought, research into Chinese activism shows that the Confucian perspective on justice as a collective outcome whose goals are harmony between nature and humanity shifts the perspective of the debate at its core (Wang & Lo, 2022). However, a nation or region's reliance on fossil fuels is not a reliable indicator of attitudes towards natural gas and LNG projects. Case in point, protestors in Canada and Norway have vehemently advocated against the expansion of oil and gas exploration despite their deep reliance on oil and gas production for both economies (Harrison & Bang, 2022). It has also been found that protests can arise in areas where there is a history of oil extraction when unconventional natural gas exploration is proposed (Chailleux et al., 2018).

The politicization of energy infrastructure can result in starkly divided factions, but the common thread of discontent that binds pro- and anti-gas contingencies is rooted in process. Specifically, deficits in procedural and distributional justice tend to increase the likelihood of activism (Evensen, 2018; Temper et al., 2020).

7.8 Energy Governance and Just Transitions

Governance structures play a vital role in the pursuit of energy project development and the transition away from fossil fuels, but their ability to provide for an equitable or just transition is not guaranteed (Moss, 2009). Incorporating the concept of just outcomes begins with the governance structures of energy project development and planning (Newell & Mulvaney, 2013). Those who are in the position of governance are in a position of authority to inculcate more equitable outcomes to benefit disadvantaged populations (Florini & Sovacool, 2009).

As Florini & Sovacool (2009) points out, governance is not simply ’government’. Governance is an activity in which governments participant and hold sway over, but there is far more to governance than just government. Governance is a framework for creating and maintaining processes to the implement policy. This framework is the conduit for participation that brings together government, intergovernmental organizations, private sector market participants, and communities to collectively manage a process that ideally serves all groups.

Governance is necessary as a result of two issues with which economists often wrestle. That is that society is not capable of ensuring equitable access to public goods without some overarching set of rules to facilitate that outcome and a governance structure to provide oversight over implementation. Beyond this, any economic or social activity has a tendency to create what economists call ’externalities’. That is, there are unintended results that can occur indirectly from the consumption of goods or social interactions. The decommissioning of a coal power plant is a prime example of the need for governance to protect the public’s well-being from externalities such as the risk that an idle power plant becomes a source of a health risk to the community without intentional efforts to prevent that outcome. Governance structures are necessary to deal with these two conceptual issues because there is no economic incentive to do so (Florini & Sovacool, 2009).

Perspectives can clearly vary within communities and that variation can affect governance structures Wang & Lo (2021). In studying international natural gas markets, Norouzi (2022) notes that the heterogeneity of individual members within a collective community implies that international natural gas market outcomes are heavily influenced by individual preferences within any collective. Community engagement is important, but it is not the magic elixir that solves the problem by itself. Ciplet & Harrison (2019) identifies three conflicts that emerge in the effort to provide for an energy transition. Those are the conflict between inclusivity and sustainability where inclusive processes that invite community engagement require more time to complete projects. The conflict between sustainability and the need to recognize the unique value system for each community increases the complexity of sustainability goal pursuits. Finally, the conflict between equity and sustainability means that the distribution of costs and benefits can be in conflict with project performance.

The impact of a region's political economy can also clearly drive outcomes. Inequality is a multi-dimensional concept that varies across countries and individuals (Laurent & Zwickl, 2021). As Soviet bloc nations exited the Union of Soviet Socialist Republics (USSR), the effort to integrate into energy markets within the European Union (EU) revealed that variations in culture and geography dominated some preferences in energy project outcomes with respect to energy justice (LaBelle, n.d.). On the other hand, a study of sub-Saharan African nations revealed a positive relationship between democracy, energy justice, and growth (Opoku & Acheampong, 2023). Cultural differences aside, income and wealth inequality may drive many of the outcomes. Studies of EU attitudes towards sustainability policies show that 41% country-level variance in negative attitudes is correlated with differences in wealth and income (Pellegrini-Masini et al., 2021).

In short, the lack of consideration for energy justice issues within the global framework of energy governance will likely just perpetuate historical disadvantages within communities (Symons & Friederich, 2022). This is a function of existing power structures within our current governance structures. Beyond that, Symons & Friederich (2022) shows that the political sovereignty of communities making independent decisions over energy project development will always result in outcomes that serve each group's self-interest and ignore the externality problems. Without intentional adjustments to governance that deal with these structural problems, the current paradigm will continue to create winners and losers and perpetuate the current disenfranchisement of some communities.

Good governance strategies for energy project development require support from the government, reliable capital and operational funding, diversification goals for the economy, and coalitions that are diverse (Wang & Lo, 2021; Cha et al., 2020). Finally, the creation of ownership stake opportunities at the onset of project development for disadvantaged communities is critical to ensuring that the tradeoffs between disenfranchised communities and the regional benefits of energy projects ameliorate losses. This is a more nuanced issue than a first glance would imply. Greater rates of acceptance have been found to exist within communities with larger ownership stakes in energy projects (Hogan et al., 2022).

7.9 Sustainable Development

The desire to balance environmental protection and economic development in disadvantaged communities has led to the championing of a concept called sustainable development. Summarized broadly, the idea is to balance the needs to current generations without harming the well-being of future generations. Within this movement, the needs of today's impoverished communities are heavily weighted under the theory that gains in wealth and income of today's generation beget gains in tomorrow's generation. In other words, the benefits of economic development compound over generations (Poppel, 2018).

In practical use, the concept of sustainability can be vague (Grossmann et al., 2022). One oft-missing area of focus is the tradeoff between environmental protection advocacy for disadvantaged communities and advocacy with these same communities for energy justice and sustainable development. The concept of embedded sustainable development outlines criteria for energy project development to be measured in terms of how energy justice efforts compare to the energy privilege of communities (Ciplet, 2021).

In 2015, United Nations outlined a list of 17 Sustainable Development Goals that define the focus of sustainability as a practice ("United Nations", 2015). Oriented towards 2030 outcomes, the 17 outcomes broadly fall into the Barbier (1987)'s canonical "three systems" approach to process development. Those are the environmental, social, and economic systems. Broadly speaking, the 17 goals break down into the promotion of clean water and sanitation services alongside sustainable cities and sustainable economic growth with full employment as well as the sustainable development of natural resources. They also promote the end to food insecurity and poverty, greater levels of societal health and well-being, lifelong inclusive/equitable educational opportunities and gender equality as well as strong judicial and governmental institutions. Finally, United Nations (2015) advocates for the proactive implementation of climate change policy that results in infrastructure resilience where communities have access to reliable and affordable clean energy.

Cherepovitsyn & Evseeva (2020) proffers several criteria to promote sustainable development within the context of LNG project development in the arctic - an area currently receiving a great deal of attention for energy development projects. The authors note the importance of sustainable development in the arctic as it is home to over 20% of the world's hydrocarbon resources. To promote sustainable outcomes, they propose seven criteria of sustainable development goals:

- Project development must minimize environmental impacts at the construction and operation site.
- Natural resource use should be efficient.
- Local community support is paramount as is the effort to preserve indigenous culture and heritage.
- Long-run regional economic gains that benefit and reflect stakeholder expectations should be prioritized.
- Larger Infrastructure development goals are achieved.
- Innovations to industry technology are achieved.
- Strengthening the regional LNG market relative to the global network is achieved.

Note that while the framework for measuring outcomes by Cherepovitsyn & Evseeva (2020) focuses on the arctic, this approach may be prudent for any LNG project development strategy. As such, the seven points have been modestly edited to apply more broadly.

7.10 Conclusion

Historical disenfranchisement of communities has often resulted in the creation of "winners" and "losers" with respect to policy impacts. To the extent that the existence of disadvantaged communities can be attributed to those policy impacts, they are the result of the lack of inclusivity in the planning and implementation processes of project development. As we embark on the energy transition away from a carbon intensive economy, the chance to right those historical wrongs presents itself.

The calls to advocate for energy justice during this transition have grown as the salience of climate change threats grows. Achieving a 'just transition' is largely a functioning of process. The once in a lifetime opportunity to restructure those processes around the core concepts of distributional, recognitional, and procedural justice is significant. Re-framing the foundations upon which our critical infrastructure is built to bring diverse voices and stakeholders to the planning table will help to ensure that our best laid plans produce results that facilitate the growth of all, not just some.

To do so, there is a need to accept the existence of the frictions innate to energy justice and energy poverty. Providing for economic growth opportunities in carbon-intensive regional economies is as paramount a priority as the need for ensuring reliable, affordable, and clean energy is to those suffering from a historic lack of energy access. This may require adjusting how we measure the benefits and costs of our largescale energy infrastructure investments. The implementation of the Biden administration's Justice 40 initiative had initiated that effort.

This chapter provides the framework for pursuing these inclusivity goals in its discussion of energy justice and energy poverty. The energy transition is presented as a catalyst for pursuing change with the intended outcome being a just transition for all. In the end, the vehicle for applying our energy justice and energy poverty goals rests in the inclusive design of our energy governance structures.

Less research into these topics in the space of natural gas and LNG market development has been penned than will be in the future. The literature base is strong and growing. As researcher focus evolves, this chapter hopes to have provided the broad conceptual framework necessary to engage in meaningful growth. Beyond this, it is critical to note that pre-existing community outcomes have a tendency to drive future outcomes. With intentionality, the authors of future research can help to ameliorate for those historical disenfranchisements and provide a framework the kind of shared prosperity that induces strong growth for all.

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From: Jamieson, Matthew B.
Sent: Thu, 24 Aug 2023 12:41:50 +0000
To: Matthews, Howard Scott (CONTR); Skone, Timothy
Cc: Priyadarshini; Whiston, Michael M (NETL)
Subject: RE: Updated draft of LNG report (SA 02.021.003.002)
Attachments: lng_nems_gcam_08212023_mbj.docx

I'm only about half-way through, but I wanted to get something out before Tim starts his day and for a couple of them, maybe not wait until later. I think I'll be done taking a look by lunch, just have a couple meetings to get through.

Matt Jamieson
Department of Energy National Energy Technology Laboratory
Strategic Systems Analysis & Engineering
Senior Life Cycle Analyst
412.386.7610 (direct) | (b) (6) (mobile)

From: Matthews, Howard Scott (CONTR) <Scott.Matthews@netl.doe.gov>
Sent: Wednesday, August 23, 2023 4:53 PM
To: Jamieson, Matthew B. <Matthew.Jamieson@NETL.DOE.GOV>; Skone, Timothy J <timothy.skone@hq.doe.gov>
Cc: Priyadarshini <Priyadarshini@netl.doe.gov>; Whiston, Michael M. (CONTR) <Michael.Whiston@netl.doe.gov>
Subject: Updated draft of LNG report (SA 02.021.003.002)

Tim and Matt:

As discussed earlier in the week, attached please find an updated draft of the LNG report, which is complete in terms of sections and conclusions. I know we lose both of you to some extent this week, and want to put it in front of you to get feedback. I wasn't sure that Tim could see NETL Sharepoint.

As Matt and I only agreed on the alignment method for the other industrial energy use sector yesterday, and it is core to all of the calculations, the report does not have all of the different results re-run, esp for the different IPCC methods. What is contained is largely the same values we looked at last week, to help with consistency and thoughts we had at the time (these were generally for AR5-100).

In the meantime, we pushed to get text, context, and synthesis done – the additional "results" arent going to be significantly different than the IPCC values contained in this document – there will just be more of them to show. I also borrowed Harsh for an hour to help get landed LNG numbers to Rotterdam to help with the contextual comparison of the adders to the NETL g CO_2e/MJ results. I think it's a better discussion now, and helps with the questions Tom had on last week's call.

Of course any edits are welcomed, but please focus on the "takeaway messages". I tried to get in what we had discussed but don't assume I nailed it. Again, the numbers might change a little but at a high level, they're set (e.g., negative adders). Of course we are working to QA and update all of the numbers in the meantime, and will send along as soon as we have them.

One last thing – please advise on if/when/how we should be willing to share our text with others in FECM other than Tim (who are clamoring to see what we have). I defer to you on this.

Scott

H. Scott Matthews
NETL Support Contractor
Department of Energy National Energy Technology Laboratory
scott.matthews@netl.doe.gov

DRAFT-DELIBERATIVE-PREDECISIONAL

To: Matt Jamieson and Tim Skone
From: Scott Matthews, Michael Blackhurst, and Priyadarshini
Date: August 23, 2023
RE: Comparing the NETL Baseline Results and Framework with that of the Global Change Assessment Model (GCAM)

Note: this memo is now morphing into the imminently needed LCA section/chapter that will appear in the LNG report.

Some values in this memo are still using AR5-100 even though the intent is by default to use AR6. Edits added soon, but will of course not change much. Have been focused on the messaging that FECM and others need to see.

Recall that the current report outline has separate sections for methods and results. Have added "Results" subheaders for what of this text will be in which spot of the report.

1 Introduction

The goals of the Life Cycle Analysis (LCA) component of this project are twofold. First, to help contextualize how the other results of this study (i.e., NEMS and GCAM models) connect to past studies of US natura gas (NG) and and liquefied NG (LNG) operations. Second, to leverage the results of the other models to quantitatively represent the international ~~global~~ global warming potential (GWP) consequences from changes in quantities of US exported LNG.

In support of the first goal, the LCA component of this project will:

- Assess whether NEMS results suggest significant changes in domestic supply (and thus, resulting in potential future upstream GWP intensity or emissions changes)
- Assess the level of difference between GCAM's representation of NG sector emissions vs. existing DOE/NETL studies
- Align GCAM and NETL results for consistent representation of the global ~~natural gas~~ NG supply chain

In support of the second goal, the LCA component of this project will:

- Develop a quantitative "market effect adjustment factor" that represents the consequences of additional export volumes of US LNG, such as how additional available quantities of natural gas led to changes in the energy sectors of countries that purchase the LNG and the country that exports the LNG. These consequential effects will be estimated by tracking differences in global GHG emissions and quantities of LNG exported from the GCAM model scenarios, and will be assessed in addition to the existing quantitative estimates of the upstream natural gas production.
- Use speciated GHG emissions estimates from the GCAM model to estimate the social costs of carbon in the seven scenarios using methods developed by the White House and DOE

Past studies done by NETL on NG and LNG have largely been techno-economic analyses focused on expected costs per unit delivered (landed) or attributional life cycle analyses that only estimate the emissions and other impacts associated with units of NG/LNG delivered. These LCA studies are limited in that they have not, to date, considered the *consequences* of delivering LNG, such as how domestic or foreign energy markets may be affected by increasing the supply of natural gas (e.g., whether, given additional supply, natural gas-fired power plants in Europe might take market share from other types of electric plants). Such market-based effects could lead to consequential increases or decreases in greenhouse gas (GHG) emissions. In this study, these consequential effects will be estimated by tracking differences in global ~~CO2~~ GHG emissions and quantities of LNG exported from the GCAM model scenarios.

In this section, we detail the various existing representations of the natural gas supply chain within the context of the NETL natural gas model and the GCAM model. The purpose of documenting these representations is to subsequently assess the differences in the two models at more detailed levels.

1.1 Past NETL Natural Gas Life Cycle Reports

As shown in the top half of Table 1, the NETL Natural Gas model (cite 2020 version here) is separated into five stages that generally align with categories used in other federal efforts such as the US EPA's Greenhouse Gas Reporting Program (GHGRP) and Greenhouse Gas Inventory (GHGI) products. Results of this model are provided for two scopes: Production through Transmission (e.g., for large scale industrial users, like power plants directly connected to a pipeline), and Production through Distribution (e.g., for residential or smaller industrial users where the gas is delivered through smaller distribution pipelines). Results are provided for various techno-basins of production, regions, and US average production, using a variety of IPCC Assessment Report Global Warming Potential (GWP) values.

In addition, past work by NETL has modeled the additional processing stages to produce and deliver LNG, adding another four stages in the bottom half of Table 1. The data for these unit processes are based on peer-reviewed industry data representative of 2017 technology.

Commented [SM1]: Let's also verify year/etc basis of this data (2017?). also can you grab those and paste in below? We can ask Harsh to verify if needed.

Commented [P2R1]: I think its 2020?

Commented [SM3R1]: The year of the study is 2020, but the data is older. Not sure of year.

Table 1. Natural Gas and Liquefied Natural Gas Life Cycle Stages

Stage Name	Description
	Natural Gas Production Only Stages
Production	Drilling and construction of conventional and unconventional wells (e.g., from hydraulic fracturing), and extraction of gas, including liquids unloading operations
Gathering and Boosting	Movement of natural gas from wells via gathering pipelines and delivered to treatment and/or processing plants. Boosting

	systems may include compressors, dehydration, and pneumatic devices and pumps.
Treatment and Processing	Removal of impurities and compression of input gas to meet transmission pipeline standards. May include acid gas removal (AGR), dehydration), NGL recovery, etc.
Transmission and Storage	Construction of pipelines, and movement of bulk quantities of natural gas in large pipelines to large users or city gates for subsequent distribution. Typically includes compressor stations along pipelines. Storage includes insertion of gas into units such as underground storage facilities as well as additional gas processing and compression after removal from storage before injection into the transmission pipeline network.
Distribution*	Movement of gas from transmission or storage facilities to city gates for subsequent to smaller consumers via small diameter pipelines. (*may or may not be included depending on scope)
Additional Stages to Produce and Deliver LNG	
Liquefaction	Pre-treatment of gas, liquefaction to low temperatures and storage
Loading/Unloading	Process to load (and unload) LNG to and from tankers to facilities
Ocean Transport	Shipment of LNG on ocean-going vessels of varying technology types to distant ports for subsequent regasification. Depending on technology, may use LNG as fuel.
Regasification	Regasification of LNG and injection into transmission pipelines.

Commented [SM4]: Pri - can you grab these and paste in?

Commented [PSR4]: Is this what you were referring to in the comment at the first line of this section?

Destination Transmission / Distribution	Similar processes as described above, and not functionally different than as described for the natural gas only part.

Quantitatively, NETL[a] has estimated ranges of greenhouse gas emissions by species, and by stage, for the domestic natural gas supply chain as shown in Figure 1. Given the scope of domestic natural gas production through the transmission stage, the mean US average total CO2-equivalent emissions are about 7.44 g CO2e/MJ (IPCC AR6, 100-year basis), with a confidence interval of the mean of 4.6-11.1 g CO2e/MJ. While not shown here, this report also estimated GWP intensity of natural gas extraction in different geographic regions of the US, which have higher or lower intensity, as compared to the US average.

[a] (Natural Gas Extraction and Power Generation: U.S. 2020 Emissions Profile[2]) – be sure to cite specific Appendix E file?

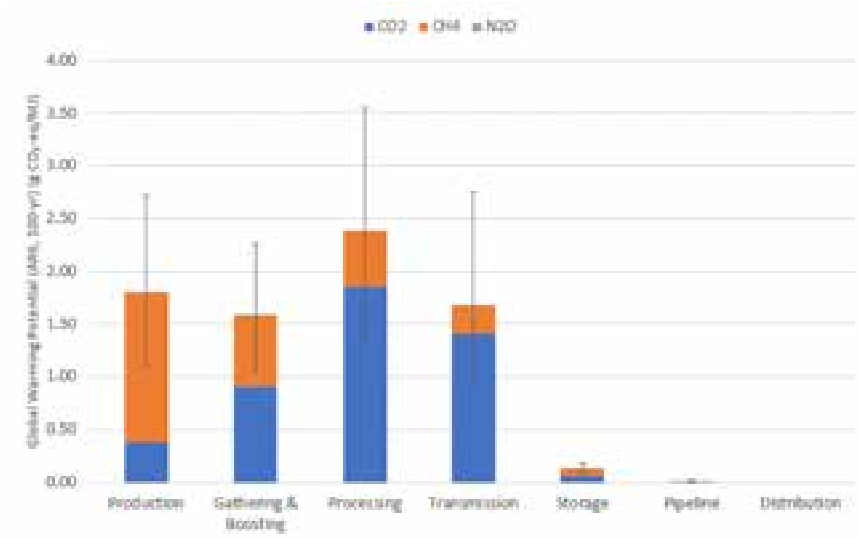

Figure 1. Life cycle GHG emissions from the 2020 U.S. average NG supply chain (Source: NETL 2023)

Past work by NETL has also estimated the greenhouse gas emissions implications of the additional stages to produce and deliver US average LNG around the world. While these values are estimated on a per-MJ delivered basis, their presentation is complicated by the variability associated with the distance shipped, which can be large in many cases (LNG shipped relatively short distances has a significantly smaller GWP footprint than that shipped long distances). Using data from the 2019 NETL LNG report (cite), and adjusting to the basis here, LNG delivered from New Orleans to Rotterdam (8,990 km) would be expected to result in 17.9 g CO2e/MJ delivered (IPCC AR6, 100-year basis). In short, the additional processes and natural gas needed to liquefy, ship, and regasify natural gas to Rotterdam adds about 10 g CO2e/MJ delivered, which is more than double the impact of merely producing the gas and transmitting it to large scale users domestically (of 7.44 g CO2e/MJ, given above). The GHG emissions intensity result on a per MJ NG delivered to liquefaction plant basis is 7.44 g CO2e/MJ (AR6, 100-yr) but accounting for NG losses that occur in the downstream stages results in a higher volume of NG upstream, leading to an upstream emissions intensity of 8.44 g CO2e/MJ NG

~~(AR6, 100-yr)~~ delivered to power plant (AR6, 100-yr). Given the many possible delivery routes and distances for such LNG, these specific results are intended only to provide contextual perspective of the GWP intensity of the added LNG stages.[b]

Commented [JMB6]: Thought it was important not to break up the functional unit here.

The NETL natural gas model and the LNG report are attributional studies of the domestic natural gas system. The results seek only to identify and attribute the emissions associated with various unit processes that create them. These methods do not seek to more broadly consider the consequences of what happens when additional volumes of US natural gas ~~is~~are produced and delivered across the world, or, in other words, the market-based effects of producing domestic natural gas and exporting it.

In this project, the NEMS and GCAM models seek to represent economic and environmental changes associated with the defined changes in US LNG exports. The GCAM model explicitly estimates global GHG emissions effects, separated by region. Thus, an initial area of exploration of this study was to compare the upstream natural gas GWP impacts as represented in the GCAM model, which has similar but different data sources (compared to NETL). To maintain consistency with past NETL work used by DOE in support of natural gas and LNG export decisions, GCAM emissions results can be assessed and quantitatively adjusted to rationalize the emissions estimates of the two models.

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[b] Results from 2019 LNG report (cite!), Exhibit A-2, adjusted from g CO2e/MWh to g CO2e/MJ using heat rate of 145 kg natural gas/MWh, and higher heating value of 54.3 MJ/kg.

2 Model Comparisons

2.1 NEMS v/s NETL

The NEMS modeling done in this project focused on domestic changes that would be expected to occur in the seven Scenarios modeled. The NEMS chapter of the report has already detailed its high-level results. Not previously shown, but of interest to the LCA section of the project, was whether the regional extraction mix of natural gas would be expected to change over time. This is relevant since if the NEMS results suggested that production would be expected to shift significantly from the current mix of regions, and especially if to distinctly higher or lower intensity regions, then this GHG intensity would be something to consider in the results.

Results

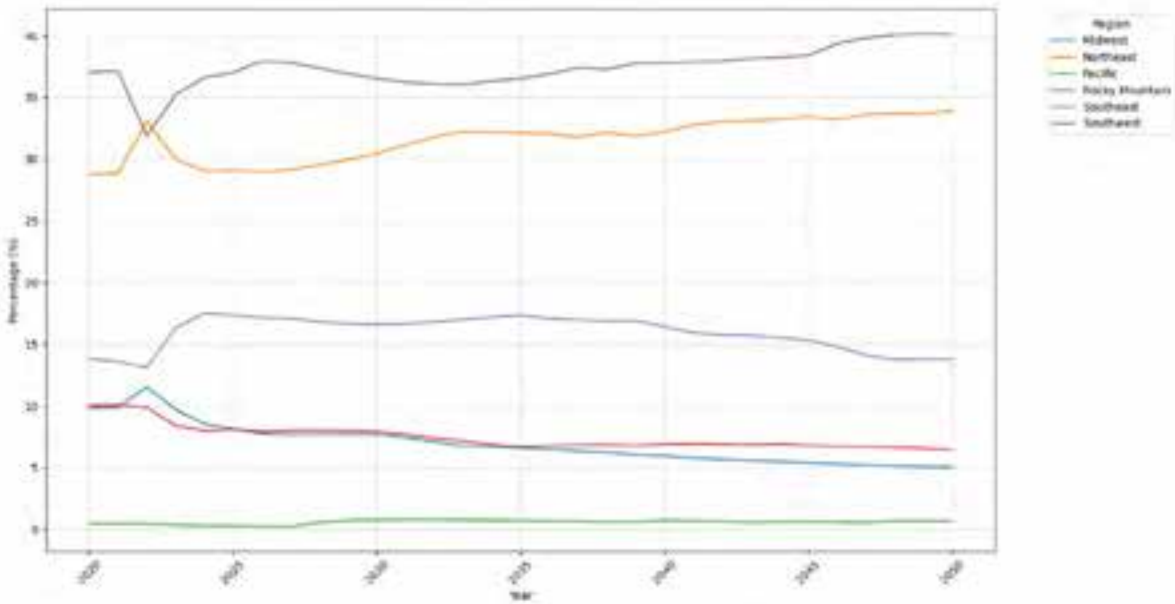


Figure 2. Dry Production percentage time-series for each region

Using data generated by the NEMS modeling results, Figure 2 shows the percent of natural gas dry production for each region of Scenario 1 as compared to total production in a specific year between 2020 to 2050. A state-based natural gas dry production (excluding the extraction losses) rate in a million cubic feet was taken from this data and every state was assigned to one of the six regions (Midwest, Northeast, Pacific, Rocky Mountain, Southeast, Southwest). Further aggregation of the production rates is performed to get values for every unique region. The same process was done for the other Scenarios.

The region-specific production data between 2020 to 2050 is used to calculate the percentage production within a region based on the total production across the US for a given year. Regional GWPs for 2020 from the 2020 NETL model were multiplied with the region-specific yearly production rates to estimate US weighted-average annual GWPs between 2020 through 2050. Figure 3 shows

Commented [JMB7]: I think there needs to be explicit discussion about mapping the NEMS regions to NETL techno-basins. Probably the most transparent way to provide this is a table showing the mapping.

these values for all Scenarios. A limitation of this analysis is that GWP values by region were only available for the year 2020, as such the results should be interpreted as an index as compared to the estimated 2020 values as opposed to predictions of future GWP.

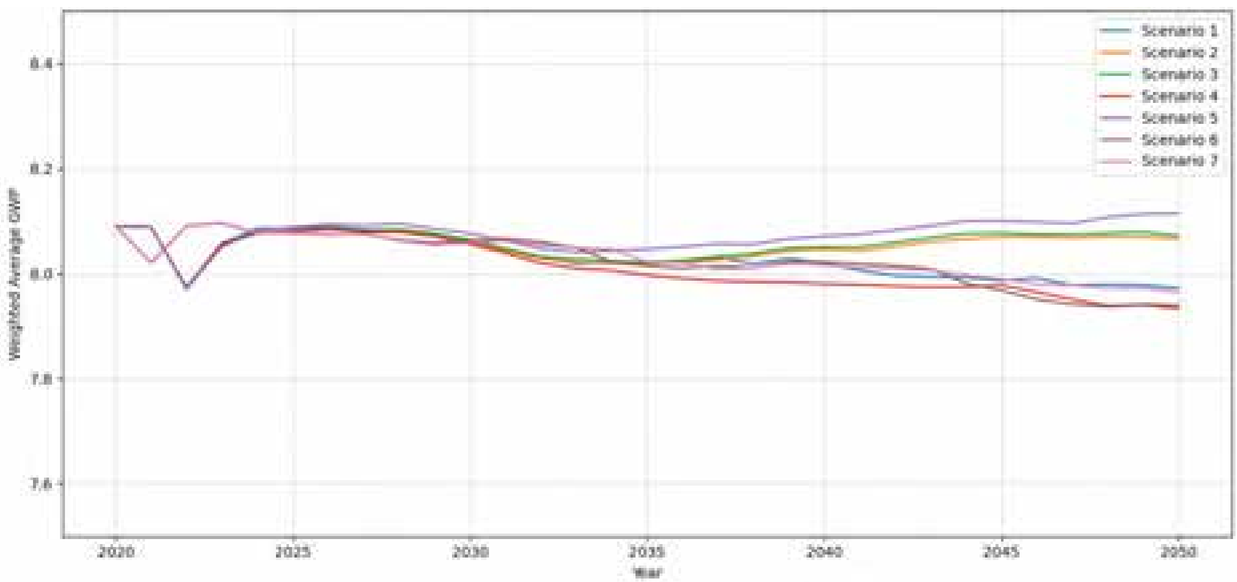


Figure 3. Estimated US Average GWP (Scenarios 1 to 7), Production through Transmission (2020 - 2050)

Overall, Figure 3 suggests that the ~~expected~~ NEMS-modeled changes in domestic production by region across the seven Scenarios are not expected to have a significant effect on the ~~expected~~ GWP intensity of domestic production (given the 2020 data on GWP by region).

2.2 Comparison of GCAM and NETL estimates of GHG emissions of the natural gas sector

In the GCAM model, economic activity (and its GHG emissions) is represented by sectors and technologies, and their respective inputs and outputs, for particular years and scenarios. Across all years and scenarios, GCAM has 105 discrete sectors, 377 discrete technologies, and many sector-technology pairs that can vary depending on the model configuration. However, only a subset of these are relevant to the scope of this LCA-focused effort (i.e., with a focus on the natural gas sector).

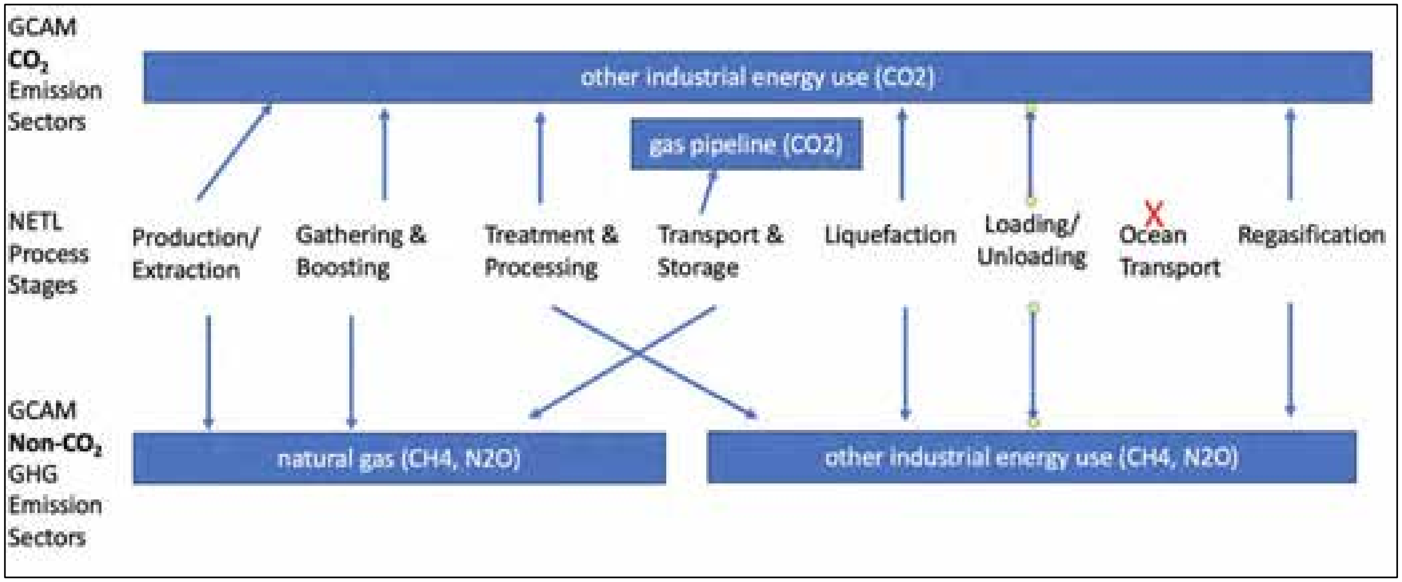
Detailed investigation and discussion with the GCAM team during this project identified that only three sectors in the GCAM model encompass the greenhouse gas emissions of the natural gas sector - *natural gas, gas pipeline*, and *other industrial energy use* (see Appendix for more detail). Using the basis of process stages as represented in the NETL Natural Gas model, Figure 4 shows the relevant GCAM sectors that represent CO_2 and non-CO_2 emissions. While the overall GCAM model has 16 species of GHG emissions, for the three sectors above relevant to the upstream natural gas sector, only emissions of CO_2, CH_4, and N_2O are available.

In short, all stages are explicitly represented in GCAM except for Ocean Transport. These (relatively small, in global terms) emissions should also be contained within GCAM's "other industrial energy use" sector. However, due to data limitations, it was deemed not possible to explicitly extract these emissions from that sector. GCAM results will not explicitly represent LNG transport via ocean, and as such our comparisons will focus on production of natural gas domestically rather than LNG delivered around the world. This is a limitation of this comparative analysis.

Commented [P8]: Is there a specific number of sector-technology pairs?

Commented [SM9R8]: On second thought I dont think we need to specify the NN pairs in the model, we will just worry about the ones we need to.

Figure 4: Mapping of NETL Natural Gas Stages to GCAM Sectors (<u>can discuss a better graphic</u>)



Results

(note, are updating the table below based on various things, but wanted to maintain the values we had been using in past discussions to ensure previous messaging discussions were still valid. Intent though will be to have AR6 values shown)

Table 2 shows the emissions intensities of the various GCAM sectors for the *USA* region for the three natural gas-relevant sectors identified above. Note that the *gas pipeline* and *natural gas* sectors are assumed to wholly incorporate natural gas-relevant emissions, and so total emissions are shown, as extracted from GCAM model output result files.

However, the *other industrial energy use* sector contains a diverse set of activities that are connected to overall GDP of each region, making it relatively difficult to explicitly identify emissions related to natural gas. As further detailed in the Appendix, for this sector, 2015 IEA data on energy use by oil and gas production activities used by the GCAM modeling team were provided and utilized to apportion GHG emissions associated with natural gas activity. This IEA data is aggregated into oil and gas activities such as "Extraction, Gathering and Boosting", "Processing", and "Liquefaction and Regasification". However, a challenge is that the IEA data represent extraction of both oil and gas resources, which were variously allocated for the natural gas products. Given the lack of data on liquefaction and regasification in the 2015 IEA data (including for the U.S.), emissions from those activities ~~is~~are excluded from the analysis, consistent with the focus on upstream natural gas effects.

The emissions intensity cells in Table 2 show the underlying equation used to generate values, where the numerator is the total emissions from the GCAM model for the USA region for Scenario 1 for the year 2020 for each of the three greenhouse gases (if available), normalized by the total production of US natural gas from the GCAM model in 2020 (33.13 EJ). Units of emissions intensity follow those internal to the GCAM model, which are Tg CO_2 equivalent per Exajoule, which conveniently are equal to g CO_2e/MJ, the same units as used in the NETL model. Thus, the bottom rows in Table 2 show comparisons to those of the NETL model.

Table 2: GCAM Emissions Intensities for Sectors (S1, 2020, USA region)

			Estimated GCAM Emissions Intensity (Tg CO_2e / EJ, g CO_2e / MJ) [IPCC AR5 100 yr]		
GCAM Sector	**NETL LCA Stage**	**Comments/Potential mapping inaccuracy**	**CO_2**	**CH_4**	**N_2O**
gas pipeline	Transmission and Storage	Have assumed this fully represents the Transmission sector equivalent to the NETL NG model.	38.2/33.1 = 1.15	-	-

<table>
<tr><td>natural gas</td><td>Production + Gathering & Boosting + Processing</td><td>From discussions with GCAM team, this sector represents all other natural gas related activities, thus the mapping to all other NETL stages other than transmission.</td><td>-</td><td>171.4/33.1 = 5.17</td><td>.016/33.1 = 4.8 E-4</td></tr>
<tr><td>other industrial energy use (technology = gas or gas cogen)[a]</td><td rowspan="3">For 2015, Extraction, Gathering & Boosting</td><td rowspan="3">Estimates from IEA energy shares.

For technology = gas or gas cogen, all GHG emissions allocated to the natural gas product.

For technology = refined liquids or refined liquids cogen, GHG emissions are allocated to the natural gas and crude oil products on an energy (EJ) produced basis from GCAM output data.

2015 crude oil – 24.7 EJ, natural gas 26.2 (50%)
2020 – 22.5, 33.1 (NG is 60%)</td><td>81.3/33.1 = 2.46</td><td>.04/ 33.1 = .001</td><td>xx</td></tr>
<tr><td>other industrial energy use (technology = refined liquids and refined liquids cogen)[a]</td><td>16.3/33.1 = 0.5

50% = 0.25
60% = 0.3</td><td>.4 / 33.1 = .01</td><td>xx</td></tr>
<tr><td>other industrial energy use (electricity)[a]</td><td>-</td><td>-</td><td>-</td></tr>
<tr><td colspan="3">Total GCAM by gas (including <u>only 50% gas shares of other ind above</u>)</td><td>= 1.15 + 2.46 + .5 = 4.23</td><td>5.17 + .0005 + .005 = 5.18</td><td>4.8 E-4</td></tr>
<tr><td colspan="3">Total GCAM (including <u>only 50% gas shares of other ind above</u>)</td><td colspan="3">9.41</td></tr>
</table>

Subtotal from NETL Model, Processing through Transmission boundary	**7.58**

Overall, on an IPCC AR5 100-year basis, the best guess of upstream emissions in the GCAM model are about 9.41 g CO2e/MJ, which are slightly higher than those of the NETL model for the boundary of production through transmission to large end user (7.58 g CO2e/MJ). Given the use of similar data sources throughout the GCAM model, emissions in the natural gas sector should be adjusted by a factor of 9.41/7.58, or 0.8 (a 20% reduction) to maintain consistency with past NETL work, so this alignment factor is used for all regions and for all years in the model. As implemented, this adjustment factor of 0.8 is directly applied to GHG emissions in all regions for the *natural gas* and *gas pipeline* sectors as they wholly related to natural gas activities.

For the *other industrial energy use* sector, the adjustment is complicated by the fact that the sector includes many activities beyond natural gas. If the adjustment factor were wholly applied to the GHG emissions of the sector, then the total emissions in GCAM would be reduced for both natural gas and non-natural gas activities. A compromise was made to estimate the total needed reductions associated with only natural gas emissions for each region, and to reduce the emissions of the other industrial energy use sector by that amount. While this does not achieve a full alignment of these associated emissions, it avoids the outcome where the sector's emissions are reduced for all of the other activities.

Commented [JMB10]: So we obviously couldn't apply 0.8 * industrial energy use. Did we end up doing "industrial energy use" - "industrial energy use" * "IEA energy share" * 0.8? I think that's how this reads.

These adjustments to emissions from all regions, all scenarios, and all years were applied to existing GCAM model results (i.e., the GCAM model was not re-run or scenarios optimized based on these adjustments). For context, in the provided GCAM results for Scenario 1 in Year 2020, total global GHG emissions are approximately 53,000 Tg. The post-processing of the GCAM model results of the *gas pipeline* and *natural gas* sectors reduces emissions by about -30 and -200 Tg CO_2e, respectively, when considering those of Scenario 1 in the Year 2020. Post-processing adjustments of the GCAM model results of the *other industrial energy use* sector reduces emissions by about -100 Tg CO_2e when considering those of Scenario 1 in the Year 2020. Overall, the adjustments for these three sectors have the equivalent effect of reducing emissions in the GCAM model by about 0.6% (in Scenario 1 in the Year 2020).

This same process was undertaken for each IPCC GWP method, and the resulting alignment tables and adjustment factors are provided in the Appendix.

Not finished yet: Effects of future methane mitigation in GCAM and other needed alignment….

2.2.1 Market Adjustment Factors

In order to quantify the broad and global market effects associated with increasing exports of US LNG, a method was proposed to use the adjusted GCAM results to estimate the change in global GHG emissions per unit of LNG exported between various scenarios. This market adjustment factor (MAF) is defined as:

$$MAF_{scenario\ n} = \frac{Global\ Emissions_{scenario\ n} - \ Global\ Emissions_{scenario\ 1}}{US\ LNG\ Exports_{scenario\ n} - US\ LNG\ Exports_{scenario\ 1}}$$

and represents a ratio of the change in GHG emissions for a given scenario compared to a base scenario, versus the change in US LNG exports between the same two scenarios. For example, a comparison of Scenario 2 vs. Scenario 1 would have n=2, and compare the differences in GCAM values for these two scenarios. This MAF can be calculated for every model year (2015-2050), and can use linearly interpolated values for the non-model years.

MAFs for Scenarios 2-5 can all be found versus a baseline of Scenario 1, although Scenarios 3-5 represent significantly different global economic outcomes and should be interpret more cautiously. Similarly, the MAF for Scenario 7 was deemed most relevant to be compared against Scenario 6.

Results

Note that unlike the natural gas system-specific emission comparisons and adjustments discussed above which focus on CO_2, CH_4, and N_2O, GCAM estimates emissions of sixteen GHGs and all are included in this study. MAFs were calculated using the post-processed NETL-adjusted GCAM results described previously. A particular Scenario MAF is calculated for every year 2015-2050 (including the linearly interpolated non-model year results), but is summarized by only the aggregate values over the time horizon of the model (i.e., the MAF for S2 versus S1 uses as inputs to the equation the total difference in annually-estimated global emissions over the 35-year period divided by the total difference in annually estimated exported LNG over the period). Results were created for various IPCC GWP values.

Currently included are those for IPCC's 5th Assessment Report, for 100-year time horizons, including the effects of climate carbon feedback (see Appendix for GWP values used). *Only IPCC AR5-100 are shown here at this point (QA'ing and checking the others).* The Appendix shows the annual summaries of GHG emissions, LNG export volumes, and deltas compared to baselines for each underlying year of GCAM model runs. Given the many different aspects of the global economy modeled in the various project Scenarios, results are carefully distinguishes into separate tables.

Figure 5 shows the market adjustment factors for Scenario 2 (vs. Scenario 1), which vary from -5.9 to XX on a 100-year time horizon and from XX to XX on a 20-year time horizon. Also included is a summary reminder of the differences in the modeled scenarios (e.g., where S1 is the baseline and S2 modestly adds an economic solution for LNG exports, making a direct comparison of the two appropriate).

Figure 5: Market Adjustment Factors for Scenario 2 vs. Scenario 1 Using Various GWP Values from IPCC

	Results (g CO_2e/ MJ)				
MAF Case	**AR5, 100 with ccf**	**AR5, 20**	**AR6-100**	**AR6-20**	**Scenario Difference**
Scenario 2 vs. Scenario 1 (S2-S1)	-5.9	xx	xx	xx	Adds economic solution for LNG exports.

Figure 6 shows the market adjustment factors for Scenarios 3-5 (vs. Scenario 1). Also included is a summary of the differences in the modeled scenarios (where S1 is again the baseline). As noted above, Scenarios 3-5 represent additional and substantial packages of assumptions as compared to S2, and as a result should not be directly compared to the MAF for S2 or S7 (and MAFs for S3 through S5 should be carefully compared to each other). Nonetheless, the results of these three MAFs represent relative bounds on the MAFs across a wide range of economic assumptions such as inexpensive renewable energy and high global population growth.

The MAFs for Scenario 3 vary from 231 to XX on a 100-year time horizon and from XX to XX on a 20-year time horizon. The MAFs for Scenario 4 vary from -0.4 to XX on a 100-year time horizon and from XX to XX on a 20-year time horizon. The MAFs for Scenario 5 vary from -38 to XX on a 100-year time horizon and from XX to XX on a 20-year time horizon.

Figure 6: Market Adjustment Factors for Scenarios 3-5 vs. Scenario 1 Using Various GWP Values from IPCC

	Results (g CO_2e/ MJ)				
MAF Case	**AR5, 100 with ccf**	**AR5, 20**	**AR6-100**	**AR6-20**	**Scenario Difference**
Scenario 3 vs. Scenario 1 (S3-S1)	231	xx	xx	xx	Adds economic solution for LNG exports, also higher assumed population growth outside of the U.S.
Scenario 4 vs. Scenario 1 (S4-S1)	-0.4	xx	xx	xx	Adds economic solution for LNG exports, but constraints on importing and exporting natural gas with a global focus to maximize use of domestic gas.
Scenario 5 vs. Scenario 1 (S5-S1)	-38	xx	xx	xx	Adds economic solution for LNG exports, but lower capital costs for renewable energy technologies.

Figure 7 shows the market adjustment factors for Scenario 7 (vs. Scenario 6), both of which represent significantly different energy and economic investments in support of a low-carbon global economy through climate policies. The Scenario 7 MFAs vary from -3.5 to XX on a 100-year time horizon and from XX to XX on a 20-year time horizon.

Figure 7: Market Adjustment Factors for Scenario 7 vs. Scenario 6 Using Various GWP Values from IPCC

	Results (g CO_2e/ MJ)				
MAF Case	**AR5, 100 with ccf**	**AR5, 20**	**AR6-100**	**AR6-20**	**Scenario Difference**

Scenario 7 vs. Scenario 6 (S7-S6)	-3.5	xx	xx	xx	S6 1.5°C pathway, economic solution for LNG exports

2.2.2 Interpretation of Market Adjustment Factor Results

On an IPCC AR6 100-year basis, for S2-S1, the MAF result is approximately -6 g CO2e/MJ, or put another way, would almost fully compensate for the +7.4 g CO_2e/MJ upstream natural gas production values estimated by the NETL NG model. For S7-S6, the MAF result is slightly lower (about -3.5 g CO_2e/MJ), but would reduce the domestic upstream NG GWP impacts by about 50%.

Considering the broader life cycle perspective of natural gas delivered to other parts of the world as LNG, and considering the 17.9 g CO_2e/MJ for LNG from New Orleans to Rotterdam described earlier, the market adjustment factors for S2-S1 would reduce the GWP impact of that delivered LNG by about one-third. Using the MAF for S7-S6 would reduce the GWP impact by about one-fifth.

Following the broader conclusions already suggested by the GCAM section of the report on the GHG effects of the various scenarios, the market adjustment factors estimated by this project, using the adjusted GCAM simulation results, suggest that the consequences of increasing US LNG exports broadly lead to decarbonization in the global economy.

These results are important as modeled, but also should be presented with various caveats:

- The GCAM simulations represent broad modeling of the global economy, and despite tremendous sectoral detail, can not represent all technologies, or fully encapsulate all activities or market effects
- The results are aggregate in relation to estimated future volumes of exported LNG from the US in the context of a global model. They represent overall expected effects and not those of individual shipments or authorizations of LNG. It is not possible to conclude that every MJ of exported LNG from domestic gas sources would directly lead to lower GHG emissions results when supplied around the world.

2.2.3 Social Cost of Carbon

Following previous DOE and NETL studies, the speciated emissions of CO_2, CH_4, and N_2O from each Scenario were estimated as Social Costs of Carbon (SCC) using the spreadsheet-based DOE NEPA Social Cost Estimating Tool. This tool estimates annual and cumulative social costs of emissions of each gas in future years using discount rates of 2.5, 3, and 5 percent.

Adjusted global GCAM emissions from 2020 (the first year able to be modeled in the tool) through 2050 are used as inputs. Unlike other GHG results shown above which vary based on use of IPCC GWP factors, the tool provides just a single set of social cost estimates. The Appendix shows the underlying annual and cumulative social costs from each scenario. Table X shows the cumulative present values of SCC (in millions of dollars)

Table 3: Summary of Social Cost Estimates for the Adjusted GCAM Scenarios

Scenario	**SC-CO2**			**SC-CH4**			**SC-N2O**			**SC-Total**		
	5%	**3%**	**2.5%**	**5%**	**3%**	**2.5%**	**5%**	**3%**	**2.5%**	**5%**	**3%**	**2.5%**
1	$xx											
2												
3												
4												
5												
6												
7												

Considered together, these social cost estimates show the dramatic reductions in social costs that occur in Scenarios 6 and 7 compared to the other scenarios, given their focus on meeting the 1.5 degree C targets and investments in renewable energy around the world. Scenarios 1-5 have similar and higher social costs as compared to Scenarios 6 and 7.

Do we want line graphs? One for each discount rate for all 7 scenarios?

Scroll down to see Appendix (also still in progress).

Appendix to LCA section (not very well organized yet, mostly stuff pasted here)

NEMS GWP Analysis

The code used for this analysis can be mathematically represented as a series of summations, percentage calculations, and weighted averages.

1. **Filtering Columns:**

$$\boldsymbol{actual\_years} = \{\boldsymbol{column} \mid \boldsymbol{column} \notin \{\boldsymbol{Region}', '\boldsymbol{state}', '\boldsymbol{State}'\}\}$$

2. **Calculate the Yearly Totals Across All Regions:**

   Let D be the dataset (or matrix) of all data. For each year y in actual_years:

$$\boldsymbol{yearly\_totals}[\boldsymbol{y}] = \sum_{i=1}^{n} D_{i,y}$$

   Where n is the number of regions.

3. **Calculate the Percentage for Each Region Compared to the Yearly Total:**

   For each year y in actual_years and for each region r

$$\boldsymbol{percentage\_df}_{r,y} = \left(\frac{\boldsymbol{D}_{r,y}}{\boldsymbol{yearly\_totals}_{[y]}}\right) \times \mathbf{100}$$

4. **Transform Data to Long Format:** This step reshapes the dataset, converting it from wide format to long format. It's a structural transformation, not a mathematical operation.

5. **Weighted Average Calculation:** For each year y in $actual\_years$:

$$weighted_{averages[y]} = \sum_{i=1}^{n}\left(GWP_{i,2020} \times \frac{percentage\_df_{i,y}}{100}\right)$$

Where $GWP_{i,2020}$ is the GWP value for region i in the year 2020.

3 GLOBAL CHANGE ASSESSMENT MODEL – DATA INPUTS TO LCA

The GCAM model is an input-output-based model primarily represented by sectors and technologies and their respective inputs and outputs for particular years and scenarios. Across all years and scenarios, GCAM has 105 discrete sectors, 377 discrete technologies, and many sector-technology pairs that can vary depending on the model configuration. However, only a subset of these are relevant to this analysis (i.e., with a focus on the natural gas sector).

We used R code explicitly developed for this project to process the CSV file results provided by PNNL for the various Scenarios (1-7 and years modeled. Specifically, we were provided data files described in Table 4.

Commented [P11]: Is there a specific number of sector-technology pairs?

Commented [SM12R11]: On second thought I dont think we need to specify the NN pairs in the model, we will just worry about the ones we need to.

Table 4. Provided set of GCAM Data Documentation

File	Data Represented
co2_em_tech_2023.06.22	Provides data showing CO_2 emissions in megatons per year ($MtCO_2/yr$) for various sectors, energy sources or "technology" for 6 different scenarios across each of 37 regions.
co2_seq_tech_2023.06.22	Provides data showing CO_2 emissions in megatons per year ($MtCO_2/yr$) for various sectors, energy sources or "technology" for 6 different scenarios across each of 37 regions.
non_co2_em_tech_2023.06.22	Provides data showing non-CO_2 emissions in Gigagrams (Gg) equivalent to metric kilotons or 1,000 metric tons, for various sectors, energy sources or "technology" and 6 different scenarios across each of 37 regions.
inputs.by.tech_2023.06.22	Provides detailed information about energy consumption and capacity in different regions, sectors along with specific technologies and years. It can be used to analyze and understand the energy landscape, make projections, and assess the impact of various factors on energy consumption and capacity (sub-sector is not applicable in this dataset).

outputs.by.tech_2023.06.22	Reports the energy production within the various regions, by sectors, (sub-sector is not applicable in this dataset) along with specific technologies and years.
luc_em_2023.06.22	contains information about CO2 emissions (in million metric tons per year) for different regions and years.
Columns	**Description**
scenario	scenario or context for which the data is provided such as "S1: Existing Capacity," which suggests that the data corresponds to the existing capacity or infrastructure in the region.
region	This column specifies the geo-political region under consideration.
sector	This column categorizes the different sectors or areas of activity for which carbon dioxide emissions are being measured, e.g., “agricultural energy use”, “cement”, “air_CO_2”, etc.
sub-sector	Within each sector, there may be further divisions or subcategories to specify the specific aspect of the sector being measured, e.g., "mobile”, "stationary," etc. indicating different types of energy use within a single sector
technology	This column identifies the specific technology or energy source being utilized within the subsector. For example, "refined liquids" and "biomass"
year	The specific year or time period for which the CO2 emissions values are provided, this ranges from 2015 to 2050.
value	corresponding carbon dioxide emissions values for the given combination of scenario, region, sector, subsector, technology, and year. The values represent the estimated or projected amount of CO2 emissions in megatons per year in this

	specific file as depicted in the “Units” column (not mentioned separately in this table).
ghg	Refers to the greenhouse gas that is being emitted. It identifies the specific type of gas responsible for the emissions, e.g., HFC125, HFC134a, HFC143a, HFC23, HFC32, SF6, HFC245fa, HFC365mfc, C2F6, etc.
input, output	Additional details or characteristics about the technology or process. It helps to differentiate between different aspects or variations within a specific technology. Examples in the datasets include "elect_td_ind" (electricity transmission and distribution for industrial use) and "H2 wholesale dispensing" (hydrogen wholesale dispensing).

Amongst many data sources used in GCAM relevant to the natural gas and LNG, two are of importance – IEA data on energy and GHG emissions flows and the Community Emissions Data System (CEDS). We were provided detailed information on how the sectors of the NETL natural gas model may best align with those in the GCAM model, as in the table below.

Table XX

LCA stage	IEA energy flow	GCAM sector – energy & CO_2	CEDS sector	GCAM sector – nonCO_2
Extraction	Oil and Gas Extraction	other industrial energy use	1B2b_Fugitive-NG-prod	natural gas
Gathering and Boosting	Oil and Gas Extraction	other industrial energy use	1B2b_Fugitive-NG-prod	natural gas
Processing	Gas works	other industrial energy use	1A1bc_Other-transformation	other industrial energy use
Domestic Pipeline Transport [1]	Pipeline Transport	gas pipeline	1B2b_Fugitive-NG-distr	natural gas
Liquefaction	Liquefaction (LNG) / Regasification Plants	other industrial energy use	1A1bc_Other-transformation	other industrial energy use

Ocean Transport	International Marine Bunkers [2]	trn_shipping_intl [2]	1A3di_International-shipping	trn_shipping_intl
Regasification	Liquefaction (LNG) / Regasification Plants	other industrial energy use	1A1bc_Other-transformation	other industrial energy use
Pipeline Transport (at destination) [1]	Pipeline Transport	gas pipeline	1B2b_Fugitive-NG-distr	natural gas

Initially, to aid in identifying supply connections in the model, our team scripted separate R code to perform a "backward trace" of outputs of interest to see the inputs from sector-technology "pairs" and connect them throughout the upstream supply chain. The focus was on exemplar of pairs relevant to this analysis. In producing **Error! Reference source not found.**, a trace was run on the "delivered gas" output – the name of the output of natural gas that is ready to be used by large-scale customers such as power plants. Connected outputs and inputs can be seen in alternating rows (the blue arrow demonstrates the first such connection).

As shown in Table 5, our analysis uncovered the input-output pairs for each sector which is used to generate the emission values by dividing the GCAM output values with the total gCO2 equivalent for each sector. For comparability purposes, this value is further scaled based on scaling factors for both input and output to then generate the "scaled" emissions in gCO2e/MJ of output.

However, subsequent analysis has suggested that the trace algorithm is insufficient in tracking the entire upstream supply chain of activities, as there are various GCAM sectors that support natural gas activity but that are disconnected from the supply chain that is identified using the described algorithm. Nonetheless, the backwards trace example is maintained here to help to explain upstream supply chain connections in GCAM. Additional sectors from GCAM have been added at the bottom of Table 3 to account for these activities.

In the final columns of Table 3 are the global and US-only estimated GCAM emissions associated with natural gas for Scenario 1 for the Year 2020. (Note these are still using the mid-June values but are not expected to significantly differ in the final report).

Table 5. Traced GCAM CO2 and non-CO2 emissions for each sector and corresponding technology (Scenario 1, Year 2020, mid June results)

					Global GHG Emissions		**US GHG Emissions**	
Sector	**Technology**	**Input**	**Output**	**Description**	**CO_2 (Tg)**	**Non-CO2**	**CO_2 (Tg)**	**Non-CO2**

						(Tg)		(Tg)
Pairs from trace of NG sector								
Delivered gas	Delivered gas	Gas pipeline	Delivered gas	Seems to only be a market exchange sector	0	0	0	0
Gas pipeline	Gas pipeline	Gas processing	Gas pipeline	PNNL confirms this to be the expected pair, but IEA data may be spotty	186.2	0	38.2	0
Gas processing	Natural gas	Regional natural gas	Gas processin g	We assume this is intended to be comparable to gas processing in NETL model, but e-mail discussions with PNNL have indicated their scope is not as comprehensive as ours.	0	0	0	0
Regional natural gas	Domestic natural gas	Natural gas	Regional natural gas		0	0	0	0
Regional natural gas	Imported LNG	Traded LNG	Regional natural gas		0	0	0	0
Regional natural gas	Imported N American pipeline gas	Traded N. Amer	Regional natural gas		0	0	0	0

Commented [P13]: no more regional gas related sector (within scenario 1)

		pipeline gas						
Additional sectors separately identified as relevant								
Other industrial energy use	gas/gas cogen	N/A		Mentioned by PNNL as sector where emissions from extraction, G&B, processing, liquefaction, regasification would occur	255[c]	2.4	81.3	.03
Other industrial energy use	Refined liquids/refined liquids cogen				39[a]	5.7	16.3	.4
Natural gas	Natural gas			Identified by PNNL team	0	1164.2	0	171.5
Total (GCAM)					**480**	**1172**	**42.4**	**171.5**
Total (GHGI)							**36.5**	**185.3**

In terms of validation, the US values in Table 3 (which sum to 214 Tg CO2e) have been compared to the US EPA Greenhouse Gas Inventory (GHGI) for 2020. GHGI suggests that the total emissions of "Natural Gas Systems" are 36.5 Tg CO2 and 185.3 Tg of methane in CO2e (221.8 Tg CO2e total). Both the CO2 and non-CO2 values are within 10% of the EPA GHGI value. The total values differ only by about 5**%. Note however that the GHGI does not include CO2 emissions other than flaring in those of the "Natural**

[c] The values currently listed here are generated from allocations of energy use from the underlying IEA data – they will be replaced with direct estimates of GHG emissions when provided by PNNL. Total GHG emissions from GCAM in these two sector-technology pairs are 1514 and 731 Tg, respectively **and are NOT separated between oil and gas**. We do not expect significant differences when these are received.

Gas Systems" category – other non-flaring CO2 emissions from natural gas are in the broadly used "Fossil fuel combustion" category and can not easily be disaggregated.

In addition, the GCAM values can be normalized by the modeled final demands of natural gas produced in the US in S1/2020,

For appendix: In terms of comparing GCAM results of the natural gas sector with the NETL model, the emissions from appropriate total production value for a country is given by the output 'natural gas' from the sector-technology pair 'natural gas'. In 2020, the US total production in 'natural gas' is 33.13 EJ.

Old Mapping text

Given the information identified above, Table 4 demonstrates the intended correspondence of categories between the NETL NG model results and the GCAM model results.

Table 6. Potential Mapping of GCAM sector-technology pair with NETL stages

GCAM Sector	NETL LCA Stage	Comments/Potential mapping inaccuracy
delivered gas	NA	No CO2 or non-CO2 emission values for this GCAM sector (possible market exchange sector), therefore the mapping of this sector with the NETL stage isn't feasible.
gas processing	NA	No CO2 or non-CO2 emission values for this GCAM sector therefore the mapping of this sector with the NETL stage isn't feasible.
regional natural gas	NA	No CO2 or non-CO2 emission values for this GCAM sector therefore the mapping of this sector with the NETL stage isn't feasible. Also, "Region" in GCAM model stands for geopolitical region, which for the NETL stage was assumed as consisting

		of all the natural gas production through storage stages, since it considers the case of United States only.
gas pipeline	Transmission (Storage too?)	Have assumed this fully represents the Transmission sector equivalent to the NETL NG model.
natural gas	Production + Gathering & Boosting + Processing	From discussions with GCAM team, this sector represents all other natural gas related activities, thus the mapping to all other NETL stages other than transmission.
other industrial energy use (gas/gas cogen and liquids and liquids cogen)	WHAT HERE	WHAT HERE

Table 6 was the potential GCAM Sector mapping with NETL LCA Stages, prepared in order to analyze the relation between the two methodologies concerning natural gas processing, pipeline and distribution. The mapping is not accurate for reasons such as the geographical and technological context of data coverage and calculations within the two models/methodologies creates varying values (with vastly differing units) with do not perfectly align with one another in order to make a direct comparison, which was attempted in **Error! Reference source not found.**.

GWP Values used in this section (IPCC AR5, 100-yr with ccf)

1	CH4	36
2	CH4_AGR	36
3	CH4_AWB	36
4	N2O	298
5	N2O_AGR	298
6	N2O_AWB	298
7	HFC125	3691
8	HFC134a	1549
9	HFC143a	5508

10	HFC23	13856
11	HFC32	817
12	SF6	26087
13	HFC245fa	1032
14	HFC365mfc	966
15	C2F6	12340
16	CF4	7349
17	HFC43	164
18	HFC152a	167
19	HFC227ea	3860
20	HFC236fa	9810

S2-S1 – Detailed Background Data

	Scenario 1			Scenario 2				
year	global_lng	us_export_lng	global_co2_eq	global_lng_s2	us_export_lng_s2	global_tg_co2_eq	Δ_co2_eq	Δ _us_export_lng
2015	11.858	0.018	52488.031	11.858	0.018	52488.031	0.000	0.000
2016	13.753	0.538	53270.409	13.753	0.538	53270.409	0.000	0.000
2017	15.648	1.058	54052.788	15.648	1.058	54052.788	0.000	0.000
2018	17.543	1.578	54835.166	17.543	1.578	54835.166	0.000	0.000
2019	19.438	2.097	55617.545	19.438	2.097	55617.545	0.000	0.000
2020	21.333	2.617	56399.923	21.333	2.617	56399.923	0.000	0.000
2021	22.180	3.086	55750.013	22.180	3.086	55750.013	0.000	0.000
2022	23.027	3.555	55100.103	23.027	3.555	55100.103	0.000	0.000
2023	23.874	4.023	54450.193	23.874	4.023	54450.193	0.000	0.000
2024	24.722	4.492	53800.283	24.722	4.492	53800.283	0.000	0.000
2025	25.569	4.961	53150.373	25.569	4.961	53150.373	0.000	0.000
2026	26.428	5.372	53501.087	26.428	5.372	53501.087	0.000	0.000
2027	27.287	5.782	53851.802	27.287	5.782	53851.802	0.000	0.000
2028	28.147	6.193	54202.516	28.147	6.193	54202.516	0.000	0.000
2029	29.006	6.603	54553.230	29.006	6.603	54553.230	0.000	0.000
2030	29.865	7.014	54903.945	29.865	7.014	54903.945	0.000	0.000
2031	30.896	7.544	54924.381	30.811	7.462	54924.986	0.605	-0.082
2032	31.928	8.074	54944.818	31.756	7.910	54946.028	1.210	-0.164
2033	32.959	8.605	54965.254	32.702	8.358	54967.069	1.815	-0.246
2034	33.991	9.135	54985.691	33.648	8.806	54988.111	2.420	-0.328
2035	35.022	9.665	55006.127	34.594	9.254	55009.152	3.025	-0.411
2036	35.768	9.766	54910.372	35.911	9.996	54909.429	-0.943	0.230

2037	36.514	9.867	54814.616	37.229	10.738	54809.706	-4.910	0.871
2038	37.260	9.968	54718.861	38.546	11.481	54709.983	-8.877	1.513
2039	38.005	10.069	54623.105	39.864	12.223	54610.260	-12.845	2.154
2040	38.751	10.170	54527.350	41.182	12.965	54510.537	-16.812	2.795
2041	39.631	10.170	54466.246	42.361	13.561	54447.487	-18.760	3.391
2042	40.511	10.170	54405.143	43.540	14.157	54384.436	-20.707	3.987
2043	41.391	10.170	54344.040	44.719	14.753	54321.385	-22.655	4.583
2044	42.271	10.170	54282.937	45.898	15.350	54258.335	-24.602	5.180
2045	43.151	10.170	54221.834	47.077	15.946	54195.284	-26.550	5.776
2046	43.875	10.170	54100.302	47.928	16.271	54067.774	-32.528	6.101
2047	44.600	10.170	53978.770	48.779	16.597	53940.263	-38.507	6.427
2048	45.324	10.170	53857.239	49.629	16.922	53812.753	-44.486	6.752
2049	46.048	10.170	53735.707	50.480	17.248	53685.243	-50.464	7.078
2050	46.773	10.170	53614.176	51.331	17.573	53557.732	-56.443	7.403

S7-S6 – Detailed Background Data

	Scenario 6			Scenario 7				
year	global_lng	us_export_lng	global_co2_eq	global_lng_s2	us_export_lng_s2	global_tg_co2_eq	Δ_co2_eq	Δ _us_export_lng
2015	11.858	0.018	52488.032	11.858	0.018	52488.032	0.000	0.000
2016	13.753	0.538	53270.734	13.753	0.538	53270.734	0.000	0.000
2017	15.648	1.058	54053.436	15.648	1.058	54053.436	0.000	0.000
2018	17.543	1.578	54836.137	17.543	1.578	54836.137	0.000	0.000
2019	19.438	2.097	55618.839	19.438	2.097	55618.839	0.000	0.000
2020	21.333	2.617	56401.540	21.333	2.617	56401.540	0.000	0.000
2021	22.169	3.086	55465.461	22.169	3.086	55465.461	0.000	0.000
2022	23.005	3.555	54529.382	23.005	3.555	54529.382	0.000	0.000

2023	23.841	4.023	53593.303	23.841	4.023	53593.303	0.000	0.000
2024	24.677	4.492	52657.223	24.677	4.492	52657.223	0.000	0.000
2025	25.513	4.961	51721.144	25.513	4.961	51721.144	0.000	0.000
2026	25.931	5.067	51838.068	25.931	5.067	51838.068	0.000	0.000
2027	26.349	5.173	51954.992	26.349	5.173	51954.992	0.000	0.000
2028	26.766	5.278	52071.916	26.766	5.278	52071.916	0.000	0.000
2029	27.184	5.384	52188.840	27.184	5.384	52188.840	0.000	0.000
2030	27.602	5.490	52305.764	27.602	5.490	52305.764	0.000	0.000
2031	28.237	5.782	50941.678	28.237	5.782	50941.679	0.001	0.000
2032	28.871	6.075	49577.593	28.871	6.075	49577.595	0.002	0.000
2033	29.506	6.367	48213.507	29.506	6.367	48213.510	0.003	0.000
2034	30.141	6.659	46849.421	30.141	6.659	46849.425	0.004	0.000
2035	30.776	6.951	45485.335	30.776	6.951	45485.340	0.005	0.000
2036	31.740	7.481	44135.034	31.740	7.481	44135.038	0.004	0.000
2037	32.705	8.010	42784.733	32.705	8.010	42784.736	0.002	0.000
2038	33.669	8.539	41434.433	33.669	8.539	41434.434	0.001	0.000
2039	34.633	9.068	40084.132	34.633	9.068	40084.131	0.000	0.000
2040	35.598	9.597	38733.831	35.598	9.598	38733.829	-0.002	0.000
2041	36.181	9.712	37288.808	36.398	10.012	37287.814	-0.994	0.300
2042	36.764	9.827	35843.786	37.199	10.427	35841.799	-1.987	0.601
2043	37.347	9.941	34398.763	37.999	10.842	34395.784	-2.979	0.901
2044	37.930	10.056	32953.741	38.800	11.257	32949.769	-3.972	1.201
2045	38.513	10.170	31508.718	39.600	11.671	31503.754	-4.964	1.501
2046	38.673	10.170	30133.387	39.817	11.836	30127.643	-5.745	1.666
2047	38.833	10.170	28758.057	40.034	12.001	28751.532	-6.525	1.831
2048	38.992	10.170	27382.726	40.251	12.166	27375.421	-7.305	1.996
2049	39.152	10.170	26007.395	40.468	12.331	25999.310	-8.085	2.161
2050	39.312	10.170	24632.065	40.685	12.496	24623.199	-8.865	2.326

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From: Harker Steele, Amanda J.
Sent: Tue, 5 Sep 2023 22:14:16 +C000
To: Curry, Thomas; Skone, Timothy; Sweeney, Amy; Easley, Kevin
Cc: Robert Wallace; Adder, Justin (NETL); Francisco De La Chesnaye
Subject: LNG Regulatory Analysis Support - Task 4 Env. Review Update
Attachments: 9_5_23 Deliverable.zip

Hi Tom, Amy, Tim, and Kevin,

*DRAFT*DELIBERATIVE*PRE-DECISIONAL*

Please find the revised, consolidated version of :he Env. Review for Task 4 attached along with the comment response log in the attached .zip folder.

I hope you all have a good rest of the week! We look forward to getting your feedback on this version. Thanks!

Sincerely,

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ENVIRONMENTAL IMPACTS AND SOCIETAL CONSIDERATIONS ASSOCIATED WITH UNCONVENTIONAL NATURAL GAS

September 5, 2023

DOE/NETL-2023/4388

DRAFT DELIBERATIVE PRE-DECISIONAL

INTERNAL USE ONLY – NOT YET APPROVED FOR PUBLIC RELEASE

Disclaimer

Hartej Singh[1,2]*: Writing – Original Draft;* ***Robert Wallace***[1,2]*: Writing – Original Draft;* ***Odysseus Bostick***[1,2]*: Writing – Original Draft;* ***Nicholas Willems***[1,2]*: Writing – Original Draft;* ***Michael Marquis***[1,2]*: Writing – Original Draft;* ***Amanda Harker Steele***[1*]*: Writing – Review & Editing, Supervision*

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LIST OF EXHIBITS

ACRONYMS AND ABBREVIATIONS

API	American Petroleum Institute
AR5	IPCC Fifth Assessment Report
B	Billion
Bcf	Billion cubic feet
BLM	Bureau of Land Management
BP	British Petroleum
BTEX	Benzene, toluene, ethylbenzene, xylenes
Btu	British thermal unit
CAA	Clean Air Act
CBM	Coalbed methane
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CH_4	Methane
CMSC	Citizens Marcellus Shale Coalition
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_2e, CO_2-eq	Carbon dioxide equivalent
COGCC	Colorado Oil and Gas Conservation Commission
CRS	Congressional Research Service
CSU	Colorado State University
CWA	Clean Water Act
d	Day
DAC	Disadvantaged community
DOE	Department of Energy
DOI	Department of the Interior
DOT	Department of Transportation
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EPA	Environmental Protection Agency
EPCRA	Emergency Planning and Community Right-to-Know Act
EQ	Earthquakes
ESA	Endangered Species Act
FECM	Office of Fossil Energy and Carbon Management
FERC	Federal Energy Regulatory Commission
ft, FT	Foot
g	Gram
G&B	Gathering and boosting
gal	Gallon
GHG	Greenhouse gas
GHGI	Greenhouse Gas Inventory
GHGRP	Greenhouse Gas Reporting Program
GWP	Global warming potential
GWPC	Groundwater Protection Council
H_2S	Hydrogen sulfide
HAP	Hazardous air pollutant
HF	Hydraulic fracturing
HPh	Horsepower-hour
IOGCC	Interstate Oil and Gas Compact Commission
IPCC	Intergovernmental Panel on Climate Change
ISO	International Organization for Standardization
kg	Kilogram
kJ	Kilojoule
km	Kilometer
km^2	Square kilometers
kWh	Kilowatt hour
LCA	Life cycle analysis
LNG	Liquefied natural gas
m^2	Square meter
m^3	Cubic meter
MARAD	Maritime administration
Mcf, MCF	Thousand cubic feet
min	Minute
MIT	Massachusetts Institute of Technology
mg	Milligram
MJ	Megajoule
ML	Local magnitude
MM	Million
MMT	Million metric tons
Mw	Moment magnitude
MWh	Megawatt hour

NOx	Nitrous oxides
N_2O	Nitrous oxide
NEIC	National Earthquake Information Center
NEPA	National Environmental Policy Act
NETL	National Energy Technology Laboratory
NG	Natural gas
NGA	Natural Gas Act
NGL	Natural gas liquid
NORM	Naturally occurring radioactive material
NOx	Nitrogen oxides
NPC	National Petroleum Council
NPS	National Park Service
NSPS	New Source Performance Standards
NYSDEC	New York State Department of Environmental Conservation
O_2	Oxygen
OECD	Organisation for Economic Co-operation and Development
ONRR	Office of Natural Resources Revenue
OSHA	Occupational Safety and Health Administration
OPA	Oil Pollution Act
OSF	Oral slope factor
PADCNR	Pennsylvania Department of Conservation & Natural Resources
PADEP	Pennsylvania Department of Environmental Protection
PARETO	Produced Water Optimization Initiative
PHMSA	Pipeline and Hazardous Materials Safety Administration
PM	Particulate matter
ppm	Parts per million
PRV	Pressure release valve
POTW	Publicly owned treatment work
R&D	Research and development
RCRA	Resource Conservation and Recovery Act
RD&D	Research, development, and demonstration
REC	Reduced emissions completion
RFF	Resources for the Future
RFI	Request for Information
RfV	Reference value
RPSEA	Research Partnership to Secure Energy for America
RRC	Railroad Commission of Texas
scf	Standard cubic foot
SDWA	Safe Drinking Water Act
SF_6	Sulfur hexafluoride
SO_2	Sulfur dioxide
T-D, T&D	Transmission and distribution
T&S	Transport and storage
Tcf	Trillion cubic feet
tCO_2e	Tonnes carbon dioxide equivalent
TDS	Total dissolved solids
TexNet	Texas' Center for Integrated Seismicity Research
t NG	Tonnes natural gas
Tg	Teragram
tonne	Metric ton
U.S.	United States
UIC	Underground Injection Control
USFS	U.S. Forest Service
USGS	U.S. Geological Survey
VOC	Volatile organic compound
yr	Year

1 Introduction

The United States (U.S.) Department of Energy's (DOE) Natural Gas Regulatory Program is responsible for reviewing applications to import and/or export natural gas from and/or to foreign countries. An important dimension in considering whether to grant such authorizations is how the additional natural gas production and transport activities needed to support proposed actions may impact the environment.[a] Accordingly, potential impacts are factors affecting public interest during review of applications.

Although uncertainties exist regarding the exact amount and location of natural gas production or transportation that would occur in response to additional authorizations being granted, it is important that DOE provide the public and decision-makers with access to updated information regarding the potential impacts associated with such activities. Accordingly, DOE's National Energy Technology Laboratory (NETL) has prepared this update to the 2014 Addendum to Environmental Review Documents Concerning Exports of Natural Gas from the United States (hereafter the 2014 Addendum) (DOE, 2014).

As with the 2014 Addendum, this report provides a review of peer-reviewed, scientific literature related to the potential environmental consequences of unconventional natural gas production and related activities. As unconventional natural gas production represents the majority and a growing share of total U.S. natural gas production, the environmental impacts reviewed in this report relate primarily those associated with unconventional production activities.

The publications referenced build on a strong body of literature that traces the evolution of unconventional natural gas production techniques from their conceptual stages in the 1970s to the technology advancements that contributed to the shale gas boom of the early 2000s and the further development and recovery of additional unconventional natural gas resources (e.g., tight gas sands, coalbed methane [CBM], and associated gas recovered with shale oil) and to stimulate more production from conventional resources (National Petroleum Council [NPC], 2011 and Commonwealth of Pennsylvania, 2023a).[b,c]

This report summarizes published descriptions of the potential environmental impacts of natural gas operations within the lower 48 states as detailed by government, industry, academia, scientific, non-governmental, and citizen organizations. The sources cited are publicly available documents. While this report by no means represents an exhaustive list of the sources that discuss environmental consequences of natural gas production and related

[a] DOE is responsible for considering the environmental impact of its decisions on applications to export natural gas, including liquefied natural gas, to countries with which the United States has not entered into a free trade agreement requiring national treatment for trade in natural gas. (Applications for trade with free trade agreement countries are deemed to be in the public interest by statute.) DOE conducts environmental reviews under the National Environmental Policy Act and as part of its public interest review under the Natural Gas Act.

[b] In Pennsylvania, hydraulic fracturing, which is primarily used to produce natural gas from unconventional resources, has also been used to help stimulate production from conventional natural gas formations where reservoir characteristics do not otherwise permit sufficient production (Commonwealth of Pennsylvania, 2023a).

[c] A 2011 report by the NPC suggested hydraulic fracturing was responsible for the reversal of long-term declines from onshore conventional production of natural gas in the United States (NPC, 2011).

activities, NETL has determined the sources cited are representative of the literature, and no significant areas have been excluded.

In addition to providing a review of potential environmental impacts, this report also provides the public and decision-makers with information regarding the societal impacts from natural gas production and related activities, and how they can be considered.

Over the past decade, the focus on environmental issues has evolved with some interest in the public literature varying over time. Key research in some areas remains the same with minor to no new additions to the basis of scientific knowledge; in this situation, some historical references have been maintained. No opinion on nor endorsement of these works is intended or implied.

This report is divided into chapters, each of which contains a separate section of references so that each identified focus area can be explored further:

- Greenhouse gas (GHG) emissions and climate change (Chapter 2)
- Air quality (Chapter 3)
- Water use and quality (Chapter 4)
- Induced seismicity (Chapter 5)
- Land use and development (Chapter 6)
- Societal considerations for natural gas development (Chapter 7)

This report begins with the presentation of background information on domestic natural gas production and federal and state regulatory processes related to managing environmental impacts.

1.1 Natural Gas Basics

Natural gas is an odorless, gaseous mixture of hydrocarbons, largely made up of methane (CH_4) but also containing small amounts of natural gas liquids (NGLs) and nonhydrocarbon gases (e.g., carbon dioxide [CO_2] and water vapor) (Energy Information Administration [EIA], 2023b). Natural gas is one of the major combustion fuels used throughout the country. It is mainly used to generate industrial and utility electric power, produce industrial process steam and heat, and heat residential and commercial spaces. The average gross heating value of natural gas is approximately 1,031 British thermal units per standard cubic foot (Btu/scf), typically varying from 950 to 1,050 Btu/scf.[d]

Natural gas is typically classified as being either conventional or unconventional, depending on the permeability of the formation (reservoir) within which it is found, the production technology used to secure it, the current economic environment, and the scale, frequency, and duration of production from the reservoir (EIA, 2023b; Krieg, 2018). Generally, conventional natural gas refers to natural gas found in highly permeable reservoirs, typically composed of

[d] The 1,031 Btu/scf average, also equivalent to 54.1 megajoule (MJ)/kilogram (kg), is calculated using the high heating value of natural gas at standard conditions of 60 °F and 1 atm.

sandstone or limestone, which allows for extraction to be completed in a relatively straightforward manner via the use of vertical rather than horizontal drilling. Unconventional natural gas refers to natural gas found within low-permeability reservoirs, generally trapped within the pores (i.e., small, unconnected spaces) of rocks, which makes extraction more difficult and necessitates the use of advanced drilling (e.g., directional, or horizontal drilling) and well stimulation (e.g., hydraulic fracturing) techniques that can be energy intensive (British Petroleum [BP], 2017).

Unconventional natural gas production has not only made up for declining conventional natural gas production but has also led to new levels of natural gas supply in the United States. This increased supply has contributed to an increase in the use of natural gas for power generation, manufacturing, transportation, and residential and commercial heating, as well as the availability of natural gas for export from the United States.

There are three primary types of unconventional natural gas:[e]

- **Shale Gas:** refers to natural gas found within shale rock formations, which consist of fine-grained sedimentary rock that forms when silt and clay-size mineral particles are compacted together (Zendehboudi and Bahadori, 2016). Shale rock formations can be easily broken into thinner, parallel layers of rock.
- **CBM:** refers to natural gas that is both generated and stored in coal beds. Originally extracted from coal mines to reduce the potential for explosions caused by an excess of CH_4 gas within the mine and subsequently disposed of, CBM now serves as an important source of energy. Producing CBM from deeper, denser coal formations often requires the use of hydraulic fracturing technology.
- **Tight Sands Gas:** refers to natural gas found in low-permeability, gas-bearing, fine-grained sandstones, or carbonates.

Today, the majority the natural gas produced domestically is unconventional and is found in shale rock formations. These formations are often referred to as "plays" and can be found in nearly 30 U.S. states. Operators in the Barnett Shale formation, which is located in Texas and is one of the largest onshore natural gas plays in the United States, have been producing unconventional natural gas since the early 2000s (Railroad Commission of Texas [RRC], 2023).

While operators in the Barnett Shale formation still produce a significant amount of the nation's unconventional natural gas, the Marcellus Shale formation—located in the Appalachian Region of the United States and spanning areas in Ohio, Pennsylvania, and West Virginia—is currently the largest source of domestic unconventional natural gas from shale rock (EIA, 2023b).

Primary enabling technologies for accessing unconventional natural gas include hydraulic fracturing and horizontal drilling. Hydraulic fracturing (sometimes referred to as hydrofracking

[e] There are other types of unconventional natural gas whose exploitation has not yet reached commercial scale. These include methane hydrate, which is a crystalline solid that consists of a CH_4 molecule surrounded by a cage of interlocking water molecules. Methane hydrate is an "ice" that only occurs naturally in subsurface deposits where temperature and pressure conditions are favorable for its formation.

or simply fracking) is the process of pumping water mixed with a small amount of sand and other chemical additives (i.e., fracturing fluid) underground through a wellbore at a pressure that is sufficient to cause a target rock formation to break (i.e., fracture) (U.S. Geological Survey [USGS], 2019).[f,g] As the rock is fractured, natural gas that would have otherwise remained trapped is able to be released into a wellbore and returned to the surface (USGS, 2019).

The internal pressure caused by the fracturing of the rock formation also releases fluid, which travels to the surface through the wellbore. This fluid is commonly referred to as "flowback" or "produced water" and may contain the injected chemicals in addition to any naturally occurring materials found below the surface (e.g., brines, metals, radionuclides, and hydrocarbons). The fluid is oftentimes stored on site at the well-pad in tanks or pits before it is treated and disposed of or recycled. In many cases, disposing of the fluid involves injecting it underground. In areas where underground injection is not an option, the fluid can either be reused or processed by a wastewater treatment facility and subsequently discharged into surface water.

Hydraulic fracturing has been applied since the late 1940s when Standard Oil of Indiana (later known as Amoco) developed the technique and performed some of the first fracture treatments in the Hugoton Gas Field in Kansas (BP, 2017). While the use of hydraulic fracturing is not limited to wells that are horizontally drilled, the combination of horizontal drilling and hydraulic fracturing has increased the volume of domestic natural gas considered to be "technically recoverable" (i.e., able to be produced using currently available technology and industry practices regardless of any economic considerations).

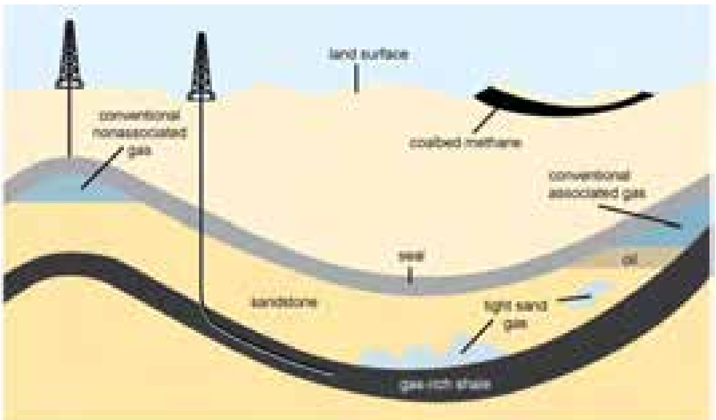
The process of horizontal drilling involves first drilling a vertical well. Once a specified depth has been reached with the vertical well, the path of drilling is bent until the well begins to extend horizontally. Horizontal wells are not only longer than vertical wells, but the process is much more complex. A horizontal well is, therefore, generally more expensive to drill than a vertical well, but it is expected to produce more natural gas (EIA, 2018). The horizontal section of a well, sometimes referred to as the directionally drilled section, can extend thousands of feet (ft).

Exhibit 1-1 provides a schematic of conventional natural gas and the various types of unconventional natural gas resources described previously (EIA, 2023b). Exhibit 1-2 provides a schematic of the combined processes of horizontal drilling and hydraulic fracturing (BP, 2017).

[f] The specific types of chemical additives used, and the proportions of each, depend on the type of rock formation that is being fractured. Additives function as friction reducers, biocides, oxygen (O_2) scavengers, stabilizers, and acids, all of which are necessary to optimize production. The composition of these fluids and the purposes of the additives are described in more detail in Chapter 4 – Water Use and Quality.

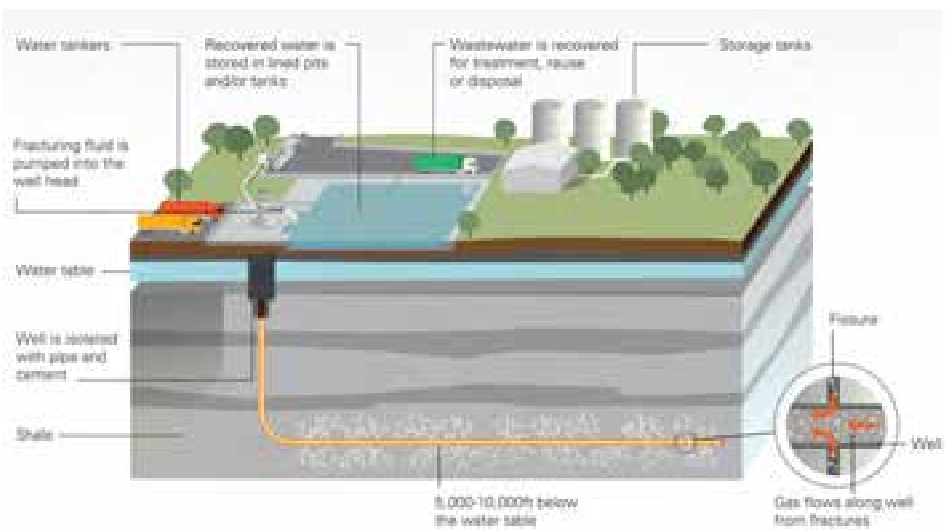
[g] In addition to enabling recovery of natural gas from unconventional resources, hydraulic fracturing techniques have also been used to produce shale oil and both natural gas and oil from conventional resources (NPC, 2011).

Exhibit 1-1. Schematic geology of natural gas resources



Source: EIA (2023b)

Exhibit 1-2. Schematic geology of natural gas resources (3D)



Permission pending from BP (2017)

1.1.1 Liquefied Natural Gas

Liquefied natural gas is natural gas that has been cooled to a liquid state (approximately -260° F or -162° C). The volume of natural gas in a liquid state is about 600 times smaller than in a gaseous state (Molnar, 2022). Liquefying natural gas is one way to allow markets that are far away from production regions, or where pipeline capacity and delivery is constrained or unavailable (e.g., New England) to access natural gas. Once in liquid form, natural gas can be shipped to terminals around the world via ocean tankers. At these terminals, the liquefied natural gas (LNG) is returned to its gaseous state and transported by pipeline to distribution companies, industrial consumers, and power plants. In some cases (over shorter distances), LNG can also be shipped by transport trailers (i.e., trucks), often to end-use facilities, where it is regasified (DOE, 2021). Liquification of natural gas not only allows for a more flexible way of transporting natural gas, but also makes it more economic to transport natural gas on a per-unit basis but only if there is a need to move the natural gas over a long distance (e.g., export natural gas to overseas markets) (Molnar, 2022). Transportation typically accounts for more than half of the total costs that occur throughout the natural gas supply chain regardless of the state of the natural gas. Both pipeline and LNG transportation systems require large upfront investment costs.[h]

1.2 U.S. Natural Gas Resources

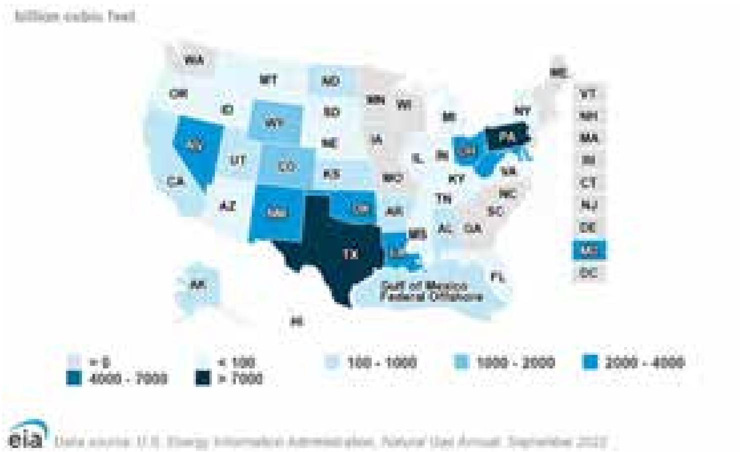
Annual U.S. production of dry natural gas was approximately 35.81 trillion cubic feet (Tcf) in 2022 (an average of about 98.11 billion cubic feet [Bcf] per day). Between 2021 and 2022, annual production of dry natural gas increased by about 4 percent from approximately 34.52 Tcf (an average of about 94.57 Bcf per day). With the exception of 2015–2016 and 2019–2020, annual domestic production of dry natural gas has increased year-over-year since 2005 as hydraulic fracturing combined with horizontal drilling has continued.

About 70 percent of the domestic dry natural gas production in 2021 was supplied by five of the United States' 34 natural gas-producing states.[i] States with a larger percentage share of total U.S. dry natural gas production in 2021 include Texas (24.6 percent), Pennsylvania (21.8 percent), Louisiana (9.9 percent), West Virginia (7.4 percent), and Oklahoma (6.7 percent) (Exhibit 1-3) (EIA, 2023b).

[h] LNG becomes cost-competitive with pipeline transportation once the distance the natural gas needs to travel exceeds 1,000 kilometers (km).

[i] 2022 state-level data was not available at the time this report was written. As such, 2021 state-level data is used above.

Exhibit 1-3. U.S. natural gas production by state in 2021

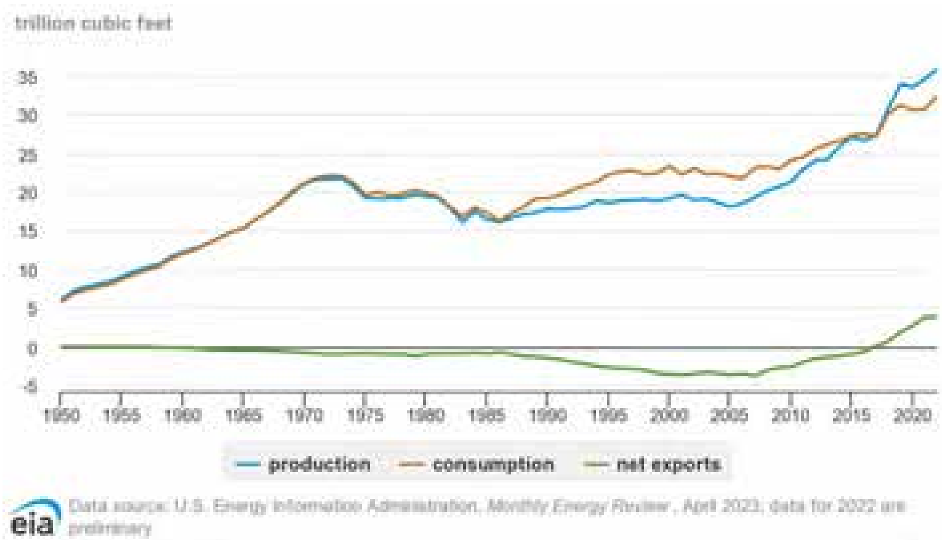


Source: EIA (2023b)

In 2022, tight sands natural gas and natural gas from shale collectively accounted for 31.62 Tcf of dry natural gas produced onshore in the lower-48 states. In the same year, 3.43 Tcf of the dry-natural gas produced on-shore was supplied by CBM (EIA, 2023b). Although most of the natural gas wells operated by the United States are located onshore, some wells are drilled offshore (i.e., into the ocean floor in waters off the coast of the United States). In 2022, offshore dry natural gas production was approximately equal to 0.80 Tcf, accounting for about 2.3 percent of total production. The majority—87.6 percent—of this production occurred in federally managed waters within the Gulf of Mexico (EIA, 2023b).

In addition to being a producer of natural gas, the United States is also a consumer and net exporter of natural gas. In 2022, the United States produced about 10.8 percent more natural gas than it consumed—on a net basis, the United States was a net exporter of natural gas. Exhibit 1-4 highlights recent (2022) and historical (1950–2021) U.S. natural gas production, consumption, and net exports (EIA, 2023a).

Exhibit 1-4. U.S. natural gas consumption, dry production, and net exports (1950–2022)



Source: EIA (2023a)

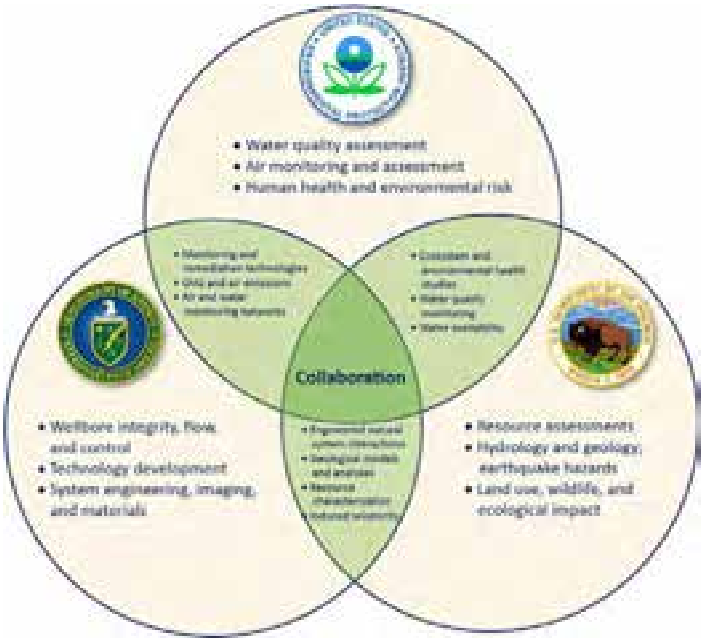
1.3 U.S. Regulatory Framework

The following sub-sections provide a review of both federal and state regulatory responsibilities related to the production, transportation, use, and export of domestic natural gas resources.

1.3.1 Federal

Multiple federal agencies have authority over the production of natural gas resources. Three of these agencies—DOE, the Department of the Interior (DOI), and the Environmental Protection Agency (EPA)—play a uniquely critical role as they are charged with monitoring, assessing, and reporting on various natural gas environmental impacts, such as those described in this report. Exhibit 1-5 describes the roles and responsibilities of these three agencies at a high-level in addition to the way they work together to inform policy-relevant science.

Exhibit 1-5. Key U.S. agencies and their roles in natural gas development and production



Source: DOE

The following subsections detail some of the specific roles and responsibilities of these agencies and, where applicable, their specific bureaus and offices. Exhibit 1-6 provides examples of the federal statutes applicable to unconventional natural gas development helping to guide the roles and responsibilities described.

Exhibit 1-6. Selected federal regulations that apply to unconventional oil and gas development

Statutes	Applicability
Clean Air Act (CAA)	Places requirements on air emissions from sources of emissions at well sites; addresses compliance with existing and new air regulations, often delegated to local and state agencies. Generally, there is no distinction made between conventional and unconventional wells under the CAA.
Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA)	Only applies if hazardous substances besides crude oil or natural gas are released in quantities that require reporting. Natural gas releases do not require notification under the Comprehensive Environmental Response, Compensation, and Liability Act, but other hazardous substances may be released in reportable quantities during natural gas production.
Clean Water Act (CWA)	Limits pollutants on produced water discharge under the National Pollutant Discharge Elimination System; stormwater runoff containing sediment that would cause a water-quality violation requires a permit under CWA decisions. Beneficial uses of surface waters are protected under Section 303.
Emergency Planning and Community Right-to-Know Act (EPCRA)	Requires facilities storing hazardous chemicals above the threshold to report same and provide a Material Safety Data Sheet to officials and fire departments.
Endangered Species Act (ESA)	Prohibits federal agencies from taking any action that is likely to jeopardize the continued existence of any endangered or threatened species (listed species) or result in the destruction or adverse modification of such species' designated critical habitat (Section 7); prohibits the taking of a listed species (Section 9); allows the Fish and Wildlife Service and National Marine Fisheries Service to issue a permit, accompanied by an approved habitat conservation plan, that allows for the incidental, non-purposeful "take" of a listed species under their jurisdictions (Section 10).
National Environmental Policy Act (NEPA)	Requires analysis of potential environmental impacts of proposed federal actions, such as approvals for exploration and production on federal lands.
Oil Pollution Act (OPA)	Identifies spill prevention requirements, reporting obligations, and response planning (measures that will be implemented in the case of release of oil or other hazardous substances).
Resource Conservation and Recovery Act (RCRA)	Addresses non-hazardous solid wastes under Subtitle D. The Solid Waste Disposal Act exempts many wastes produced during the development of natural gas resources, including drilling fluids and produced water. EPA determined that other federal and state regulations are more effective at protecting health and the environment.
Safe Drinking Water Act (SDWA)	Prevents the injection of liquid waste into underground drinking water sources through the Underground Injection Control (UIC) program. Fluids other than diesel fuel do not require a UIC permit. The UIC program gives requirements for siting, construction, operation, closure, and financial responsibility. Forty states control their own UIC programs.

1.3.1.1 Department of Interior

The DOI is a cabinet-level agency that manages America's vast natural and cultural resources through the operations of 11 technical bureaus. Of the DOI's bureaus, the Bureau of Land

Management (BLM), the National Park Service (NPS), and the U.S. Forest Service (USFS) each have responsibilities related to the enforcement of regulations for natural gas and oil wells drilled on public lands.

1.3.1.1.1 Bureau of Land Management

The BLM manages the U.S. government's onshore subsurface mineral estate—an area of about 700 million (MM) acres—from which sales of oil, gas, and natural gas liquids accounted for approximately 11 percent of all oil and 9 percent of all natural gas produced in the United States during fiscal year 2022.[j,k] About 23 of these 700 MM acres were leased to natural gas developers by the end of that year, and about 12.4 MM of those acres were producing natural gas in economic quantities (BLM, 2023).

From regulatory perspective, the BLM is responsible for 1) ensuring the environment of public lands remains protected and unaffected by natural gas production and other related activities and 2) managing natural gas development on federally owned lands. BLM published a rule regulating natural gas fracking on public lands on March 26, 2015—this rule was rescinded on December 28, 2017 (Fitterman, 2021).

On November 30, 2022, BLM proposed new regulations to reduce the waste of natural gas from venting, flaring, and leaks during oil and gas production activities on Federal and Indian leases (BLM, 2022). Key elements of the proposed rule include the following:

- Technology Upgrades: The rule would require the use of "low-bleed" pneumatic equipment as well as vapor recovery for oil storage tanks, where economically feasible. These requirements would reduce losses of natural gas from pneumatic equipment and storage tanks on federal and Indian leases.
- Leak Detection Plans: The rule would require operators to maintain a Leak Detection and Repair program for their operations on federal and Indian leases.
- Waste Minimization Plans: Requires the development of waste minimization plans demonstrating the capacity of available pipeline infrastructure to take the anticipated associated gas production. The BLM may delay action on, or ultimately deny, a permit to drill to avoid excessive flaring of associated gas.
- Monthly Limits on Flaring: Places time and volume limits on royalty-free flaring. Importantly, this includes a monthly volume limit on royalty-free flaring due to pipeline capacity constraints—the primary cause of flaring from Federal and Indian leases.

Drilling on federal or public lands is subject to oversight by federal agencies, and sections of the ESA may require that species of plants or animals not be threatened by the permitted drill site. Mandatory plans for mitigation and reclamation may be required to ensure that impacts on wildlife and habitat will be as minimal as possible.

[j] This area is held jointly by the BLM, USFS, and other federal agencies and surface owners.

[k] October 1, 2021, through September 30, 2022.

1.3.1.1.2 U.S. Forest Service

The USFS is responsible for managing access to, and the development of, federal oil and natural gas resources on approximately one-third of the over 150 national forests and grasslands. The Federal Onshore Oil and Gas Leasing Reform Act of 1987 grants the USFS authority to decide if the lands reserved from the public's domain can be leased for oil and gas development.[l] The USFS manages oil and gas activity according to the regulations at 36 CFR 228 Subpart E (USFS, 2023a). The purpose of these specific regulations is to set forth rules and procedures through which use of the federal surface lands in connection with operations authorized by the United States mining laws shall be conducted so as to minimize adverse environmental impacts.

1.3.1.1.3 National Park Service

Natural gas production and other related activities that will or do take place within the boundaries of America's national parks are managed by the NPS. Charged with protecting park resources and visitor values, the NPS helps to manage oil and gas operations following the 9B regulations. This set of regulations governs non-federal oil and gas activities and producing a final Environmental Impact Statement (EIS) for units of the national park system where oil and gas production occurs, or is likely to occur, in the foreseeable future (NPS, 2023).

1.3.1.2 Environmental Protection Agency

EPA is charged with regulating the air emissions covered under the CAA. EPA regulates several types of emissions relevant to the natural gas supply chain, including CH_4 emissions, criteria air pollutant emissions, and water and soil pollutants. EPA's New Source Performance Standards (NSPS) under the CAA set the regulations for emissions sources from the oil and natural gas sector. Exhibit 1-7 illustrates the scope of NSPS established or proposed to-date and the way regulations have evolved in scope since 2012 (EPA, 2021).

[l] Lands reserved from the public's domain include lands that have been withdrawn or reserved for use as part of the National Forests or National Grasslands or received in exchange for the same status of land (USFS, 2023b).

Exhibit 1-7. Natural gas sources covered by EPA's proposed NSPS and emissions guidelines, by site

Location and Equipment or Process Covered	Required to or Would Be Required to Reduce Emissions under CAA Rules (if finalized as proposed)	Rules that Apply			
		2012 NSPS for VOCs (OOOO)	2016 NSPS for Methane & VOCs (OOOOa)	2021 Proposed NSPS for Methane & VOCs (OOOOb)	2021 Proposed Emissions Guidelines for Methane (OOOOc)
Oil and Natural Gas Well Sites					
Completions of hydraulically fractured wells	✔	■	■	■	
Compressors at centralized tank batteries	✔			■	■
Fugitive emissions	✔		■	■	■
Liquids unloading	✔			■	
Pneumatic controllers	✔	■	■	■	■
Pneumatic pumps	✔		■	■	■
Storage vessels	✔	■	■[2]	■	■
Sweetening units	✔	■[1]	■[1]	■[1]	■[1]
Associated gas from oil wells	✔			■	■
Natural Gas Gathering and Boosting Compressor Stations					
Compressors	✔	■	■	■	■
Fugitive emissions	✔		■	■	■
Pneumatic controllers	✔	■	■	■	■
Pneumatic pumps	✔			■	■
Storage vessels	✔	■	■[2]	■	■
Sweetening units	✔	■[1]	■[1]	■[1]	■[1]
Natural Gas Processing Segment					
Compressors	✔	■	■	■	■
Fugitive emissions	✔	■		■	■
Pneumatic controllers	✔	■	■	■	■
Pneumatic pumps	✔		■	■	■
Storage vessels	✔	■	■[2]	■	■
Sweetening units	✔	■[1]	■[1]	■[1]	■[1]
Transmission and Storage Segment					
Compressors	✔		■	■	■
Fugitive emissions	✔		■	■	■
Pneumatic controllers	✔		■	■	■
Pneumatic pumps	✔			■	■
Storage vessels	✔	■	■[2]	■	■

[1]Covered for sulfur dioxide only; [2]Covered for volatile organic compounds only

Source: EPA (2021)

Following an initial proposal in November 2021, on December 6, 2022, EPA issued a supplemental proposal to update, strengthen, and expand standards intended to significantly reduce emissions of GHG and other harmful air pollutants from the Crude Oil and Natural Gas source category (EPA, 2022a). First, EPA proposed standards for certain sources that were not previously addressed. Second, EPA proposed revisions that strengthen standards for sources of leaks, provide greater flexibility to use innovative advanced detection methods, and establish a super-emitter response program. Third, EPA proposed to modify and refine certain elements of the proposed standards in response to information submitted in public comments. Finally, EPA proposed details of the timelines and other implementation requirements that apply to states to limit CH_4 pollution from existing designated facilities in the source category under the CAA (EPA, 2022a). Evaluation of this proposed rule is still in progress.

EPA's Greenhouse Gas Reporting Program (GHGRP) requires reporting of GHG emissions data and other relevant information by large sources of emissions, including fuel and industrial gas suppliers and CO_2 injection sites (EPA, 2023). The data reported is available to businesses, stakeholders, and others interested in tracking and comparing the GHG emissions of facilities, identifying opportunities to reduce emissions, minimizing wasted energy, and saving money. The petroleum and natural gas industry is covered under Subpart W of EPA's GHGRP. Unconventional natural gas production is covered under the provisions for onshore production, natural gas processing, natural gas transmission, and LNG storage and import/export. Annual CO_2, CH_4, and nitrogen oxides (NOx) emissions must be reported separately for each of these segments.

EPA studied the relationship between hydraulic fracturing for oil and natural gas and drinking water resources (EPA, 2022b). The study includes a review of published literature, analysis of existing data, scenario evaluation and modeling, laboratory studies, and case studies. EPA released a progress report in December 2012, a final draft assessment report for peer review and comment in June 2015, and the final report in December 2016. The final EPA report concludes that hydraulic fracturing activities can impact drinking water resources under some circumstances and identifies factors that influence these impacts.

Under the SDWA, EPA is charged with developing the minimum federal requirements for injection well practices to protect the public's health and prevent the contamination of underground sources of drinking water. A core element of the SDWA UIC program is setting requirements for proper well siting, construction, and operation to minimize risks to underground sources of drinking water. The Energy Policy Act of 2005 excluded hydraulic fracturing (except when diesel fuels are used) for oil, natural gas, or geothermal production from regulation under the UIC program. This statutory language caused regulators and the regulated community alike to raise questions about the applicability of permitting practices. As a result, EPA developed revised UIC Class II permitting guidance specific to oil and natural gas hydraulic fracturing activities using diesel fuels (EPA, 2022b). Although developed specifically for hydraulic fracturing where diesel fuels are used, many of the guidance's recommended practices are consistent with best practices for hydraulic fracturing in general, including those found in state regulations and model guidelines for hydraulic fracturing developed by industry and stakeholders. Thus, states and tribes responsible for issuing permits and/or updating regulations for hydraulic fracturing will find the recommendations useful in improving the protection of underground sources of drinking water and public health in general wherever hydraulic fracturing occurs. The guidance outlines for EPA permit writers, where they are the permitting authority, 1) existing Class II requirements for diesel fuels used for hydraulic fracturing of wells, and 2) technical recommendations for permitting those wells consistently with these requirements (EPA, 2022b).

EPA completed a stakeholder engagement effort in 2019 that sought input on how the agency, states, tribes, and stakeholders regulate and manage wastewater from the oil and gas industry. EPA released a draft report in May 2019 that described what it heard during its engagement for this study (EPA, 2022b). EPA accepted public input on the draft report and, after considering this input, published a final report in May 2020 (EPA, 2020). In many regions of the United States, underground injection is the most common method of managing fluids or other substances from shale gas extraction operations. Management of flowback and produced water via underground injection is regulated under the SDWA UIC program. The CWA effluent guidelines program sets national standards for industrial wastewater discharge to surface waters and municipal sewage treatment plants based on the performance of treatment and control technologies. Effluent guidelines for onshore oil and natural gas extraction facilities prohibit the discharge of pollutants into surface waters, although some permit exceptions may allow for discharge under unique conditions. On June 28, 2016, EPA promulgated pretreatment standards for the Oil and Gas Extraction Category (40 CFR Part 435). These regulations prohibit discharge of wastewater pollutants from onshore unconventional oil and natural gas extraction facilities to publicly owned treatment works (POTWs).[m]

1.3.1.3 Department of Energy

The Natural Gas Act (NGA) requires DOE to make public interest determinations on applications to export LNG to countries where the United States does not have existing free trade agreements requiring national treatment for trade in natural gas. The Office of Fossil Energy and Carbon Management's (FECM) natural gas import–export regulatory program is implemented by the Division of Regulation in the Office of Regulation, Analysis, and Engagement. Typically, the Federal Energy Regulatory Commission (FERC) has direct regulatory responsibility over the siting, construction, and operation of onshore LNG export facilities in the United States. In these cases, FERC leads the environmental impact assessments of proposed projects consistent with NEPA, and DOE is typically a cooperating agency as part of these reviews (DOE, 2023a). Similarly, for offshore LNG export facilities, the Department of Transportation's (DOT) Maritime Administration (MARAD) is responsible for environmental reviews, in coordination with the U.S. Coast Guard, guided by requirements in the Deepwater Port Act. Again, DOE is typically a cooperating agency in these reviews. In some limited circumstances, DOE is the lead agency for NEPA reviews related to proposed LNG exports.

FECM's Point Source Carbon Capture Division's research, development, demonstration, and deployment portfolio facilitates the development of technologies and infrastructure that improve performance, reduce costs, and scale the deployment of technologies to decarbonize the industrial and power sectors and remove CO_2 from the atmosphere. Within the natural gas supply chain, these efforts include research and commercial-scale demonstration of technologies that advance carbon capture and storage on natural gas-fired power plants and industrial natural gas combustion streams (DOE, 2023a).

FECM is working to support efforts to decarbonize LNG terminals through exploration of technical and economic feasibility of carbon capture on gas separation and combustion streams and the use of electric motor drives supplied by net-zero emissions electricity. Decarbonizing LNG terminals is a key part of the effort to reduce life cycle emissions associated with the export of natural gas to global allies.

FECM's Methane Mitigation Technologies Division aims to eliminate non-trivial fugitive and vented CH_4 emissions from the natural gas supply chain to reduce the climate impacts from the production and use of natural gas. The division is focused on developing accurate, cost effective, and efficient technology solutions and best practices to identify, measure, monitor, and minimize CH_4 emissions from these sources. DOE funded several technology investigations through NETL that deal with produced water management and life cycle assessments of the natural gas value chain (DOE, 2023b). NETL's Natural Gas Infrastructure Field Work Proposal aims to strengthen natural gas pipeline reliability and reduce emissions on two fronts: quantifying GHG emissions and developing material and sensor technologies that will help to

[m] "Publicly owned treatment works" is a term used in the United States to designate a sewage treatment plant owned, and usually operated, by a government agency. In the United States, POTWs are typically owned by local government agencies and are usually designed to treat domestic sewage and not industrial wastewater.

mitigate these emissions. Research in this Field Work Proposal will also help address the reliability, public safety, operational efficiency, and flexibility of the America's aging natural gas infrastructure.

On April 21, 2023, a Request for Information (RFI) was issued by FECM to obtain input to inform DOE's research and development (R&D) activities within the Office of Research and Development's Methane Mitigation Technologies Division and the Office of Carbon Management Technologies' Point Source Carbon Capture Division. In addition, such data and information could help inform the Office of Regulation, Analysis, and Engagement's capabilities to assess natural gas import and/or export applications. Through the RFI, DOE requested information on strategies and technologies that natural gas and LNG companies are deploying, or could deploy, to reduce GHG emissions and other air pollutants associated with natural gas delivered to liquefaction facilities, housed at liquefaction facilities, and being loaded, transported, and delivered to regasification facilities (DOE, 2023a).

1.3.1.4 Occupational Safety and Health

The Occupational Safety and Health Administration (OSHA) establishes standards, directives (instruction to OSHA staff), letters of interpretation, and national consensus standards that pertain to employee safety within the oil and gas extraction industry (OSHA, 2023). OSHA standards are in place to limit employee exposures to hazards present during oil and gas well drilling, servicing, and storage. Regulations and standards related to site preparation activities, which include leveling the site, trenching, and excavation, are covered under 29 CFR 1926, while all other aspects drilling and servicing operations are covered by 29 CFR 1910 (OSHA, 2023).

1.3.1.5 Pipeline and Hazardous Materials Safety Administration

DOT's Pipeline and Hazardous Materials Safety Administration (PHMSA) Office of Pipeline Safety is responsible for carrying out a national program to ensure the safe, reliable, and environmentally-sound operation of the nation's natural gas and hazardous liquid pipeline transportation system. PHMSA develops, proposes, and implements regulatory policy initiatives and regulations governing the pipeline. The office also directs education and outreach efforts to promote the adoption and increased use of safety programs and activities by state and local governments, pipeline operators, and the general public in their efforts to enhance safety (DOT, 2018).

1.3.2 States

States have the power to implement their own requirements and regulations for natural gas drilling that are equivalent to or more stringent than established federal practices.[n] All states that produce natural gas have at least one agency charged with issuing new permits for production wells. While state requirements for permits can differ, any requirements set forth by federal regulations must be met for a state-level permit to be issued. Beyond issuing new

[n] Zirogiannis et al. (2016) developed a framework for comparing states based on how intensely they regulate unconventional gas development.

permits for production, states can also issue regulatory requirements for managing the potential environmental impacts of natural gas activities.

Although regulations, rules, and restrictions vary by state, in some cases, the actions taken by one or a subset of states have helped to both inform similar regulations imposed by other states and further refine some federal rules. A number of states, including Colorado, New Mexico, and Pennsylvania have adopted regulations to help manage GHG emissions including CH_4 and other air pollutants (e.g., volatile organic compounds) from oil and natural gas operations (Commonwealth of Pennsylvania, 2023b). Colorado, in particular, is in the process of developing a rule focused on verifying GHG emissions intensity reporting (Colorado Department of Public Health & Environment, 2023).

In Oklahoma, using existing regulatory authorities, state regulators are expanding their technical guidance to inform operator efforts to sustainably manage produced water while reducing incidences of induced seismicity. For example, Oklahoma authorities have systemically identified areas of seismic concern and are 1) focusing resources where induced seismicity has previously occurred due to underground fluid injection activities, and 2) implementing new protocols for hydraulic fracturing, well completion, and wastewater disposal underground (Skinner, 2018). As for land use and development considerations, there are permissible noise levels embodied in regulations that gas operators across Colorado must adhere to. For example, drilling, well stimulation and completion, as well as workovers, are now held to maximum permissible noise level standards for industrial zones.

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2 Greenhouse Gas Emissions

The primary GHG emissions associated with the natural gas supply chain steps of production through transport are emissions of CO_2 and CH_4. CO_2 emissions are primarily the result of fossil fuel combustion, which is done to power equipment and operations. CH_4 emissions are the result of intentional and unintentional releases of natural gas as it moves through the supply chain. CH_4 is the primary component of natural gas. CO_2 and CH_4 emissions vary significantly across different regions and supply chains depending on the composition of the natural gas that is being produced, the type of equipment being used to process and transport the natural gas, and the number and size of intentional and unintentional releases of the natural gas.

2.1 Overview of GHG Emissions

The U.S. natural gas system encompasses hundreds of thousands of wells, hundreds of processing facilities, and over 1 MM miles of transmission and distribution pipelines. EPA develops an annual report—"Inventory of U.S. Greenhouse Gas Emissions and Sinks" (hereafter, the GHGI)—that tracks domestic GHG emissions and sinks by source and economic sector going back to 1990 (EPA, 2023a). The GHGI was last released in April 2023 and provided annual estimates up to the year 2021 (EPA, 2023a). Contained within the GHGI are annual estimates of the GHG emissions including CH_4, associated with natural gas systems.

EPA's April 2023 release of the GHGI estimated that total GHG emissions (including CH_4, CO_2, and nitrous oxide [N_2O]) from natural gas systems in 2021 were 217.5 MM metric tons (MMT) of carbon dioxide equivalent (CO_2e), a decrease of 12 percent from 1990 and a decrease of 2 percent from 2020, both primarily due to decreases in CH_4 emissions. From 2010, emissions decreased by 3 percent, primarily due to decreases in estimated CH_4 emissions. Of the overall GHG emissions from natural gas systems (217.5 MMT CO_2e), 83 percent are CH_4 emissions (181.4 MMT CO_2e), 17 percent are CO_2 emissions (36.2 MMT CO_2e), and less than 0.01 percent are N_2O emissions (0.01 MMT CO_2e). Note that the GHGI reports emissions from engines and turbines used to power natural gas operations as part of its fossil fuel combustion estimate; those emissions are not included in these estimates. Exhibit 2-1 shows estimates of one GHG emission—CH_4—by segment of the natural gas system (exploration through distribution) as reported by the GHGI.

Exhibit 2-1. EPA GHGI CH_4 emissions from natural gas systems (kiloton)

Segment	1990	2005	2017	2018	2019	2020	2021
Exploration	119	358	49	94	75	9	7
Production	2,311	3,495	3,697	3,823	3,739	3,475	3,360
Onshore Production	1,403	2,464	2,139	2,246	2,122	1,923	1,787
Gathering and Boosting	739	958	1,533	1,547	1,591	1,520	1,548
Offshore Production	170	73	26	30	25	32	24
Processing	853	463	460	483	506	495	510
Transmission and Storage	2,288	1,580	1,460	1,538	1,583	1,625	1,590
Distribution	1,819	1,018	561	557	554	553	548
Post-Meter	290	344	424	445	457	463	463
Total	**7,680**	**7,260**	**6,652**	**6,939**	**6,914**	**6,619**	**6,478**

Note: To enable results comparison across exhibits, it is important to note the following conversion: 1,000 kiloton of CH_4 is equal to 1 Tg of CH_4.

The global warming potential (GWP) metric was developed to allow comparisons of the global warming impacts of different GHG emissions (e.g., CH_4, CO_2, and N_2O). Specifically, it is a measure of how much energy the emissions of 1 ton of a specific GHG will absorb over a given period, relative to the emissions of 1 ton of CO_2. The larger the GWP, the more that a given gas warms the Earth compared to CO_2 over that period. The period usually used for GWPs is 100 years. GWPs provide a common unit of measure, which allows analysts to add up emissions estimates of different gases (e.g., to compile a national GHG inventory), and allows policymakers to compare emissions reduction opportunities across sectors and gases (EPA, 2023b):

- CO_2, by definition, has a GWP of 1 regardless of the period used, because it is the gas being used as the reference. CO_2 remains in the climate system for a very long time: CO_2 emissions cause increases in atmospheric concentrations of CO_2 that will last thousands of years.
- CH_4 is estimated to have a GWP of 27–30 over 100 years. CH_4 emitted today lasts about a decade on average, which is much less time than CO_2. But CH_4 also absorbs much more energy than CO_2. The net effect of the shorter lifetime and higher energy absorption is reflected in the GWP. The CH_4 GWP also accounts for some indirect effects, such as the fact that CH_4 is a precursor to ozone, and ozone is itself a GHG.
- N_2O has a GWP 273 times that of CO_2 for a 100-year timescale. N_2O emitted today remains in the atmosphere for more than 100 years, on average.
- Chlorofluorocarbons, hydrofluorocarbons, hydrochlorofluorocarbons, perfluorocarbons, and sulfur hexafluoride are sometimes called high-GWP gases because, for a given amount of mass, they trap substantially more heat than CO_2. (The GWPs for these gases can be in the thousands or tens of thousands.)

Based on a review of the science of climate change, the Intergovernmental Panel on Climate Change (IPCC) estimated the GWP for CH_4 to be 36 over a 100-year period and 87 over a 20-year period in their Fifth Assessment Report (AR5) published in 2014 (IPCC, 2014). In the IPCC's Sixth Assessment Report (published in 2021), the IPCC revised the GWP estimates of CH_4 to be 29.8 over a 100-year horizon and 82.5 over a 20-year time horizon (IPCC, 2021). It is important to consider which GWP is used when reviewing the outputs of an analysis of GHG emissions, particularly when comparing the outputs of two or more analyses.

2.2 Sources of GHG Emissions

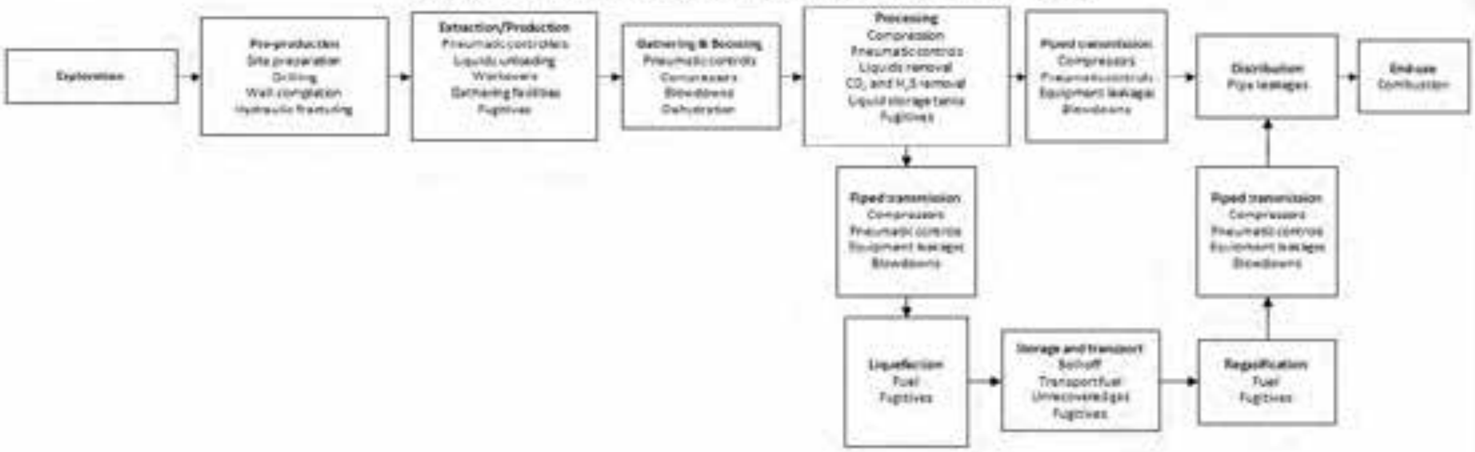
To account for all sources of GHG emissions in the natural gas supply chain, and to evaluate their relative contributions and mitigation opportunities, a systems-level perspective is both necessary and preferred. Life cycle analysis (LCA) is one type of systems-level approach available to account for the different sources of GHG emissions in the natural gas supply chain. LCA specifically considers the material and energy flows of an entire system "from cradle to grave"—where "cradle" refers to the extraction of resources from the earth, and "grave" refers to the final use and disposition of all products. The two relevant standards for LCA are International Organization for Standardization (ISO) 14040 and ISO 14044. ISO 14040 describes the principles and framework for LCA, and ISO 14044 specifies requirements and provides guidelines for LCA.

Depending on the type of LCA conducted, different system boundaries can be put in place to more accurately estimate the GHG emissions associated with natural gas. Generally, GHG emissions occur from the beginning of the natural gas supply chain (during exploration) through the end (during utilization). In some cases, an LCA may not be able to consider every step of the natural gas supply chain within its analysis framework. This can happen for a variety of reasons, including lack of emissions data for a particular step or set of steps, or to focus specifically on the emissions associated with one particular step. Exhibit 2-2 provides an illustration of the natural gas supply chain with examples of key emissions sources.

NETL has used LCA to calculate the environmental impacts of natural gas production and use for the generation of electric power for nearly a decade (NETL, 2023). NETL's work has been documented in a series of reports produced between 2010 and 2019, which together provide in-depth assessments of the potential GHG emissions resulting from upstream unconventional natural gas production in the United States (NETL, 2019a). [o] In addition to characterizing domestic upstream natural gas, NETL also developed life cycle data for exported LNG, including the GHG emissions from liquefaction, loading/unloading, ocean transport, regasification, and combustion for electricity generation (NETL, 2019b).

[o] The GHG results in the NETL (2019a) report supersede the GHG results in the previous NETL reports.

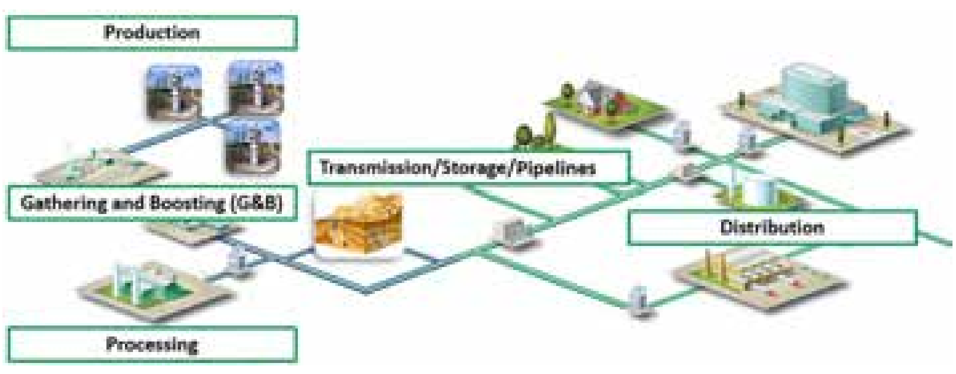
Exhibit 2-2. Natural gas supply chain with examples of key emissions sources



The GHG emissions results reported in past NETL natural gas LCAs consider five stages of the natural gas supply chain, which are visualized in Exhibit 2-3 (NETL, 2019a):

1. **Production:** Sources of emissions include the gas vented from pneumatically controlled devices and fugitive emissions from flanges, connectors, open-ended lines, and valves. When vapor recovery units are feasible, vented gas is captured and flared; otherwise, vented gas is released to the atmosphere. Production operations also include the combustion of natural gas and diesel in compressors and other equipment.
2. **Gathering and Boosting (G&B):** Natural gas G&B networks receive natural gas from multiple wells and transport it to multiple facilities. G&B sites include acid gas removal, dehydration, compressors operations, pneumatic devices, and pumps.
3. **Processing:** A natural gas processing facility removes impurities from natural gas, which improves its heating value and prepares it for pipeline transmission. Natural gas processing facilities include acid gas removal, dehydration, hydrocarbon liquids removal, and compression operations.
4. **Transmission Stations, Storage Facilities, and Transmission Pipelines:** A natural gas transmission system is a network of large pipelines that transport natural gas from processing facilities to the city gate (the point at which natural gas can be consumed by large-scale consumers or transferred to local distribution companies). Transmission stations are located along natural gas transmission pipelines and use compressors to boost the pressure of the natural gas. Large industrial users typically access natural gas directly from transmission pipelines.
5. **Distribution:** Natural gas distribution networks transport natural gas from the city gate to commercial, residential, and some industrial consumers. This analysis uses the distribution portion of the supply chain only for the upstream functional unit; distribution is not necessary for the functional unit of electricity in which natural gas power plants receive natural gas directly from transmission pipelines.

Exhibit 2-3. Supply chain stages that compose the overall LCA boundary



The flexible, consistent framework of NETL's LCA model allows different natural gas sources to be compared on a common basis (per MJ of delivered natural gas). In the NETL (2019a) report, five types of natural gas are considered:

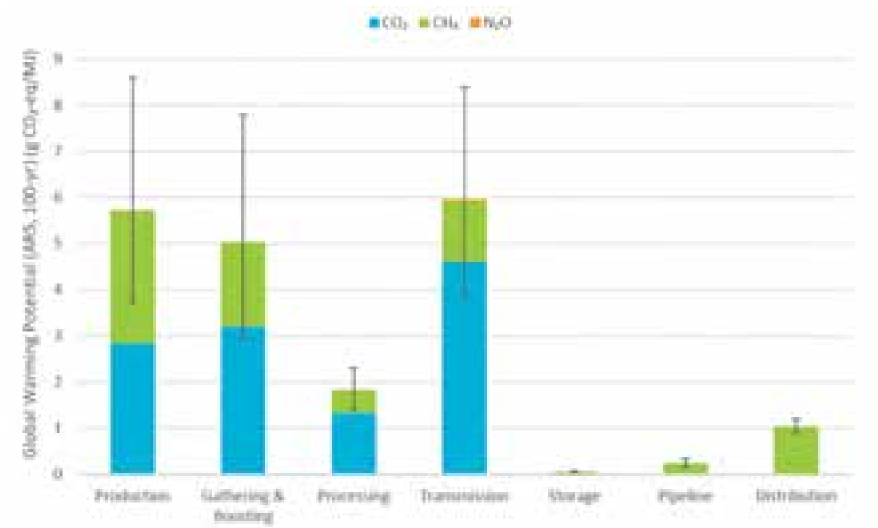
1. **Conventional natural gas** is natural gas extracted via vertical wells in high permeability formations that generally do not require, but can in some cases benefit from, stimulation technologies (e.g., hydraulic fracturing) for primary production.
2. **CBM** is extracted from coal seams and requires the removal of naturally occurring water from the seam before natural gas wells are productive.
3. **Shale gas** is extracted from low permeability formations and requires hydraulic fracturing and horizontal drilling.
4. **Tight gas** is extracted from non-shale, low permeability formations and requires hydraulic fracturing and directional drilling.
5. **Associated gas** is found with petroleum (either dissolved in oil or in a gas cap in a petroleum formation) and is produced by oil wells.

In the 2019 LCA analysis of the natural gas supply chain, NETL used the GWP reported in the IPCC AR5 (NETL, 2019a). Results from the 2019 NETL LCA analysis performed suggested the following (NETL, 2019a):

- The life cycle GHG emissions associated with the U.S. natural gas supply chain were 19.9 grams (g) of CO_2e per MJ of natural gas delivered (with a 95 percent mean confidence interval of 13.1–28.7 g CO_2e per MJ). The boundary used in this study was natural gas production through transmission to large end-users.
- The top contributors to CO_2 and CH_4 emissions were combustion exhaust and other venting from compressor systems. Compressor systems are prevalent in most stages of the natural gas supply chain and as such were key contributors to the total life cycle emissions estimated.
- Emissions rates are highly variable across the entire supply chain. According to the study, the national average CH_4 emissions rate was 1.24 percent, with a 95 percent mean confidence interval ranging 0.84–1.76 percent.

Exhibit 2-4 shows the GHG emissions from the different parts of the natural gas supply chain (NETL, 2019a).

Exhibit 2-4. Life cycle GHG emissions for the U.S. natural gas supply chain



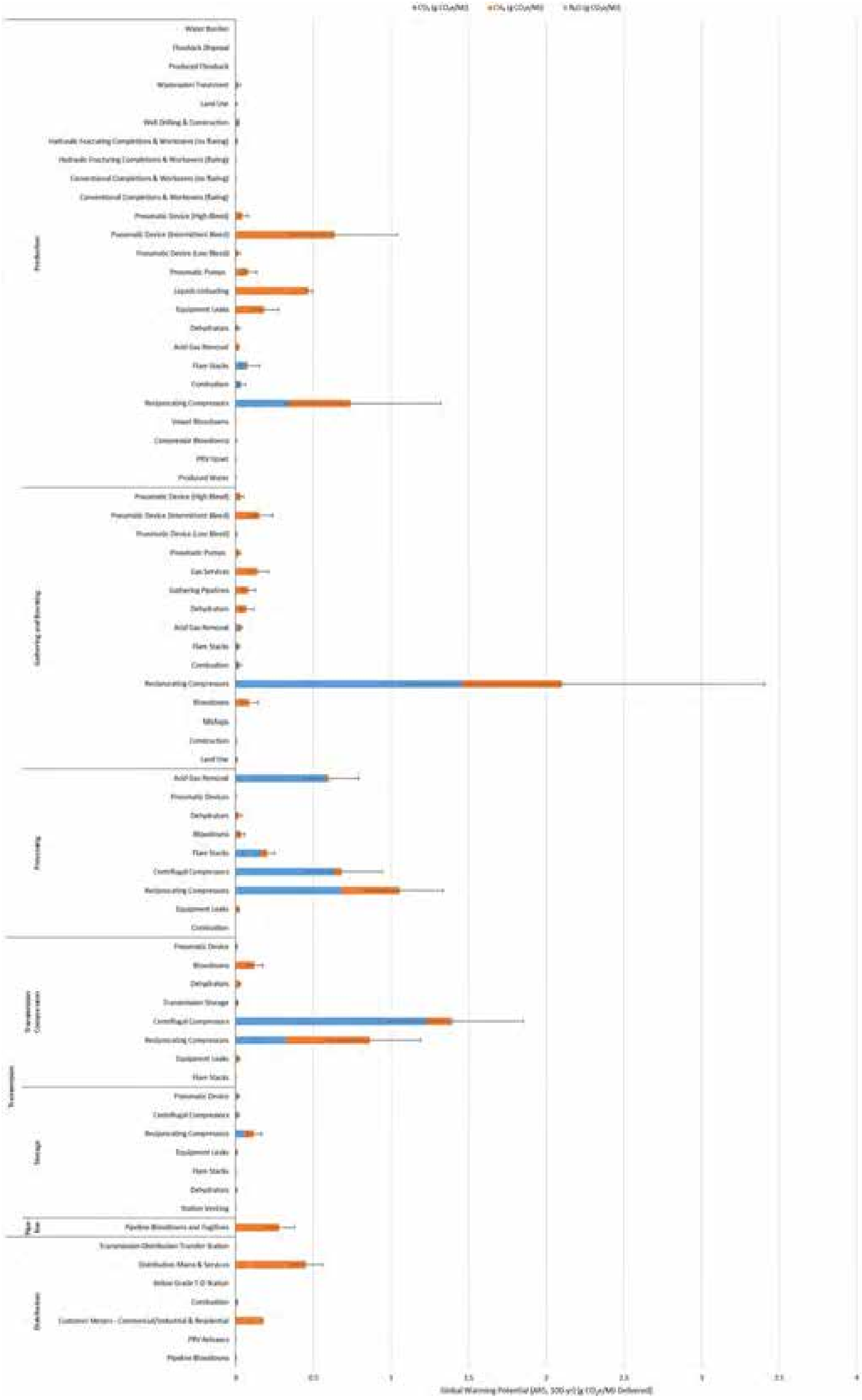
Key drivers of GHG emissions results for the entire U.S. gas supply chain in 2017 are illustrated in Exhibit 2-5 (Littlefield et al., 2020). Pneumatic devices and compression systems represent a significant portion of the total life cycle GHG emissions associated with the natural gas supply chain (NETL, 2019a).

Pneumatic devices are used to operate level controllers, valves, and other equipment at natural gas facilities. According to EPA's GHGI, pneumatics in the production segment emitted 1,060 kilotons of CH_4 in 2017, accounting for 16 percent of the total CH_4 emissions from the natural gas supply chain. Pneumatic device activity is concentrated at production facilities and there were 833,000 pneumatic devices used by U.S. production facilities in 2019 (Littlefield et al., 2020).

Natural gas is compressed for transport from processing facilities to end-consumers. As such, upstream GHG emissions are sensitive to pipeline distances and the number of compressors along these pipelines that the natural gas must pass through. The energy intensity of compression and the fugitive CH_4 emissions from compressors both contribute to upstream GHG emissions (NETL, 2019a).

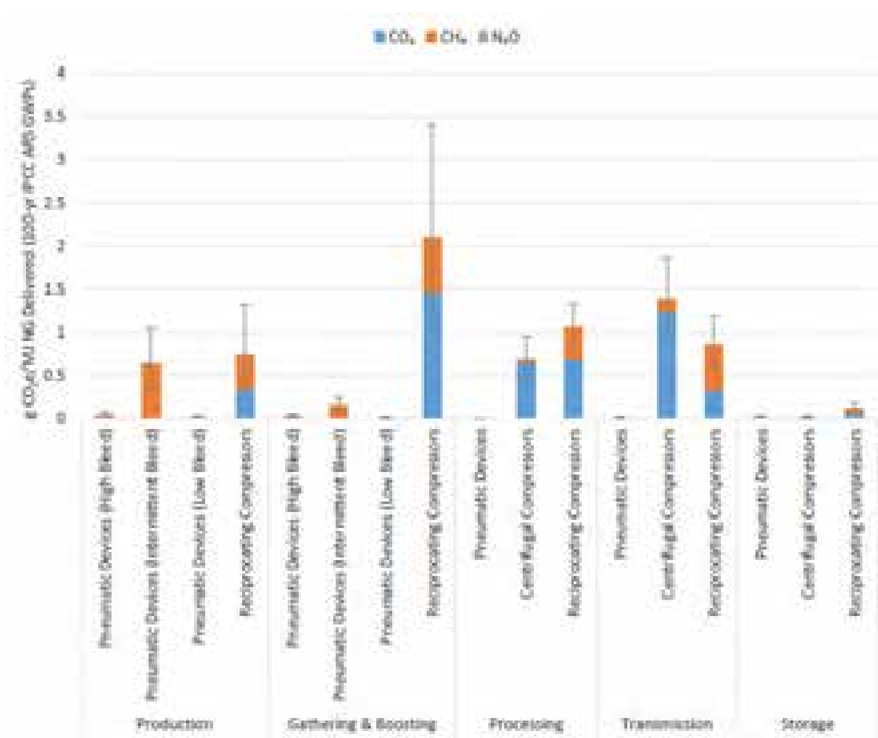
In addition to being a source of CH_4 emissions, compressors are also a source of CO_2 emissions. Most compressors in the U.S. pipeline transmission network are powered by natural gas that is withdrawn from the pipeline itself. Electric motors are not widely used by natural gas pipelines but are installed where local emissions regulations limit the use of internal combustion engines or where inexpensive electricity is available. Nationwide in 2017, 6 percent of compressor stations were powered by electricity, 77 percent were powered by natural gas, and 17 percent were dual gas and electric (Littlefield et al., 2020).

Exhibit 2-5. U.S. average for 2017—detailed GHG emissions sources for the U.S. natural gas supply chain (gCO_2e/MJ)



Two sources of CH_4 emissions from compressor systems include 1) uncombusted CH_4 that slips through the compressor exhaust stream and 2) CH_4 that escapes through compressor seals or packing. Natural gas systems use both centrifugal and reciprocating compressors. Centrifugal compressors are more appropriate for pressure boosting applications in steady-state applications (such as with a transmission pipeline), while reciprocating compressors are more appropriate when gas flow is variable and when large increases in pressure are required. Centrifugal compressors are typically driven by gas-fired turbines but, in some instances, are driven by an electric motor. Reciprocating compressors are driven by gas-fueled engines. Exhibit 2-6 illustrates the emissions associated with pneumatic devices and compressors (Littlefield et al., 2020).

Exhibit 2-6. GHG emissions from pneumatic devices and compressors across the natural gas supply chain (gCO_2e/MJ)



For all natural gas production types, the GHG emissions results produced by an LCA are sensitive to the following factors:

- Estimated ultimate recovery

- Regional natural gas composition differences (dry versus sour gas)
- Compression energy requirements and type
- Pneumatic device type, frequency, and number of devices per operation

In the same NETL (2019a) report, NETL analyzed the N_2O emissions at each stage of the natural gas supply chain. The analysis found a total of 0.14 milligrams (mg) of N_2O were emitted per MJ of natural gas delivered (Exhibit 2-7). The largest contributor (86 percent) to this total number was N_2O emissions that occur during the transmission stage.

Exhibit 2-7. N_2O emissions across the natural gas supply chain

Stage of Natural Gas Supply Chain	N_2O Emissions (mg/MJ)
Production	0.016
G&B	< 0.0001
Processing	0.0047
Transmission	0.12
Storage	< 0.0001
Pipeline	< 0.0001
Distribution	< 0.0001
Total	**0.14**

2.3 Methane Emissions Studies

There are two primary approaches used to estimate CH_4 emissions as part of an LCA: 1) top-down and 2) bottom-up (Rutherford et al., 2021; Alvarez et al., 2018; Balcombe et al., 2016). A top-down approach a) measures the atmospheric concentrations of CH_4 as reported by fixed ground monitors, mobile ground monitors, aircraft, and/or satellite monitoring platforms; b) aggregates the results to estimate total CH_4 emissions; and c) allocates a portion of these total emissions to each of the different supply chain activities. A bottom-up approach measures GHG emissions directly from each source of emissions, then aggregates and extrapolates these measurements to estimate emissions for an entire region or process. Both approaches have advantages and disadvantages.

Top-down approaches (see Rutherford et al., 2021; Alvarez et al., 2018; Balcombe et al., 2016) tend to report higher emissions from natural gas systems as compared to bottom-up approaches. There are several factors that may lead to these results, which can be generally explained as follows:

- Top-down approaches capture more emissions sources by covering an entire area. However, depending on the methodology, these approaches sometimes fail to distinguish between different sectors. For example, aircraft that are used to collect emissions data for a particular area may struggle to distinguish between the CH_4 emissions coming from a natural gas processing facility in the area from those coming from a nearby dairy farm. This can lead to incorrect contributions of total CH_4 emissions to specific natural gas activities.

- Bottom-up approaches sometimes fail to capture infrequent high emitting events such as malfunctioning or improperly operated equipment. Because bottom-up approaches measure emissions from individual sources, it can be challenging to accurately capture the contributions of infrequent events to total emissions.

Considerable recent and ongoing research has been devoted to understanding and reconciling the differences between top-down and bottom-up approaches to estimating CH_4 emissions. Example studies include the following:

- The Colorado State University (CSU) Energy Institute's Basin Methane Reconciliation Study—commissioned by NETL, through the Research Partnership to Secure Energy for America (RPSEA) program—was designed to understand, and potentially reconcile, the persistent gap between top-down and bottom-up CH_4 emissions estimates for production regions (CSU, 2018; Vaughn et al., 2018). To minimize the potential shortcomings of prior studies, the Basin Methane Reconciliation Study was designed as a first of its kind to conduct contemporaneous measurements at the device, facility, and regional scales, with site access and activity and emissions data input from local natural gas operators. The study was a multi-agency research project that drew from the scientific expertise of CSU, Colorado School of Mines, University of Colorado-Boulder, the National Oceanic and Atmospheric Administration, and the National Renewable Energy Laboratory. The University of Wyoming, AECOM, Aerodyne, and GHD Engineering also participated in the study.
- In 2019, Environmental Defense Fund launched the Permian Methane Analysis Project (PermianMAP), a first-ever, near real-time CH_4 monitoring initiative in the world's largest oil field (Environmental Defense Fund, 2021; Lyon et al., 2021). Researchers first began collecting aerial CH_4 data in late fall of 2019 and conducted more than 100 flights across the Basin throughout 2020 and 2021. Some flights encompassed the full perimeter of the 10,000 square kilometers (km^2) study area. Others zeroed in on a cluster of randomly selected wells. Carbon Mapper researchers partnered with the PermianMAP project in the summer and fall of 2021, detecting nearly 1,700 plumes over 26 flight days. Leak Surveys Inc., a veteran leak detection company, used a helicopter equipped with an infrared camera to conduct surveys of more than 3,000 flares across the entire Permian Basin to determine their contribution to the region's CH_4 emissions.

Alvarez et al. (2018) note that in many bottom-up approaches to modeling, operator cooperation is required to obtain site access for accurate emissions measurements. Operators with lower-emitting sites are plausibly more likely to cooperate with such studies and workers are plausibly more likely to be careful to avoid errors or fix problems when measurement teams are on site or about to arrive, which could lead to a downward bias in estimates of potential emissions (Rutherford et al., 2021; Alvarez et al., 2018; Balcombe et al., 2016).

Balcombe et al. (2016) document the wide range of CH_4 emissions estimates across the natural gas supply chain. Significant drivers of this wide range of projections are 1) the emissions associated with natural gas production, and 2) whether the natural gas is ultimately converted to LNG. The following sub-sections explore these different segments of the supply chain.

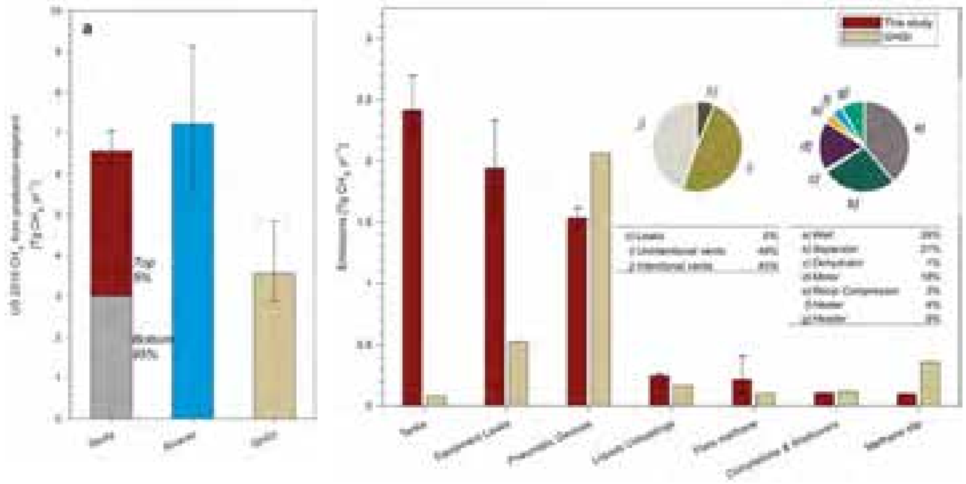
EPA estimates oil and natural gas CH_4 emissions in the annual GHGI it produces. The GHGI uses a bottom-up approach to estimate national CH_4 emissions. Several studies have found that CH_4 emissions from the natural supply chain are about 1.5–2.5 times the amount reported in EPA's GHGI (Rutherford et al., 2021; Alvarez et al., 2018; Balcombe et al., 2016). Much of the discrepancy can be attributed to differences in the analyses performed for the production segment of the natural gas supply chain where infrequent, high emissions events, or "super emitters," and emissions-intensive equipment are prevalent (Rutherford et al., 2021; Alvarez et al., 2018; Balcombe et al., 2016).

To isolate specific sources of disagreement between EPA's GHGI and other studies, Rutherford et al. (2021) reconstructed EPA's GHGI emissions factors, beginning with the underlying datasets, and identified possible sources of disagreement between inventory methods and top-down studies. The adjusted emissions factors are direct inputs in the Rutherford et al. (2021) study outputs. Rutherford et al. use a bottom-up measurement approach, yet the approach differs from the GHGI in that it applies a bootstrap resampling statistical approach to allow for inclusion of infrequent, large emitters, thereby incorporating data on super emitters in a more robust way.

Rutherford et al. (2021) estimate the mean, production-normalized emissions rate from the production segment as 1.3 percent (1.2–1.4 percent at 95 percent confidence interval, based on gross natural gas production of 32 Tcf and an average CH_4 content of 82 percent), slightly lower than Alvarez et al., 2018) who estimate it at 1.4 percent. Rutherford et al. (2021) estimate mean natural gas production-segment CH_4 emissions as equal to 6.6 teragrams (Tg) per year (6.1–7.1 Tg per year, at 95 percent confidence interval). Both the results of Rutherford et al. (2021) and Alvarez et al. (2018) are approximately two times larger than estimates of the 2015 EPA GHGI, which suggests that 3.6 Tg of emissions per year (year 2015 data, excludes offshore systems) come from the natural gas production segment.

Given that the Rutherford et al. (2021) results match Alvarez et al.'s (2018) site-level results, the former concludes that the divergence between the GHGI and top-down/site-level studies is not likely to be due to any inherent issue with the bottoms-up approach. A results comparison of the Rutherford et al. (2021) study, the Alvarez et al. (2018) study, and 2015 EPA GHGI data can be found in Exhibit 2-8.

Exhibit 2-8. Comparison of GHG emissions results from Rutherford et al., Alvarez, et al., and EPA GHGI



Note: "This study" and "Study" labels on the x-axis refer to Rutherford et al. (2021)

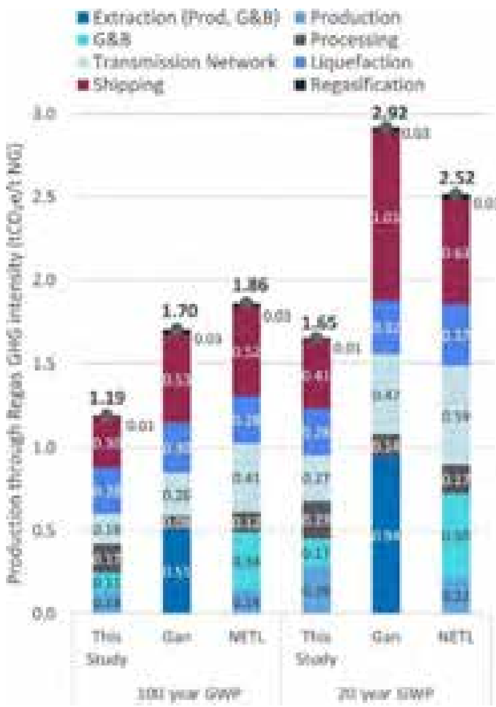
Used with permission from Rutherford et al. (2021)

Littlefield, Rai, and Skone (2022) provide a detailed life cycle perspective on GHG emissions variability where natural gas is produced and where it is delivered (via pipeline). They disaggregate transmission and distribution infrastructure into six regions, balance natural gas supply and demand locations to infer the likely pathways between production and delivery (estimated via modeling as actual tracking of natural gas from well to customer is not technically feasible), and incorporate new data on distribution meters. They find the average transmission distance for U.S. natural gas is 815 km but ranges 45–3,000 km across estimated production-to-delivery pairings examined (Littlefield, Rai, and Skone, 2022). In terms of total GHG emissions, their results suggest the delivery of 1 MJ of natural gas to the Pacific region has the highest mean life cycle GHG emissions (13.0 gCO_2e/MJ) and the delivery of natural gas to the Northeastern region of the United States has the lowest mean life cycle GHG emissions (8.1 gCO_2e/MJ).

2.3.1 LNG Studies

At the end of 2020, Cheniere Energy was the largest exporter of LNG from the United States in terms of volume. Roman-White et al. (2021) developed an LCA framework to estimate GHG emissions representative of Cheniere's LNG supply chain, considering both upstream and downstream sources of emissions from Cheniere's Sabine Pass Liquefaction facility, using supplier-specific data collected from wellhead through ocean transport. Roman-White et al. (2021) compare the GHG emissions intensity of Cheniere LNG to two similar assessments of emissions intensity from U.S. LNG transported to China (Gan et al., 2020; NETL, 2019b). The results of their comparison are illustrated in Exhibit 2-9.

Exhibit 2-9. Comparison of GHG emissions results from Roman-White et al., Gan et al., and NETL



Used with permission from Roman-White et al. (2021)

Note: "This study" labels on the x-axis refer to Roman-White et al. (2021)

The NETL (2019b) LNG study uses more recent production emissions data (2016 data) than Gan et al. (2020). The NETL (2019b) study is based on natural gas production in Appalachia with relatively low emissions intensity. The NETL analysis differs from the Roman-White et al. (2021) study primarily in the intensity of the G&B and transmission stages, which are driven by differences in individual facility performance.

When modeling transmission compression, the NETL (2019b) study assumes a factor of 0.97 horsepower-hour (HPh)/thousand cubic feet (Mcf) to estimate the transmission station throughput (derived from NETL-published parameters). The average ratio of HPh to Mcf of throughput, from Cheniere Energy's known suppliers (used in the Roman-White et al. study) is 0.27 HPh/Mcf, which is based on supplier data collection completed. For modeling gas from other transmission operators, the GHGRP does not publicly provide the throughput of compressor stations. The Roman-White et al. (2021) study assumes 0.29 HPh/Mcf based on data reported by EIA.

The higher factor used by the NETL (2019b) study results in increased modeled fuel consumption across the transmission network. The Roman-White et al. liquefaction GHG intensity is 8–13 percent less than the intensity estimated by Gan et al. and is comparable to the NETL (2019) study estimate on a 100-year basis. The Roman-White et al. (2021) study concludes ocean transport stage emissions intensity is 42–60 percent less than the transport emissions intensity of Gan et al. (2020), and 35–42 percent less than that of the NETL (2019b) study. A separate study from Abrahams et al. (2015) notes that emissions from the shipping of LNG exports from the United States to ports in Asian and European markets account for only 3.5–5.5 percent of precombustion life cycle emissions; hence, Abrahams et al. (2015) concludes that shipping distance is not a major driver of GHGs in the LNG supply chain.

Jordaan et al. (2022) estimate global average life cycle GHG emissions from the delivery of gas-fired electricity to be 645 gCO_2e per kilowatt hour (kWh) (334–1,389 gCO_2e per kWh), amounting to 3.6 gigatonne CO_2e per year in 2017 (10 percent of energy-related emissions). This result is comparable to the results obtained by Roman-White et al. (2021), who report life cycle GHG emissions of 524 gCO_2e kWh for electricity produced in China using LNG supplied by U.S. LNG exporter Cheniere Energy, and 636 gCO_2e per kWh reported by NETL (2019b). Exhibit 2-10 summarizes these results.

Exhibit 2-10. LCA results comparison of LNG-derived electricity

LNG LCA Study	Mean gCO_2e per kWh
NETL (2019b)	636
Roman-White et al. (2021)	524
Jordaan et al. (2022)	645

Across these studies, the primary difference in the GHG results comes from assumptions about emissions associated with natural gas extraction and G&B portions of the natural gas supply chain.

2.4 METHANE EMISSIONS RESEARCH AND DEVELOPMENT

DOE's Methane Mitigation Technologies program aims to eliminate non-trivial CH_4 emissions from the oil and gas supply chain by 2030. These non-trivial CH_4 emissions include CH_4 production, processing, transportation, and use.

The Methane Mitigation Technologies program is focused on developing accurate, cost-effective, and efficient technology solutions and best practices to identify, measure, monitor and eliminate CH_4 emissions from these sources. Methane mitigation R&D efforts include advanced materials of pipeline construction, monitoring sensors, data management systems, and more efficient and flexible compressor stations. Research efforts for CH_4 emissions quantification focus on developing technologies to detect, locate, and measure emissions. This includes the development and validation of measurement sensor technologies for the collection, dissemination, and analysis of emissions data, which will inform efforts, such as the GHGI and orphan well remediation programs of EPA and DOI, respectively. The following three areas comprise DOE's current research, development, and demonstration (RD&D) efforts to identify, address, and reduce oil and natural gas sector emissions.

- Methane Emissions Quantification — activities focus on direct and remote measurement sensor technologies, data acquisition, research, and advanced analytics that quantify CH_4 emissions from point sources along the upstream and midstream portion of the natural gas value chain.
- Methane Emissions Mitigation — project investments and activities aim to develop advanced materials, data management tools, inspection and repair technologies, and advanced compressor technologies for eliminating fugitive CH_4 emissions across the natural gas value chain.
- Undocumented Orphaned Wells — cooperative RD&D efforts involving the Interstate Oil and Gas Compact Commission (IOGCC) are designed and implemented to assist the Federal land management agencies, States, and Indian Tribes in identifying and characterizing undocumented orphaned wells, primarily by developing and testing innovative technologies and approaches that locate and characterize orphaned wells to enable well plugging efforts being administered under DOI's Orphaned Well Plugging Program.

There are several mitigation measures available to address the GHG emissions from the natural gas supply chain, including equipment upgrades and process optimization.[p] Additionally, advancing technologies to detect and measure fugitive and vented CH_4 emissions can help to identify leaks and super emitters.

2.4.1 Detection and Measurement

Alvarez et al. (2018) note that key aspects of effective mitigation include pairing well-established technologies and best practices for routine emissions sources with economically viable systems to rapidly detect the root causes of high emissions arising from abnormal conditions. The latter could involve combinations of current technologies, such as on-site leak surveys by company personnel using optical gas imaging, deployment of passive sensors at individual facilities or mounted on ground-based work trucks, and in situ remote-sensing approaches using tower networks, aircraft, or satellites. Over time, the development of less failure-prone systems would be expected through repeated observation of, and further research into, common causes of abnormal emissions, followed by reengineered design of individual components and processes.

Roman-White et al. (2021) note that for LNG, harmonized data collection and reporting would build confidence in supplier claims about LCA emissions, enabling comparisons between natural gas supply chains and supporting climate goals for all participants in the supply chain. This could stimulate a virtuous cycle of demand for GHG accounting and reduction and provision of more granular, company-specific emissions estimates.

According to Stern (2022), three major requirements for creating credible measuring, reporting, and verification of CH_4 emissions are 1) to move measurement and reporting of CH_4 emissions from standard factors—either engineering-based or from EPA data—to empirical (Tier 3)

[p] Examples of equipment upgrades in this context include compressor seals, reciprocating compressors, and pneumatic controls.

measurements, and to reconcile bottoms-up (ground level) and top-down (satellite/aircraft/drone) observations; 2) to ensure that data measurement and reporting has been verified and certified by accredited bodies; and 3) to require asset-level emissions data to be transparent and publicly available. Failure to do so on grounds of commercial confidentiality risks being interpreted as evidence that the data is not credible.

2.4.2 Equipment Upgrades and Process Optimization

Compressor seals include wet seals used by centrifugal compressors and rod packing used by reciprocating compressors. Wet seals surround the rotating shaft of a centrifugal compressor with oil, which prevents gas leakage from the compressors. The oil used by wet seals must be continuously regenerated, which releases CH_4 into the atmosphere. By replacing wet seals with mechanical dry seals, the CH_4 emissions from centrifugal compressors can be reduced.

Reciprocating compressors prevent CH_4 leakage by encasing each compressor rod with a set of oil-coated, flexible rings. Proper maintenance and routine replacement of these rings prevents unnecessary leakage of CH_4. Storage tanks hold flowback water and liquid hydrocarbons recovered from the production stream. Variable loading levels and temperatures cause the venting of CH_4 and other gases from these tanks. By installing vapor recovery units on storage tanks, producers can more effectively reduce emissions from natural gas production. The captured emissions can be combusted on site to provide process energy, or they can be channeled to the sales stream.

Pneumatic controllers use gas pressure to open and close valves throughout a natural gas production and processing system. Natural gas is commonly used to pressurize pneumatic control systems. The bleeding of natural gas from pneumatic controllers leads to venting CH_4 to the atmosphere. The GHG impact of pneumatic control systems can be reduced by installing pneumatic systems that use pressurized air instead of pressurized natural gas.

Regulations mandate emissions reductions from pneumatically controlled valves and compressor seals. The data suggest that the use of this equipment reduces completion emissions by approximately 75−99 percent.

The practice of reduced emissions completions (RECs) utilizes equipment that allows the capture of gas during flowback, either to be sent to the product line or, if this is not feasible, to be flared. In the United States, the use of RECs is compulsory by law. REC implementation has shifted the emissions from CH_4 to CO_2; there is evidence it has reduced the GHG intensity of completions (Balcombe et al., 2016; Balcombe, Brandon, and Hawkes, 2018).

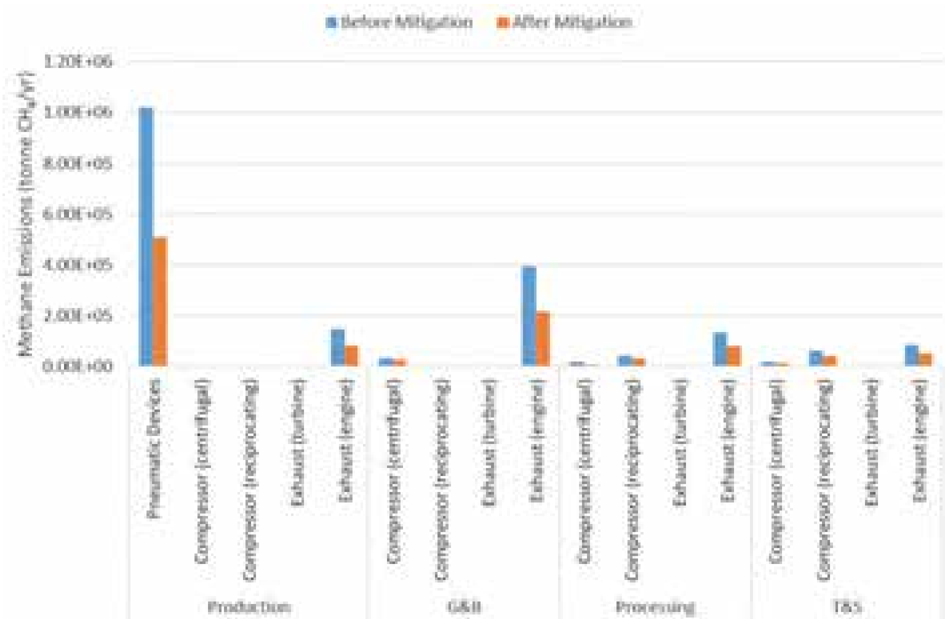
A 2020 report produced by NETL—Littlefield et al. (2020)—notes that compressed-air pneumatics are a mature technology that can reduce CH_4 emissions from pneumatic systems. The technology replaces existing devices, which are actuated by natural gas, with devices that are actuated with compressed air. This requires the addition of electric-powered air compressors at natural gas facilities but can result in zero CH_4 emissions from pneumatics. The same report notes that proven technologies exist for reducing CH_4 emissions from compression systems (as described below):

- Centrifugal compressors emissions can be reduced by replacing wet seals with dry seals. These seals are used around the rotating shaft of the compressor and prevent high pressure gas from escaping the compressor. Wet seals involve the use of recirculating oil that emits 40–200 standard cubic feet (scf) of natural gas per minute (min). Dry seals use gas to seal the compressor shaft and emit only 6 scf/min. The replacement of wet seals with dry seals reduces centrifugal compressor emissions by 85–97 percent.
- Reciprocating compressor emissions can be reduced by replacement of rod packing. Packing prevents gas from moving around piston rods and escaping the compression cylinder. New packing that is properly installed on a well-maintained compressor will emit about 12 scf/hour. The emissions rate for old or poorly installed packing can range 25–67 scf/hour. When compared to the emissions rate for new packing, this equates to potential emissions reductions of 52–82 percent. Rod packing replacement is a mature technology, but there are new technologies that can also reduce reciprocating engine exhaust slip. These new technologies include advanced materials that increase piston rod service life while reducing rod wear and Teflon-coated rings that reduce friction while maintaining a tight seal. There are no data currently available, however, on the emissions reduction potential tied to deploying these new technologies.
- The majority of the CH_4 emissions from reciprocating compressors are due to the CH_4 slip from engine exhaust. Comparing the exhaust emissions factors for rich burn and lean burn engines,[q] respectively, shows that rich burn engines have a combustion effectiveness of 97 percent and lean burn engines have combustion effectiveness of 99 percent. Air-fuel-ratio controls are an option for improving the combustion effectiveness of lean burn engines while keeping NOx emissions low. More research is required to understand the limits of air-fuel-ratio controls but, for this analysis, it is assumed that they can increase the combustion effectiveness of a lean burn engine by 97–99 percent.

Exhibit 2-11 illustrates the potential impact of these mitigation approaches (Littlefield et. al 2020).

[q] The terms rich-burn and lean-burn simply refer to the way in which the engine burns fuel—the air-to-fuel ratio. A rich-burn engine is characterized by excess fuel in the combustion chamber during combustion; a lean-burn engine is characterized by excess air in the combustion chamber during combustion.

Exhibit 2-11. Illustration of mitigation measure impact for pneumatic devices and compressors



Balcombe, Brandon, and Hawkes (2018) note that pre-emptive maintenance and a faster response to detection of high emissions are methods for reducing the impact of super emitters. Identifying a cost-effective solution is imperative, and much attention is being given to developing lower cost emissions monitoring and detection equipment. As Brandt, Heath, and Cooley (2016) point out, identifying larger leaks from the highest emitters may be carried out using less sensitive, and consequently cheaper, detectors in areas representing the highest risk.

2.4.3 Liquefaction Emissions Mitigation Measures

With respect to liquefaction, Mokhatab (2014) note that most of the plant energy consumption and resultant emissions in natural gas liquefaction facilities occur in the compressor drivers, where fuel energy (usually natural gas) is converted to mechanical work (or electricity in case of electrically driven compressors). Due to the energy consumption scale of the LNG plants, any enhancement to the energy efficiency of a plant will result in a significant reduction in gas consumption and consequently CO_2 emissions (Mokhatab, 2014).

There are two ways to increase the energy efficiency of LNG plants: 1) liquefaction cycle enhancement and 2) driver cycle enhancement. Liquefaction cycle enhancements reduce compressor power and consequently the compressor driver's fuel consumption. Driver cycle enhancement reduces the amount of fuel consumption to generate a specific amount of power.

Typical fuel sources for natural gas liquefaction cycles include either pure refrigerant in cascade cycles, expansion-based cycles, or mixed refrigerant cycles.

Pure refrigerant cycles have a constant evaporating temperature that is a function of the saturation pressure. Mixed refrigerant cycles do not maintain a constant evaporating temperature at a given pressure. Their evaporating temperature can range and change depending on the pressure and composition. A refrigerant mixture of hydrocarbons and nitrogen is chosen so that it has an evaporation curve that matches the cooling curve of the natural gas with the minimum temperature difference. Therefore, small temperature differences reduce entropy generation and, thus, improve thermodynamic efficiency, reduce power consumption, and reduce the emissions associated with liquefaction facilities (Mokhatab 2014).

A study from Pospíšil et al. (2019) notes that a certain part of the energy spent on liquefaction can be recovered by the utilization of the cold stream from LNG. The amount of usable cold is given by thermophysical properties of natural gas and corresponds to 830 kilojoule (kJ)/kg of LNG. This cold energy can be recovered during the regasification process.[r] Regasification is carried out either in port terminals before natural gas is transported via gas lines or directly before the use of natural gas. The exploitation of cold from LNG is quite limited at present. Most of the available cold is wasted during the regasification process when LNG is heated up by water or ambient air. Inefficient use of cold temperature streams reduces the overall efficiency of this primary energy source and leads to greater emissions. Pospíšil et al. (2019) recommends that promising ways of utilizing cold from LNG in the regasification process should be explored and implemented (Pospíšil et al., 2019).

As noted in Chapter 1, in April 2023, FECM issued an RFI to obtain input to inform DOE's R&D activities related to information on strategies and technologies that natural gas and LNG companies are deploying, or could deploy, to reduce GHG emissions and other air pollutants associated with natural gas delivered to liquefaction facilities, housed at liquefaction facilities, and being loaded, transported, and delivered to regasification facilities (DOE, 2023). Information from that RFI is currently being reviewed and could add to the information summarized here.

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[r] LNG is kept in liquid form through maintaining a storage and transport temperature of approximately -160 °C. When LNG is regasified, there are hot and cold "streams" in the process. Through heat-integration (using heat exchangers, for example), one can utilize a hot or cold stream of a thermochemical process to supply or remove heat from another part of the process.

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3 AIR QUALITY

There are two primary air emissions pathways from sources in the natural gas supply chain 1) the leaking, venting, transport, and combustion of natural gas; and 2) the combustion of natural gas and other fossil fuel resources or other emissions during associated operations (e.g., extraction, transportation, downstream combustion). Emissions sources include pad, road, and pipeline construction; well drilling, completion, and flowback activities; and natural gas processing and transmission equipment such as controllers, compressors, dehydrators, pipes, and storage vessels. Pollutants include, most prominently, CH_4 and volatile organic compounds (VOCs)—of which the natural gas industry is one of the highest-emitting industrial sectors in the United States—in addition to NOx, sulfur dioxide (SO_2), and various forms of other hazardous air pollutants (HAPs) (Congressional Research Service [CRS], 2020). Pollutants are described in detail below (CRS, 2020):

- CH_4 is the principal component of natural gas and is a precursor to ground-level ozone formation (i.e., "smog").
- NOx is a ground-level ozone precursor.[s] Significant amounts of NOx are emitted during the combustion of natural gas and other fossil fuels (e.g., diesel). The combustion of natural gas occurs when it is flared during drilling and well completions and when used to drive the various compressors that move products through the system. Combustion also occurs in engines, drills, heaters, boilers, and other production equipment.
- VOCs are a ground-level ozone precursor. The crude oil and natural gas sector is currently one of the largest sources of VOC emissions in the United States, accounting for approximately 20 percent of man-made VOC emissions nationwide (and representing almost 40 percent of VOC emissions released by stationary sources).[t] VOCs—in the form of various hydrocarbons—are emitted throughout a wide range of natural gas operations and equipment. The interaction among VOCs, NOx, and sunlight in the atmosphere contributes to the formation of ozone.
- SO_2 is emitted from crude oil and natural gas production and processing operations that handle and treat sulfur-rich, or "sour," gas.
- HAPs[u], also known as air toxins, are those pollutants that are known or suspected to cause cancer or contribute to other serious health effects including reproductive issues and birth defects. The most common HAPs produced from natural gas systems are n-hexane and benzene, toluene, ethylbenzene, and xylenes (BTEX) compounds. Some natural gas reservoirs may also contain high levels of hydrogen sulfide (H_2S). HAPs are

[s] NOx is the collective term for the nitrogen oxides nitrogen monoxide and nitrogen dioxide.

[t] EPA's 2014 National Emissions Inventory estimated VOC emissions from "oil and gas" stationary sources to be 3.23 MM tons, from all stationary sources to be 8.26 MM tons, and from all anthropogenic sources to be 16.48 MM tons. Data for VOCs, as well as the other criteria pollutants and HAPs, are derived from EPA's National Emissions Inventory, available at https://www.epa.gov/sites/production/files/2017-04/documents/2014neiv1_profile_final_april182017.pdf.

[U] EPA has a list of over 180 chemicals they determined are toxic air pollutants, or HAPs. Some VOCs are included on that list, so the two concepts (HAPs and VOCs) are not mutually exclusive.

found primarily in natural gas itself and are emitted from equipment leaks and during processing, compressing, transmission, distribution, or storage operations. HAPs are also a byproduct of incomplete fuel combustion and may be components in various chemical additives.

3.1 UPSTREAM PRODUCTION AND HYDRAULIC FRACTURING

The venting of natural gas during extraction and processing is a key source of VOC emissions. Similar to CH_4, VOCs are a naturally occurring constituent of natural gas and can react with other pollutants to produce ground-level ozone. Another source of VOC emissions during upstream operations is venting from condensate storage tanks, which occurs in regions with wet gas.[v]

The combustion of natural gas in compressors and gas processing equipment produces NOx and carbon monoxide (CO). Similarly, the combustion of diesel in drilling equipment produces NOx and CO, as well as significant quantities of SO_2 emissions. Beyond VOCs, CH_4, NOx, CO, and SO_2 emissions, upstream processes can also produce aliphatic hydrocarbons, (e.g., C2–C5), alkanes, VOCs (e.g., BTEX), H_2S, n-hexane, and formaldehyde, which can contaminate ambient air (Wollin et al., 2020).

Elliott et al. (2017) estimates that up to 143 air contaminants can be released during hydraulic fracturing. The International Agency for Research on Cancer generates hazard assessments for only 20 percent of these identified contaminants. Twenty of these air contaminants are known carcinogens. Other air contaminants are generated by the peripheral plant components. These include particulate matter, NOx, precursors of ozone and polycyclic aromatic hydrocarbons (Wollin et al., 2020).

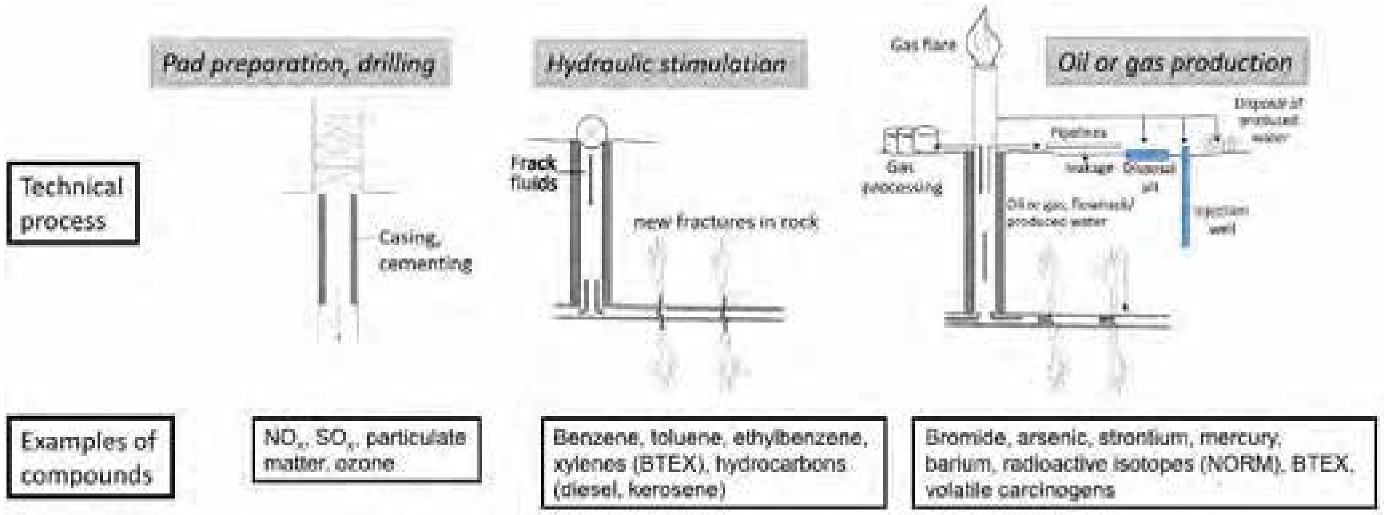
The following activities are known to contribute to air contamination at oil or gas drilling sites:

- Preparation of the drilling site including road connections
- Drilling of the well
- Truck traffic for delivery and disposal of materials
- Removal of acid gases and water from gas; separation of natural gas from other hydrocarbons
- Operation of compressor stations to enable the transport of natural gas into transport pipelines
- Preprocessing of crude oil prior to refinery.

Exhibit 3-1 illustrates the supply chain for natural gas where each of these activities occurs (Wollin, 2020).

[v] When natural gas is retrieved, it can be considered wet or dry. Dry natural gas is at least 85 percent CH_4, but often more. Wet natural gas contains some CH_4, but also contains liquids such as ethane, propane, or butane. The more CH_4 natural gas contains, the "dryer" it is considered.

Exhibit 3-1. Illustration of supply chain steps where upstream air pollution occurs



Used with permission from Wollin et al. (2020)

NOx and SOx emissions have been reported to be higher during the development of the drilling site compared to during the production phase (Wollin et al., 2020). Similar observations have been made for particulate matter (PM) (e.g., PM2.5 and PM10). Analysis of shale gas production sites in North Texas showed an 8 percent increase in ozone concentrations at natural gas production sites compared to control sites (Wollin et al., 2020).

Indirect energy consumption can also affect the air quality profile of gas extraction technologies. If the development or operation of a natural gas well uses grid electricity, then the fuel mix of the electricity grid will affect the life cycle performance of the well. The indirect air quality impacts of electricity consumption depend on the fuel mixes and combustion characteristics of power plants that collectively compose a regional electricity grid. Exhibit 3-2 offers a perspective on sources of non-GHG air pollutants by supply chain step or equipment.

Exhibit 3-2. Perspective of non-GHG air pollutant by supply chain step or equipment

Source	Air pollutant				Data quality
	NO_X	VOC	PM	Other toxic substances	
Well development					
Drilling rigs	●	◦	●	●	Medium
Frac pumps	●	◦	●	●	Medium
Truck traffic	●	◦	●	●	Medium
Completion venting		●		●	Poor
Frac ponds		◦			Poor
Gas production					
Compressor stations	●	●	◦	●	Medium
Wellhead compressors	◦	◦	◦	◦	Medium
Heaters, dehydrators		◦	◦	◦	Medium
Blowdown venting		◦		◦	Poor
Condensate tanks		●		◦	Poor
Fugitives				◦	Poor
Pneumatics		◦		◦	Poor

● Major source, ◦ minor source

Used with permission from Wollin et al. (2020)

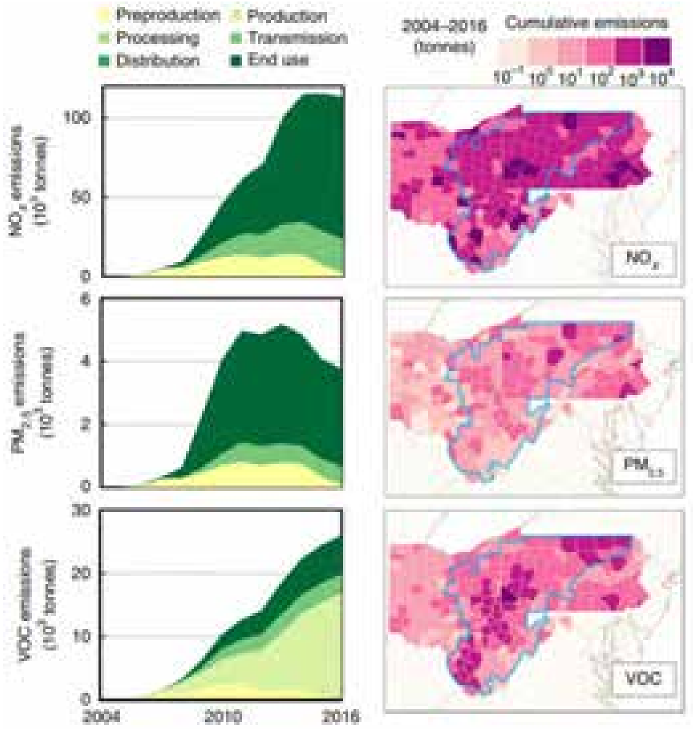
McMullin et al. (2018) analyzed exposure to VOCs emitted during hydraulic fracturing in Colorado. They identified 56 different VOCs that were emitted during hydraulic fracturing using data compiled from 47 existing air monitoring devices that measured these VOCs at 34 different locations across the region.

Plant et al. (2022) used airborne sampling to measure flare efficiency[w] in three major gas production regions in the United States. They found that both unlit flares and inefficient combustion contribute comparatively to ineffective CH_4 destruction, with flares effectively destroying only 91.1 percent (90.2–91.8 percent; 95 percent confidence interval) of CH_4 emissions. Other emissions from flaring can include carbon particles (soot), unburned hydrocarbons, CO, partially burned and altered hydrocarbons, NOx, and (if sulfur containing material such as H_2S or mercaptans is flared) SO_2. The combustion products of flaring at natural gas production and processing sites specifically include CO_2, CH_4, and N_2O.

Mayfield et al. (2019) performed an analysis of the environment impacts associated with the shale gas boom in the Appalachian Basin and found the majority (61 percent) of VOC emissions from the natural gas supply chain can be largely attributed to upstream processes and are spatially concentrated in counties with the highest cumulative production. Upstream processes contribute the most to total NOx (67 percent) and PM2.5 (73 percent) emissions across the natural gas supply chain; NOx and PM2.5 emissions are relatively evenly distributed across counties (Mayfield et al., 2019). Exhibit 3-3 presents annual NOx, PM2.5, and VOC emissions from the natural gas supply chain within Pennsylvania, Ohio, and West Virginia, along with the spatial distribution of cumulative NOx, PM2.5, and VOC emissions by county between 2004 and 2016. It is important to note that the blue lines delineate shale gas-producing counties (Mayfield et al., 2019).

[w] The flare efficiency is a measure of the effectiveness of the combustion process to fully oxidize the fuel. When inefficiencies occur, unburned fuel, CO, and other products of incomplete combustion (e.g., soot, VOCs, etc.) are emitted into the atmosphere.

Exhibit 3-3. Annual (left graphs) and cumulative (right graphs) (2004–2016) NOx, PM2.5, and VOC emissions from natural gas supply chain within Pennsylvania, Ohio, and West Virginia



Permission pending from Mayfield et al. (2019)

3.2 MIDSTREAM TRANSPORT EMISSIONS

CH_4 leakage in the transmission and distribution systems is documented in Chapter 2 – Greenhouse Gas Emissions. This mid-stream segment leakage has important air pollutant considerations, since CH_4 can be a precursor to ground-level ozone formation.

While the presence of HAPs in unprocessed, upstream natural gas has been documented, little has been published on their presence in the midstream segments of the natural gas supply chain. Nordgaard et al. (2022) systematically evaluated publicly available, industry-disclosed HAP composition data from natural gas infrastructure applications submitted to FERC between 2017 and 2020. These applications covered 45 percent of the U.S. onshore natural gas transmission system (as measured by pipeline miles). Given that reporting HAP composition data is not required by FERC, only 49 percent of approved projects disclosed their HAP composition data to FERC. Of the applications that did disclose their HAP composition data, HAP concentrations were typically reported as higher for separator flash gas and condensate tank vapor, compared to LNG and transmission-grade natural gas, with mean benzene concentrations of 1,106, 7050, 77, and 37 parts per million (ppm), respectively.

Nordgaard et al. (2022) also identified one pipeline operator that reports real-time HAP concentrations for natural gas at five pipeline interconnection points. Similar to the FERC applications, this operator reported BTEX and H_2S as present in the pipelines used to transport their natural gas. Because current transmission infrastructure releases natural gas during uncontrolled leaks, loss of containment events, and routine operations (e.g., blowouts and compressor station blowdowns), having access to HAP composition data may be important for conducting both air quality and health-focused evaluations of natural gas releases.

3.3 Air Emissions Research and Development

Many of the strategies to reduce air emissions from oil and natural gas operations are similar to those identified to reduce GHG emissions. For example, improved flaring efficiency can reduce air emissions and measures to reduce CH_4 emissions will also reduce VOCs and other hazardous pollutants that are emitted with CH_4.

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4 WATER USE AND QUALITY

The literature describes the treatment and management of wastewaters as a central environmental concern regarding natural gas production. Especially in the eastern regions of the United States where—although water resources are abundant—significant natural gas production has been occurring and is expanding. In the western parts of the United States, persistent dry climates limit the use and availability of freshwater for natural gas production—specifically, freshwater availability for drilling and hydraulic fracturing.

Gallegos et al. (2015) estimate that drilling and hydraulically fracturing a shale gas well can consume 2.6–9.7 MM gallons (gal) of water. From 2014 to 2015, unconventional shale gas in the United States used 187 billion (B) gal of water. From 2012 to 2014, the average use of water for hydraulic fracturing was 30.6 B gal annually. Additionally, Gallegos et al.'s (2015) integrated data from 6–10 years of operations suggests 212 B gal of produced water[x] are generated from unconventional shale gas and oil formations.

While extensive growth in hydraulic fracturing has increased water use for natural gas production across the United States, the water use and produced water intensity of these well-stimulation activities is lower than the water use and produced water intensity of other energy extraction methods and represents only a small fraction of total industrial water use nationwide (Kondash and Vengosh, 2015). However, given the amount of water required for natural gas production, local or seasonal water supply shortages can cause issues.

Water quality can also be impacted by natural gas production processes if water is inadequately managed or by the use of fracturing chemicals both on the surface (e.g., if chemicals are inadvertently spilled and not contained)—before injection and after flowback—and in produced water. Subsurface water quality impacts can result from the migration of fracturing fluids, formation waters, and CH_4 along well bores and through rock fracture networks. Management and disposal efforts increasingly include efforts to minimize water use through recycling and re-use of fracturing fluids, in addition to treatment and disposal of wastewater through deep underground injection.

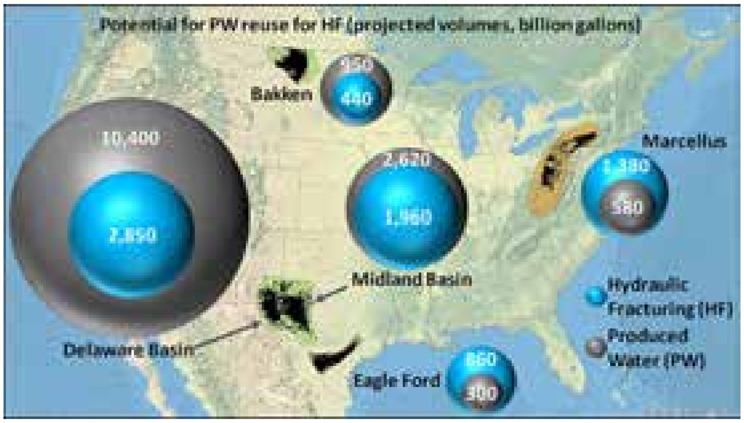
Scanlon et al. (2020a) analyze the water-related sustainability of energy extraction. They focus on meeting the rising water demand for hydraulic fracturing and managing growing volumes of water co-produced with oil and gas. They also analyze historical (2009–2017) volumes of water in ~73,000 wells and project future volumes of water use in major U.S. unconventional oil and gas plays. Their results show a marked increase in water use for fracking, depleting groundwater resources in some semi-arid regions (Scanlon et al., 2020a).

Water issues related to both fracking water demand and produced water supplies may be partially mitigated through the reuse of produced water to frack new wells. As shown in Exhibit 4-1, projected produced water volumes exceed fracking water demand in semi-arid Bakken (2.1×), Permian Midland (1.3×), and Delaware (3.7×) oil plays, with the Delaware oil play

[x] Produced water is defined as the water that is withdrawn through oil and gas extraction. Produced water can begin as ground water within the hydrocarbon bearing formations; however, as the extraction matures, or in the case of shale or tight formations where hydraulic fracturing is necessary to liberate the hydrocarbons, produced water can also contain fluids that were previously injected.

accounting for ~50 percent of the projected U.S. oil production (Scanlon et al., 2020a). Therefore, water issues could impact future energy production, particularly in semi-arid oil plays.

Exhibit 4-1. Map showing ratio between produced water and fracking water demand for major shale basins



Used with permission from Scanlon et al. (2020a)

4.1 Water Use for Unconventional Natural Gas Production

The process of hydraulic fracturing uses large volumes of water mixed with chemicals and proppant (sand) to fracture low-permeability shale and tight oil rocks, allowing the extraction of hydrocarbons. Despite the higher water intensity (the amount of water used to produce a unit of energy; for example, liters per gigajoule) compared to drilling conventional vertical oil and gas wells, overall water withdrawals for hydraulic fracturing is negligible compared to other industrial water uses on a national level (Vengosh et al., 2014; Jackson et al., 2014; Kondash, Albright, and Vengosh, 2017; Kondash and Vengosh, 2015). On a local level, however, water use for hydraulic fracturing can cause conflicts over water availability, especially in arid regions such as the western and southwestern United States where water supplies are already limited (Scanlon, Reedy, and Nicot, 2014; Ikonnikova et al. 2017; Nicot and Scanlon, 2012; Kondash, Lauer, and Vengosh, 2018).

Most of the water used for unconventional natural gas production is used as part of the hydraulic fracturing process. For example, of the total water used by the shale gas industry, hydraulic fracturing is estimated to account for about 89 percent, drilling about 10 percent, and infrastructure 1 percent (Hayes and Severin, 2012). Water is the main component of the fluids used for hydraulic fracturing, making up approximately 99 percent of the total volume.

Reporting from Gallegos, et al. (2015) suggests hydraulic fracturing uses 2.6–9.7 MM gal of water per well drilled, while the American Petroleum Institute (API) (API, 2023) suggests the average hydraulically fractured well uses 4 MM gal of water. It is important to consider the potential environmental impacts of using water from different sources (e.g., ground water, surface water). If available surface water is used to support natural gas production, then the ecosystems that rely on this water could be impacted. Significant groundwater withdrawals can permanently deplete aquifers.

4.1.1 Water Use Impacts

Water use for hydraulic fracturing and wastewater production in major shale gas and oil producing regions increased between 2011 and 2016, with water use per well increasing by up to 770 percent—and with flowback and produced water volumes generated within the first year of production increasing up to 550 percent. Water-use intensity (that is, normalized to energy production) increased in all U.S. shale basins, except the Marcellus shale basin, over this period (Kondash, Lauer, and Vengosh, 2018).

Water consumption per shale gas well can vary due to four primary factors:

- Geology: maturity of the shale and formation depth, thickness, and lateral extent
- Technology: horizontal or vertical drilling, water recycling
- Operations: operator decisions, availability of nearby freshwater
- Regulatory: requirements for use and treatment of water

During 2009−2017, ∼73,000 wells, or an aggregated total lateral length of ∼440 × 10^6 ft (134,000 km) equivalent to ∼3× the Earth's circumference (40,000 km), was drilled in eight plays studied by (Dieter et al., 2018). Dieter et al. (2018) found that to fracture the rock along that length, ∼480 B gal of water are required, equivalent to ∼0.1 percent of the U.S. 2015 total water withdrawal, or almost two days of freshwater withdrawal (280 B gal/day).

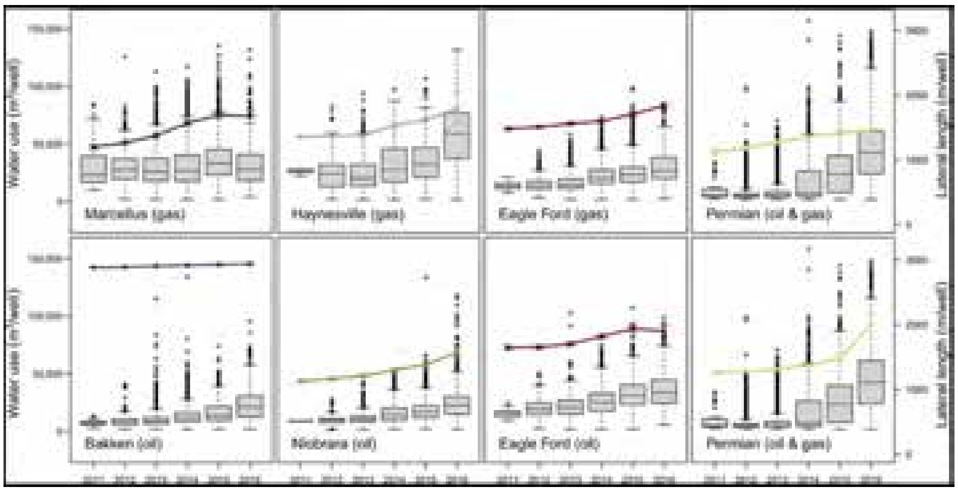
Exhibit 4-2 shows the water use for hydraulic fracturing, the amount of produced water used and oil and gas outputs from nine major plays in the United States from 2009 to 2017 (Scanlon et al., 2020a). The Eagle Ford play has used 173 B gal of combined hydraulic fracturing and produced water, at nearly a 1.83 ratio of freshwater to produced water and the Marcellus has a freshwater to produced water ratio of 5.83. Other plays use more produced water than freshwater, like Bakken, Delaware, and Barnett, where the ratios of produced water to freshwater are 1.83, 2.21, and 2.11, respectively.

Exhibit 4-2. water use in nine shale plays in the U.S.

Play	Total Length (10^6 ft)	Median Well Length (ft)	Number of Wells	Hydraulic Fracturing Water (10^9 gal)	Produced Water (10^9 gal)	Oil (10^9 gal)	Gas (10^9 gal of oil equivalent)
Bakken	114	9,580	12,036	49	75	100	22
Eagle Ford	95	6,061	17,366	112	61	103	78
Midland	49	8,575	6,461	79	44	30	14
Delaware	36	5,272	7,070	51	113	40	26
Marcellus	51	7,139	9,651	70	12	3	214
Niobrara	21	7,438	3,842	21	5	14	11
Barnett	27	5,241	7,453	35	74	1	111
Haynesville	15	6,270	3,215	30	16	0.03	107
Fayetteville	21	6,386	4,717	24	–	–	55

Exhibit 4-3 from Kondash, Lauer, and Vengosh (2018) indicate that, parallel to the increase in lateral lengths of the horizontal wells and hydrocarbon extraction yields through time, water use has also increased. The relative increase in lateral length (4–60 percent) was, however, significantly lower than the increase in water use (14–770 percent). When water use per well was normalized to the length of lateral section of the horizontal well, in almost every case among oil producing regions, an increase in water use per length of the horizontal well is observed. This pattern was most evident in the Permian region, where water use increased from 4.4 cubic meters (m^3) per meter in 2011 to 29.3 m^3 per meter in 2016 for gas-producing wells (an approximate seven-fold increase), and from 3.9 m^3 per meter in 2011 to 21.1 m^3 per meter in oil-producing wells (an approximate five-fold increase). In all cases, with the exception of the Marcellus shale play in 2016, the flowback and produced water generation also increased through time, with particularly higher rates after 2014.

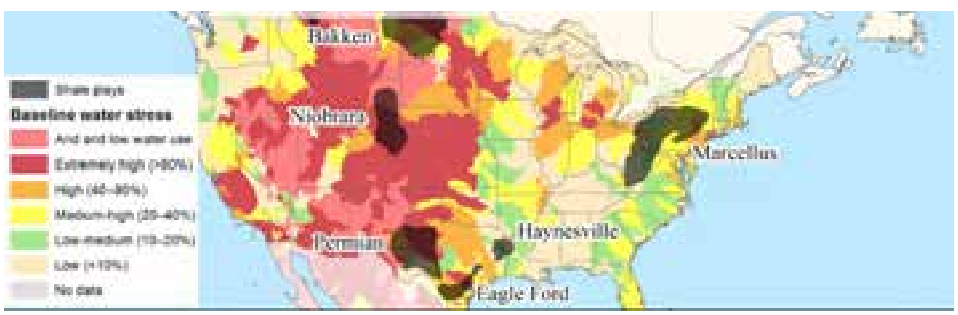
Exhibit 4-3. Water usage and lateral length by shale play



Used with permission from Kondash, Lauer, and Vengosh (2018)

Kondash, Lauer, and Vengosh (2018) also illustrate water conditions where the major plays across the United States are located, see Exhibit 4-4. The Bakken, Niobara, Permian and Eagle Ford plays are all located in arid to extremely dry climates where drought conditions have persisted for many years.

Exhibit 4-4. Baseline water stress and location of shale plays



Used with permission from Kondash, Lauer, and Vengosh (2018)

4.1.2 Water Quality

Concerns have been raised about potential public health effects that may arise if hydraulic fracturing-related chemicals were to impact drinking water supplies. The chronic oral toxicity values—specifically, chronic oral reference values (RfVs) for noncancer effects, and oral slope factors (OSFs) for cancer are available for the list of 1,173 chemicals EPA identified as "associated with hydraulic fracturing." These include 1,076 chemicals used in hydraulic fracturing fluids and 134 chemicals detected in the flowback or produced waters from hydraulically fractured wells.

EPA compiled RfVs and OSFs for these chemicals using six different governmental and intergovernmental data sources. Ninety (8 percent) of the 1,076 chemicals used in hydraulic fracturing fluids and 83 (62 percent) of the 134 chemicals found in flowback/produced water had a chronic oral RfV or OSF reported in at least one or more of the six data sources used. Thirty-six of the chemicals used in hydraulic fracturing fluids have been measured in at least 10 percent of the hydraulically fractured wells drilled nationwide (identified from EPA's analysis of the FracFocus Chemical Disclosure Registry 1.0). Eight of these 36 chemicals (22 percent) had an available chronic oral RfV. The lack of chronic oral RfVs and OSFs for the majority of these chemicals highlights the significant knowledge gap that exists to assess the potential human health hazards associated with hydraulic fracturing (Yost et al., 2016).

Ecological risks to surface waters are present throughout the well life cycle and may manifest themselves differently locally compared to regionally. These risks can also vary temporally, as development activity like surface water withdrawal may only result in a single, brief impact, while the network of roads required for accessing well pads could increase erosion and sediment runoff for years. Previous work identified the primary risks to surface water quality as sediment runoff from devegetation, leakage and spillage of chemicals into surface waters, unsustainable water withdrawal, landscape fragmentation, and insufficient treatment of oil and gas wastewater prior to discharge (Krupnick, Gordon, and Olmstead, 2013; Slonecker et al., 2012; Drohan et al., 2012; Kiviat, 2013). Unfortunately, few sites exist where baseline environmental monitoring occurred prior to hydraulic fracturing operations commencing, greatly complicating efforts to precisely quantify the impacts of hydraulic fracturing, particularly if these operations are occurring in watersheds with preexisting anthropogenic influence and a host of existing ecological stressors (Mauter et al., 2014; McBroom, Thomas, and Zhang, 2012).

The surface water risks and impacts associated with unconventional resource development vary significantly by region (Clements, Hickey, Kidd, 2012). To date, those in the Marcellus region have been examined most extensively. This scrutiny has been motivated by the nexus of regionally specific risk drivers, such as high gradient terrains that could lead to increased erosion, an abundance of small streams, highly variable in-stream flow rates, and the high salinity of produced water in the Marcellus. Moreover, during the early development of the Marcellus shale in Pennsylvania, the state permitted the disposal of hydraulic fracturing brines in municipal wastewater treatment plants. The most recent studies suggest that to reduce the human and environmental impacts associated with this original practice, the State of Pennsylvania asked companies to adopt a moratorium on the disposal of produced water in wastewater treatment plants in the state (Wilson and Van Briesen, 2012; Wilson, Wang, and Van Briesen, 2013; Warner et al., 2013a; Wilson and Van Briesen, 2013; Renner, 2009 Abdalla et al., 2016).

The rapid development of unconventional gas extraction has increased the flux of both solid and liquid waste, fluxes proportionally much greater than those generated from traditional conventional well development on a per well basis. Drill cutting wastes from unconventional wells may contain more total naturally occurring radioactive materials (NORM) than conventional wells for two reasons. Geochemically, the shale itself contains more NORM than sandstone and limestone reservoirs holding conventional reserves (Badertscher et al., 2023; Huang et al., 2017). Physically, the horizontal bore is usually much longer than the vertical bore, and a larger proportion of the drill cuttings comprises the NORM rich shale due to the directional drilling. The Pennsylvania Department of Environmental Protection (PADEP) reported drill cuttings with the following ranges: ^{226}Ra (below detection limit to 640 becquerels/kg) and ^{228}Ra (0.37–104 becquerels/kg) (PADEP, 2016).

Higher NORM values in solids and liquids resulted in higher downstream values of ^{226}Ra and ^{228}Ra as well. Stream water and sediments in areas bracketing outfalls of facilities treating waste from landfills accepting oil and gas waste indicate accumulation of NORM in the sediments. Given distance from the outfall, these accumulations are of similar magnitude to those downstream of brine treatment facilities reported in the literature (Warner et al., 2013b) and indicate additions from a low ^{228}Ra/^{226}Ra activity ratio source, consistent with Marcellus formation sources (Lauer, Warner, and Vengosh, 2018).

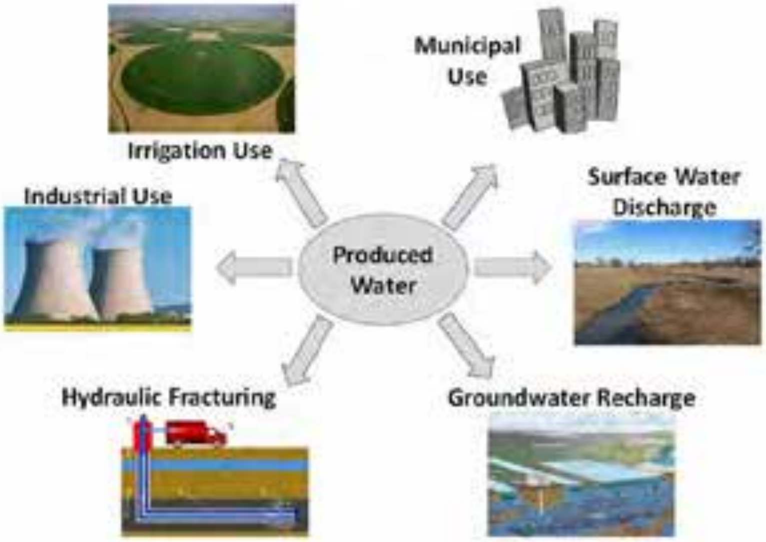
4.1.3 General Guidelines for Leading Best Practices on Water Remediation

Increasing demand for water for drilling and hydraulic fracturing in shale gas plays has driven operators to seek supplemental sources of water and alternatives to local freshwater supplies. Potential alternatives include industrial wastewater, water treatment plant outflows, abandoned mine waters, saline groundwater, and reuse of produced waters.

A 2023 report by the Groundwater Protection Council (GWPC) summarizes the most notable changes in produced water operational and management practices in each major production region (GWPC, 2023). The regions include both oil and gas production, with the Permian basin being the largest produced water region, producing 10.5 times more than the Bakken, 16.4 times more than the Eagle Ford, and 49 times more than the Appalachian region.

With many of these plays being in areas where water scarcity is an issue, reducing water consumption is critical. Therefore, produced water reuse technologies are critical as well. Once produced water is treated to fresh water or discharge standards, it can be reused. Exhibit 4-5 shows the major reuse outlets for treated produced water (Scanlon et al., 2020b).

Exhibit 4-5. Major produced water reuse outlets



Used with permission from Scanlon et al. (2020b)

When it comes to the beneficial reuse of produced water in any of the major development basins, the primary challenge to overcome is the desalination of the water by way of treatment and managing the associated products and wastes that are generated. Aside from the regulatory and liability challenges associated with the discharge of produced water, there are significant technical and economic challenges associated with large-scale produced water desalination systems. All the options for reuse shown in Exhibit 4-5 require the water to first meet a low salinity standard. The primary challenge faced by the beneficial reuse of produced water is the removal of total dissolved solids (TDS) or dissolved salt from the produced water matrix. Exhibit 4-6 shows the salinity ranges for different types of water (Horiba, 2016).

Exhibit 4-6. Different types of water salinity values

Salinity Status	Salinity (%)	Salinity (parts per trillion)	Use
Fresh	<0.05	< 0.5	Drinking and all irrigation
Marginal	0.05–0.1	0.5–1.0	Most irrigation, adverse effects on ecosystems become apparent
Brackish	0.1–0.2	1–2	Irrigation for certain crops only, useful for most livestock
Saline	0.2–1.0	2–10	Useful for most livestock
Highly Salinated	1.0–3.5	10–35	Very saline groundwater, limited use for certain livestock
Brine	> 3.5	> 35	Seawater, some mining and industrial uses exist

Produced water requires significant pretreatment prior to being subjected to any desalination process. The most prominent and proven water desalination technology deployed across the world is reverse osmosis, which becomes increasingly inefficient when TDS concentrations exceed 35,000 ppm (which is reflective of the salinity concentration in seawater). As the overwhelming amount of produced water in the United States is well above the levels to be treated by reverse osmosis, including produced water in the Permian (median TDS concentration: 154,000 ppm), this technology is not applicable.

Thermal (vapor) distillation would be considered “mature and proven” for this application. These distillation technologies typically consist of a mechanical vapor compression/mechanical vapor recompression component and have been in use for more than a decade in the oilfield treating produced water with limited acceptance due to throughput and costs. Thermal distillation technologies often require extensive pretreatment of the water before processing, including the removal of hydrocarbons, total suspended solids, and all hardness cations.

4.2 Current Water Research and Development

DOE funds R&D to advance sustainable water management technologies and approaches, responding to increased water demand from decarbonized power generation. Additionally, DOE seeks to provide alternative water resources in water-stressed areas by treating wastewaters from fossil energy activities, making those treated wastewaters available to end-users outside the fossil energy industry, and reducing environmental impacts of fossil fuel generation during the transition to clean energy. To accomplish these goals, DOE currently has R&D focused in three areas:

1. Characterization, treatment, and management of produced waters
2. Recovery of critical minerals – including rare earth elements and other resources for beneficial reuse
3. Alternative water resources and identifying opportunities to utilize them

The Produced Water Optimization Initiative (PARETO) is an optimization framework for produced water management and opportunities for beneficial use. The goal of PARETO is to develop a modeling and optimization application to identify cost-effective and environmentally sustainable produced water management, treatment, and reuse solutions.

PARETO will help with the following tasks:

- Buildout of the produced water infrastructure
- Management of produced water volumes
- Selection of effective treatment technologies
- Placement and sizing of treatment facilities
- Identification of beneficial water reuse options
- Distribution of treated produced water for reuse.

The Water Management for Power Systems program will lead the critical national R&D effort directed at removing barriers to sustainable, efficient water and energy use at fossil power plants by developing technology solutions and enhancing the understanding of the relationship between energy and water resources.

DOE and NETL will work together to overcome the following challenges:

- Reduce freshwater consumption by 50 percent
- Lower the cost of treating fossil power plant effluent streams by 50 percent

The produced water characterization effort will focus on the critical national R&D effort directed at characterizing produced water associated with sustainable oil and gas development. The work proposed is aligned with DOE-FECM's program goals to reduce freshwater consumption and to recover valuable resources from both effluent and alternative influent water streams. Leveraging its core capabilities, competencies, and authorities, NETL will move to partner with universities and industry to develop and increase the commercial readiness of technology options needed to treat and manage produced water from oil and natural gas operations.

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5 Induced Seismicity

Among the many impacts of anthropogenic activity on the Earth, one that has caused particular public disquiet in recent years is "induced seismicity," that is, minor earthquakes and tremors caused by industrial processes (Grigoli and Wiemer, 2017). Earthquakes have been detected in association with both oil and natural gas production, underground injection of wastewaters (i.e., wastewater disposal), and hydraulic fracturing (Rubinstein and Mahani, 2015). Each of these processes involves injecting large volumes of fluids at various pressures into underground formations.[y] Earthquakes from human activities have happened in multiple countries, including the United States (Shultz et al., 2020).

5.1 Impacts from Induced Seismicity and Energy Technologies

The term seismic activity is generally used to describe vibrations of mechanical energy that pass through the earth, much like sound waves vibrate through the atmosphere. The seismic activity of a region is defined by the frequency, kind, and magnitude of earthquakes experienced in the region during a given period. The National Earthquake Information Center (NEIC) is the entity responsible for determining, as rapidly and as accurately as possible, the location and size of all significant earthquakes that occur worldwide. At present, the NEIC locates and publishes detailed data on the 30,000 "most significant" earthquakes that occur in each year (USGS, 2023).

While millions of earthquakes occur each year, not all are felt at the surface. Earthquakes with magnitudes of 2.0 or less generally cannot be felt at the surface by people, while earthquakes with magnitudes greater than 3.0 tend to produce noticeable shaking. Earthquakes with magnitudes greater than 5.0 are felt at the surface and have the potential to cause structural damage to buildings and property. Most earthquakes that do occur are in response to natural, yet sudden slips and shifts of large masses of rock along geologic faults.

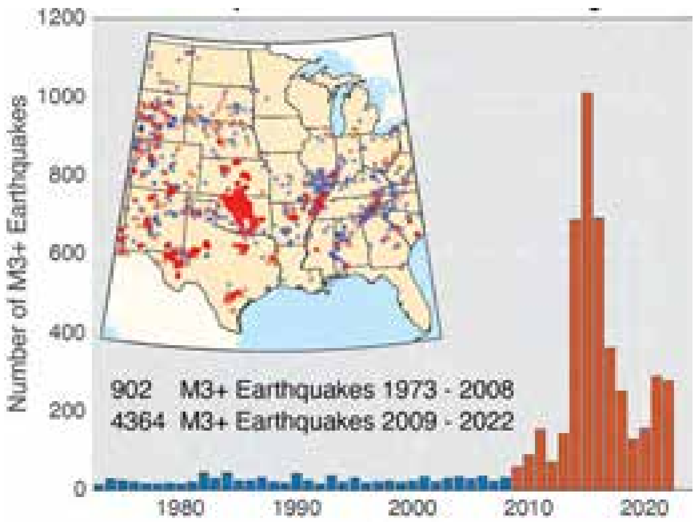
The seismicity rate in the central and eastern United States increased 40-fold from 2002 to 2012, predominantly as a result of human activities (Ellsworth, 2013; van der Baan and Calixto, 2017). This increase in seismicity rate in the central and eastern United States has largely been attributed to large-volume wastewater disposal wells injecting fluids into deep sedimentary formations (e.g., Keranen et al., 2014; Rubinstein and Mahani, 2015). Other human activities, including hydraulic fracturing (Skoumal, Brudzinski, and Currie, 2015) and carbon sequestration (e.g., Kaven et al., 2015), have induced seismicity to a lesser extent in the central and eastern United States (Skoumal et al., 2020).

Exhibit 5-1 presents the annual number of earthquakes (with a magnitude of 3.0 or larger) occurring in central and eastern areas of the United States for 1973–2022. Many of these earthquakes have taken place in areas where hydraulic fracturing has been and is actively occurring (e.g., Oklahoma) (USGS, 2022). Between 1973 and 2008, approximately 25

[y] Hydraulic fracturing involves injecting large volumes of fluids into the ground to release trapped oil and natural gas. Wastewater from oil and gas production, including shale gas production, is typically disposed of by being injected at relatively low pressures into extensive formations that are specifically targeted for their porosities and permeabilities to accept large volumes of fluid.

earthquakes of magnitude three or greater occurred on average annually. Since 2009, at least 58 earthquakes of this same size (magnitude of 3.0 or larger) have occurred annually, and at least 100 earthquakes of this same size have occurred annually since 2013. The annual number of earthquakes (with a magnitude of 3.0 or larger) peaked in 2015 when 1,010 magnitude 3+ earthquakes were recorded. Given their magnitude, most of these earthquakes are large enough to have been felt by people, yet not large enough to cause significant damage (USGS, 2022).

Exhibit 5-1. Earthquakes in the Central and Eastern U.S. 1973–2022



Source: USGS (2022)

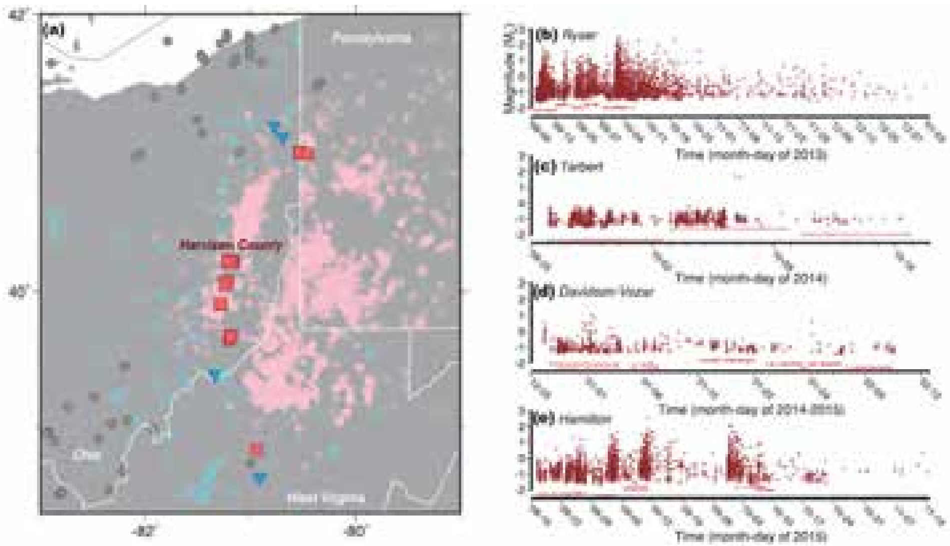
The following are examples of induced seismic events in the United States that have occurred in basins where unconventional natural gas production via hydraulic fracturing has occurred.

5.1.1 Utica and Marcellus Shales in the Appalachian Basin

The Appalachian Basin is currently the largest natural gas producing area in the United States The Marcellus and Point Pleasant Utica shale plays are both located in the Appalachian Basin and extend from New York to Kentucky. They each cover prospective areas of 190,000 and 220,000 km^2, with proven reserves of 135 and 24 Tcf of natural gas, and 345 and 210 MM barrels of oil, respectively (EIA, 2019b). Earthquakes detected in the basin as analyzed by Schultz et al. from 2013 to 2015 are presented in Exhibit 5-2.

The map on the left provides the location sequences of cataloged (magnitude > 2.0) seismic events in Ohio and neighboring states for 2010–2017. Blue triangles show earthquake sequences induced by wastewater disposal; red squares show earthquake sequences induced by hydraulic fracturing; and pink squares and blue triangles depict the horizontal and wastewater disposal wells that remain in the area. Grey circles represent earthquakes assumed to be occurring from natural causes. The four graphs on the right provide the temporal distribution of hydraulic fracturing induced seismic events for four wells in Harrison County, Ohio (Schultz et al., 2020).

Exhibit 5-2. Location and timing of induced and natural seismic events in the Appalachian Basin



Used with permission from Schultz et al. (2020)

5.1.2 Anadarko and Arkoma Basins of Oklahoma

Dramatic increases in seismic activity have been reported for areas in both central and northern Oklahoma, where the Anadarko and Arkoma Basins are located. Historically, an average of one to two ML[z] ≥ 3.0 earthquakes has occurred in Oklahoma annually. The number of ML ≥ 3.0 earthquakes occurring in the state, however, rose to over 900 in 2015 (Ellsworth, 2013).

While the seismicity rate began to decline in 2016, the yearly total seismic moment[aa] of Oklahoma remained high in response to three Mw[bb] ≥ 5.0 earthquakes occurring during the year, including the Pawnee earthquake, the largest earthquake (5.8 Mw) ever recorded for the state of Oklahoma. The seismicity rate increase has generally been attributed to the disposal of large volumes of produced water into the Arbuckle Group basin (Haffener, Chen, and Murray, 2018).

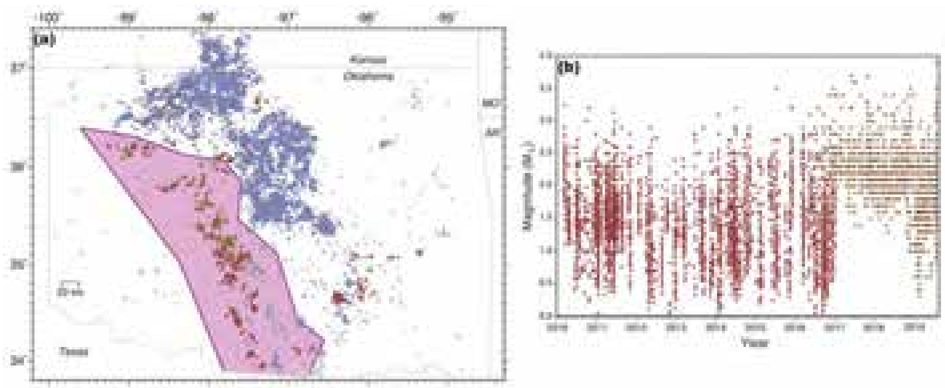
[z] ML refers to the magnitude on the Richter scale, where M stands for magnitude and L stands for local.

[aa] Seismic moment represents a measure of the size of an earthquake, depending on the area of rupture, the rigidity of the rock, and the amount of slip from faulting.

[bb] Mw is known as the moment magnitude of an earthquake. For very large earthquakes, moment magnitude gives the most reliable estimate of earthquake size.

Exhibit 5-3 shows the location (left) and magnitude (right) of induced seismic events in Oklahoma between 2010 and 2020. In the map on the left, seismic events from natural causes are represented by the blue circles, while induced seismic events are represented by the red (Skoumal et al., 2018) and orange circles (Shemeta, Brooks, and Lord, 2019). The graph on the right shows the number and magnitude of the induced seismic events over time (Skoumal et al., 2018; Shemeta, Brooks, and Lord, 2019).

Exhibit 5-3. Induced seismicity events in Oklahoma



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5.1.3 Fayetteville Formation in the Arkoma Basin of Arkansas

Following the success of the Barnett Shale (Fort Worth Basin, Texas), the Fayetteville Formation in Arkansas became an early target for continued shale gas development in the United States. This unconventional play runs east to west across north central Arkansas, extending across nearly 150 km. By 2005, horizontal well completions in the middle to lower organic rich facies at depths typically 1–2 km were coming online and, by 2009, 0.5 Tcf of gas was being produced per year (Browning et al., 2014).

The Fayetteville Formation has a history of seismicity that dates back to before the region was developed for oil and natural gas extraction. In September 2010, a series of seismic events reaching magnitudes close to 5.0 Mw on the Richter Scale occurred along the Guy-Greenbrier Fault within the basin. Not long after, on February 28, 2011, a 4.7 Mw earthquake—the largest ever recorded—occurred within the basin. This led to concerns that even larger earthquakes could potentially occur in the area, which resulted in an emergency shutdown order for any injections being put in place by the Arkansas Oil and Gas Commission. Analysis of the seismicity, injection patterns, and pore pressure diffusion built a strong case for the activation of the Guy-Greenbrier Fault by wastewater disposal (Horton, 2012; Ogwari, Horton, and Ausbrook, 2016; Ogwari and Horton, 2016; Park et al., 2020). In the neighboring states of Oklahoma and Texas, wastewater disposal by injection is understood to be the primary driver of induced seismicity.

5.1.4 Eagle Ford Shale Play in the Western Gulf Basin of Texas

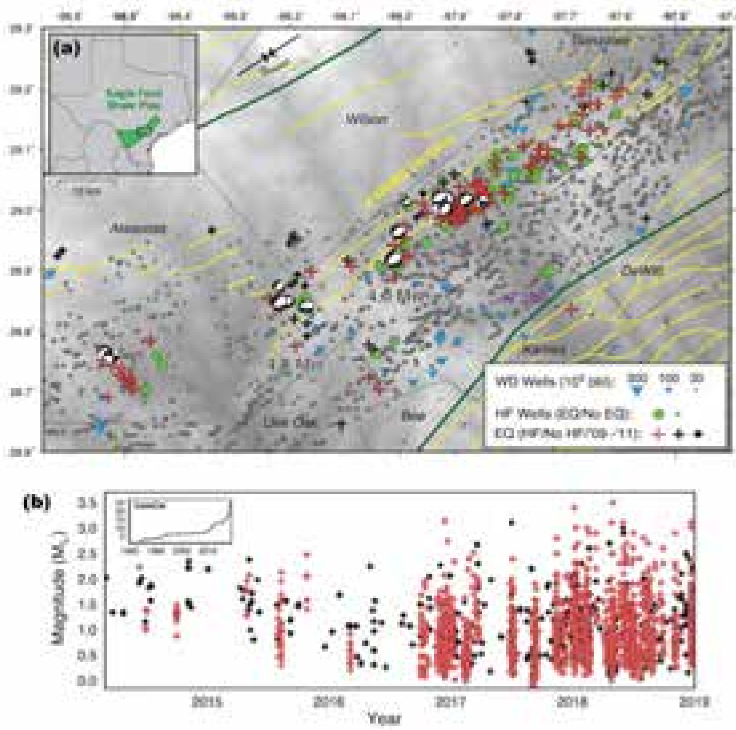
Texas has a long history of active oil and natural gas production, hydraulic fracturing, wastewater disposal, and general seismicity, some of which occurs within or near areas of pervasive faulting (see Exhibit 5-4a) (Ewing, 1990; Frohlich et al., 2016). Advancements in horizontal drilling and hydraulic fracturing since 2008 have prompted the Eagle Ford shale play to focus on hydrocarbon production from the Upper Cretaceous Eagle Ford and Austin Chalk Formations (Frohlich and Brunt, 2013; Martin et al., 2011; Pearson, 2012; RRC, 2019).

In 2018, the rate at which ML ≥ 3.0 earthquakes occurred in the Eagle Ford shale play was 33 times higher than background levels (3 earthquakes per 10 years during 1980–2010; see Exhibit 5-4b). Fasola et al. (2019) investigated seismicity that has occurred since 2014, in an effort to identify how hydraulic fracturing has contributed to seismicity within the play. Comparing both times and locations of hydraulic fracturing to a catalog of seismic activity, Fasola et al. (2019) suggest more than 85 percent of the seismicity that occurred was spatiotemporally correlated with hydraulic fracturing. More specifically, there were 94 ML ≥ 2.0 earthquakes correlated with 211 hydraulic fracturing well laterals.

Exhibit 5-4a provides a map from the Texas Seismological Network highlighting earthquakes (crosses) and focal mechanisms (beach balls) that have occurred since 2017. Hydraulic fracturing wells are indicated by black circles in Exhibit 5-4. Correlated earthquakes and hydraulic fracturing wells are displayed as red plus signs and green circles, respectively. Black diamonds show the earthquakes that occurred during 2009–2011 (Frohlich and Brunt, 2013). Purple square shows the seismic station (735B) used for template matching. Wastewater disposal wells are provided as teal triangles sized by median monthly volumes. Arrows show regional orientation (Lundstern and Zoback, 2016). Faults (Ewing, 1990) are in yellow.

Exhibit 5-4b provides the magnitudes of the various earthquakes both correlated and not correlated with hydraulic fracturing that occurred annually after 2011 within the play (the black and red plus signs shown in Exhibit 5-4a). The inset shows the cumulative number of earthquakes (magnitude ≥ 3.0) occurring in the area, available from the USGS Comprehensive Catalog.

Exhibit 5-4. Locations and timings of Eagle Ford hydraulic fracturing induced events



Used with permission from Schultz et al. (2020)

5.2 Induced Seismicity Research and Development

State regulators have long been focused on identifying the precise location and magnitude of earthquakes and determining their cause. When earthquakes can be linked to wastewater injection, regulators respond by ordering operators to cease or limit either injection rates and/or water volumes in nearby wells (EPA UIC National Technical Workgroup, 2015). Many regulators also require that new injection wells avoid areas near known active faults. In Oklahoma, these techniques have effectively reduced the number of felt earthquakes.

Similar procedures have been applied to hydraulic fracturing operations in some states. That is, when earthquakes are detected, operations are either modified or suspended (AGI, 2017). Oklahoma, Texas, and Ohio have all taken steps to mitigate induced seismicity linked to hydraulic fracturing.

In Texas, the state's Center for Integrated Seismicity Research (TexNet) is charged with monitoring, locating, and cataloging seismicity across the state. Capable of detecting and locating earthquakes with magnitudes ≥ 2.0, TexNet's backbone network improves investigations of ongoing sequences of seismic activity by deploying temporary seismic monitoring stations and conducting site-specific assessments (Young et al., 2017). TexNet continues to conduct fundamental and applied research to better understand both naturally and potentially induced seismic events that are occurring across the state of Texas, their associated risks, and potential strategies for communicating with stakeholders and responding to public concerns raised regarding seismicity (Young et al., 2017).

Through the DOE-funded RPSEA, University of Texas researchers analyzed data collected by the portable NSF EarthScope USArray program to evaluate seismic hazards in different oil and gas producing regions. Results show that regions need to be studied individually before crafting regulations for injection management strategies due to the following results:

- In the Barnett shale play region, earthquakes occur near high volume injection disposal wells.
- In the Eagle Ford play region, earthquakes are not near injection wells, but follow increases in extraction of water/petroleum.
- In the Bakken play region, there are high volume injection wells but almost no earthquakes.
- There were eight times as many earthquakes in the Fort Worth Basin as reported by the USGS during 2009–2011, based on data collected by the transportable USArray.

Also funded through RPSEA, the Oklahoma Geological Survey in collaboration with the University of Oklahoma, the Oklahoma Secretary of Energy and Environment, and industry have:

- Improved the accuracy of locating earthquakes by adding permanent and portable seismic monitoring stations, the data from which is publicly available through the Oklahoma Geologic Survey's Oklahoma Earthquake Catalog.
- Documented a major increase in salt-water disposal in areas within seismically active areas.
- Mapped previously unidentified basement faults in Oklahoma that are now publicly available in open file maps.
- Developed 4-D integrated models for risk assessment (Office of Oil and Natural Gas, 2016),

5.3 References

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6 LAND USE AND DEVELOPMENT

Land presents a critical yet often overlooked constraint to energy development, including the development of domestic natural gas. The growing land use footprint of energy development, termed “energy sprawl,” likely causes significant habitat loss and fragmentation with associated impacts to biodiversity and ecosystem services (McDonald et al., 2009). Natural gas is growing as a transition fuel during the grid decarbonization process in the United States, making an understanding of its land use implications a critical and necessary consideration (Dai et al. 2023).

Expanding energy development is now the primary source of anthropogenic land cover change in natural ecosystems in North America (Allred et al., 2015; Trainor, McDonald, and Fargione, 2016), including eastern deciduous forests, boreal forests, prairie grasslands, sagebrush-steppe, and deserts (Copeland, Pocewicz, Kiesecker, 2011; McClung and Moran, 2018; Appiah, Opio, Donnelly, 2019). Land use and development issues associated with natural gas production include local surface disturbance; cumulative landscape impacts; habitat fragmentation; and increased traffic, noise, and light.

The Citizens Marcellus Shale Coalition (CMSC) (2011) explored two issues related to impacts of shale gas production on public lands and the other industries that rely on these lands. They also explored impacts on private property rights. CMSC stated that shale gas development must consider the cumulative impacts on state parks and forests and on timber and tourism industries as part of ensuring responsible stewardship of public resources. Property rights and environmental degradation are a growing public concern, and eminent domain laws, drill spacing requirements, and grouping of leased lands could help protect these rights. These findings are still relevant to current natural gas extraction.

6.1 SURFACE DISTURBANCE AND LANDSCAPE IMPACTS

The infrastructure needed to support the supply chain of electricity produced from natural gas involves production sites (production pads and their access roads), transportation facilities (e.g., gathering and transmission pipelines for natural gas), processing facilities, and power plants (end-use) (Dai et al., 2023). Such activities can disturb the Earth’s surface, the impacts of which can extend over large areas and result in habitat fragmentation that impacts both plant and animal species. Mitigation options include adoption of best practices for site development and restoration, avoidance of sensitive areas, and minimization of impacts to disturbed areas.

Dai et al. (2023) used machine learning, remote sensing, and geographic information systems to obtain spatially explicit information on the land required to support natural gas production for use in power plants. Their analysis considered land use across five life cycle stages of natural gas produced for electricity production from wells (production stage), natural gas transportation via gathering pipelines (gathering stage), natural gas processing (processing stage), natural gas transportation via transmission pipelines (transmission stage), and gas consumption as fuel through combustion in gas-fired power plants (use stage).

For the production stage, Dai et al. (2023) mapped land-use for 100,009 wells located at 75,915 different well pads. Among the 100,009 wells examined, 31,716 were co-located. In non-

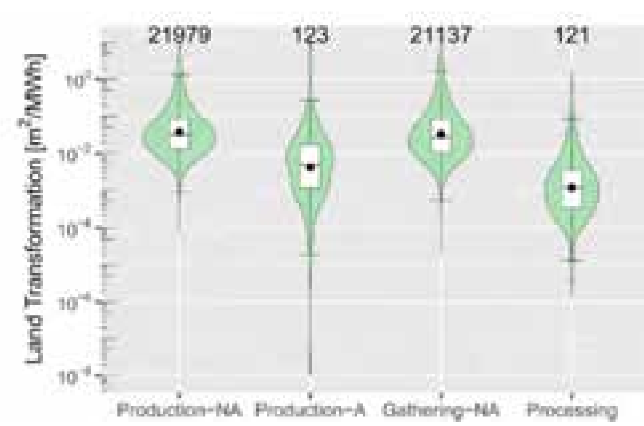
agricultural areas, results suggest vertical wells occupy ~4,000 square meters (m^2) less land per site than horizontal-/directional-drilled wells. During the gathering stage in both agricultural and non-agricultural areas, sites with horizontal-/directional-drilled wells require ~230 meters less pipeline in length on average than sites with vertically drilled wells. Whereas due to the requirement for larger width of right-of-way, the extent of land used is almost doubled for sites with horizontal-/directional-drilled wells than those with vertical wells. Results from Dai et al. (2023) are summarized in Exhibit 6-1.

Exhibit 6-1. Land use for the production, transportation, and processing of natural gas for use in gas-fired power plants

Stage			Unit	Average
Production	Agricultural	Directional	m^2 per site	9,346
		Vertical	m^2 per site	2,100
	Non-agricultural	Directional	m^2 per site	18,170
		Vertical	m^2 per site	14,090
Transportation by pipeline	Length	Directional	m^2 per site	597
		Vertical	m^2 per site	818
	Area	Directional	m^2 per site	20,157
		Vertical	m^2 per site	10,128
Processing			m^2 per (MM cubic feet per day)	4,318

Exhibit 6-2 from Dai et al. illustrates the land transformation by stage, finding that production in non-agricultural areas utilizes more land than agricultural areas.

Exhibit 6-2. Land transformation in natural gas production



Note: NA = non-agricultural area, A = agricultural area

Used with permission from Dai et al. (2023)

Notably, technological advancements will play a significant role in decreasing the amount of land that will be transformed during the life cycle stages of production, gathering, and consumption of natural gas—for both vertical and horizontal/directional wells. Directional drilling technology enables more than 20 wells to be drilled in a single pad, and each well could have a comparable amount of lifetime production. As a result, the total amount of production per site with directional-drilled wells can be an order of magnitude higher than the conventional sites with vertical drilled wells, which dramatically lowers the land transformation for production and gathering (Dai et al., 2023).

6.2 HABITAT FRAGMENTATION

The development of drilling sites for natural gas production can disrupt the habitat of both plant and animal species in several different ways. For example, habitat fragmentation can occur when infrastructure must be installed, or land clearing must take place to allow access to a well location. Land area that is occupied by well pads and the construction of pipelines are two of the leading causes of habitat fragmentation (Cooper, Stamford, and Azapagic, 2016; Langlois, Drohan, and Brittingham, 2017). The land area occupied for shale gas extraction typically can be reduced through the use of multi-well pads at one site, which have a surface footprint (and water use) per well two to four times lower than that of single-well pad sites (Manda et al., 2014).

The construction and installation of the infrastructure necessary for natural gas development can lead to a habitat being converted from a large contiguous patch of similar environments to several smaller, isolated environments. When contiguous core habitats are fragmented into smaller patches, many sensitive species are unable or unwilling to cross non-habitat regions to reach alternative habitat patches. While habitat loss can have an immediate impact on wildlife population, the ecological response to fragmentation is lagged, and affects different species at varying timescales (Makki et al., 2013).

A secondary impact of fragmentation is the creation of edges. Edges are generally defined as the 100 meters between core forest and non-forest habitat (PADEP, 2014; Kargbo, Wilhelm, and Campbell, 2010; Johnson et al., 2010). New edges affect the physical or biological conditions at the ecosystem boundary and within adjacent ecosystems (Fischer and Lindenmayer, 2007). Edge effects are believed to be detrimental by increasing predation, changing lighting and humidity, and increasing the presence of invasive species (Johnson et al., 2010).

Exhibit 6-3 provides a schematic depicting the habitat loss and fragmentation from natural gas production. Exhibit 6-3 progresses from infrastructure development that has quantifiable land impacts leading to temporally extended land changes—impacts that account for habitat loss and fragmentation.

Exhibit 6-3. General procedure for depicting land disturbance from natural gas extraction

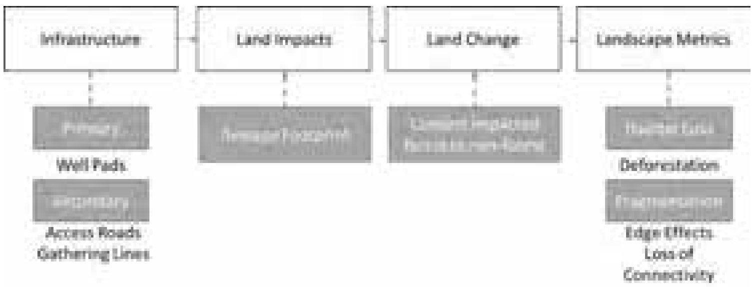
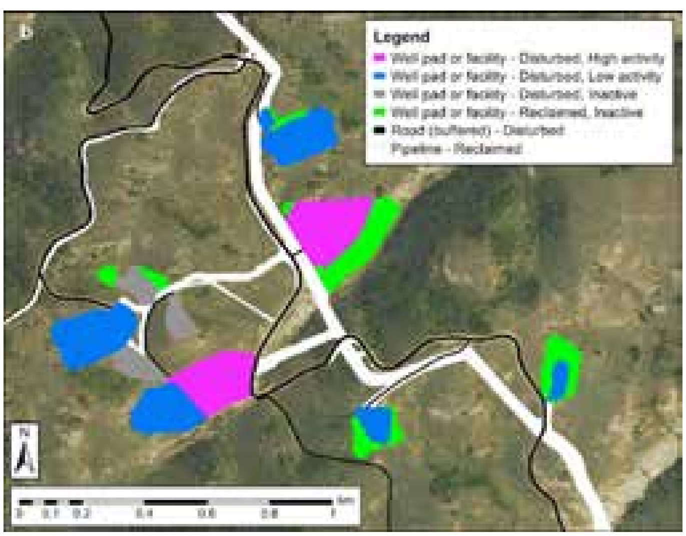


Exhibit 6-4 provides an example of energy infrastructure features digitized from 2013 National Agricultural Inventory Program satellite imagery overlaid with well locations reported in Colorado Oil and Gas Conservation Commission (COGCC) data. Each mapped feature (or portion thereof) was classified by type (well pad, facility, road, or pipeline) and by surface type (disturbed or reclaimed), and well pads and facilities (or portions thereof) were assigned an activity status (high, low, or inactive) (Walker et al., 2020).

Exhibit 6-4. Footprint of a well pad and surrounding infrastructure



Used with permission from Walker et al. (2020)

Each region where natural gas extraction takes place has unique species and habitat therein. Within those species, some are more greatly affected than others, whether it be core habitat fragmentation or edging.

Long-term effects of shale gas production on habitat disturbance will have to be evaluated as the development of these resources continues. Mitigation measures such as avoidance, best management practices, and prompt reclamation of the drilling site have been put forward as ways to best minimize the possible impacts that shale gas production may have on habitats. Habitat disruption can also result from a lack of surface water availability in response to withdrawals to support natural gas production and from erosion and chemical spills.[cc]

6.3 Noise, Light, and Traffic

Natural gas development processes are associated with both noise and light pollution, which can contribute to stress among those living in nearby communities (Down, Armes, Jackson, 2013; Korfmacher et al., 2013; Peduzzi et al., 2013; Witter et al., 2008a; Witter et al., 2008b). Construction, vehicles, drilling, compressors, flaring, and other processing equipment and facilities can all pollute by producing excessive noise and continuous illumination (Cleary, 2012).

6.3.1 Noise Pollution

A health impact assessment in Colorado identified noise pollution as an area of concern and noted that it occurs during drilling and completion operations, flaring, and because of vehicular traffic (Witter et al., 2013). Workers can be exposed to noise through many sources on site, including diesel engines, drilling, generators, mechanical brakes, heavy equipment operations, and radiator fans (Witter et al., 2014); therefore, hearing impairment is a noise-related health concern for workers on site.

A 2010 study using biomonitoring from Texas found residents reporting concerns about odors and noise apparently related to shale gas well and compressor station operations, although this was a separate, independent component from the biomonitoring portion designed to address residents' concerns (Texas Department of State Health Services, 2010). While the authors noted that it was difficult to determine if the levels were above acceptable limits that may be harmful to human health, and that noise may affect quality of life, this is speculative because noise levels were not measured to establish decibels of noise in the study area.

Noise standards for a single well pad may be met; however, the cumulative effects of multiple operations in one area might exceed these established decibel levels. In terms of setback distances, some noise regulations distinguish between maximum decibels for day and night, while others distinguish between maximum decibels for certain phases of the operation such as drilling, fracturing, and production; however, there is often variability and, in some areas, it is suggested that distances are set as monitoring points, not necessarily points indicative of being protective of health (Fry, 2013).

6.3.2 Light Pollution

Light pollution has significant implications for the environment and public health, and its effects have become more pronounced over time due to the increasing extent and radiance of artificially lit areas (Kyba, 2017). Substantial economic values have been attached to affected

[cc] The potential water use implications of natural gas are discussed in Chapter 4 – Water Use and Quality.

outcomes, such as biodiversity, recreation, and public health. With respect to human health, artificial lights at night are associated with sleep deprivation and mental health (Patel, 2019; Xiao, 2020); sleep deprivation, in turn, has been shown to reduce cognition and labor market productivity, as well as elevate mortality risks associated with dementia, heart attacks, and vehicle accidents (Hafner et al., 2017; Paksarian et al., 2020; Ma et al., 2020; Jin and Ziebarth, 2020; Prats-Uribe, Tobías, and Prieto-Alhambra, 2018.). A study in Australia quantified the financial and non-financial costs of inadequate sleep in 2016–2017 to be $45 B (Hillman et al., 2018) and another study estimates that $680 B is lost due to sleep deprivation across five Organisation for Economic Co-operation and Development (OECD) countries (Hafner et al., 2017; Boslett, 2021).

The impacts of light pollution also extend to human health and well-being. Artificial light disrupts melatonin secretion and circadian rhythm (Haim and Zubidat, 2015) with corresponding changes in mood regulation, depression, and sleeping disorders (Cho et al., 2016). Light pollution-driven changes in circadian rhythms may also have contributed to recent growth in obesity and metabolic dysfunction (Fonken et al., 2010). Growing laboratory and epidemiological evidence also support the long-hypothesized relationship between nighttime light exposure and cancer rates (Kerenyi, Pandula, and Feuer, 1990; Kloog, et al., 2010; Schwimmer et al. 2014; Jones, Pejchar, and Kiesecker, 2015).

Light pollution also has significant consequences for wildlife populations. It affects nighttime behavior and habits of terrestrial (Bennie et al., 2015) and marine (Davies et al., 2013) wildlife populations, particularly for species that use sunlight or moonlight for guidance. It disrupts natural sleep and reproductive cycles, geographical orientation, and predator-prey relationships (Longcore and Rich, 2004). Other effects of light pollution include changes in bird singing behavior (Miller, 2006), estrus patterns in nocturnal primates (LeTallec, Théry, and Perret, 2015), insect pollination (MacGregor et al., 2015), and fish biological rhythms (Brüning et al., 2015). These impacts have led to ecosystem-wide changes in biodiversity and growing disparities between entire taxonomic groups (Davies et al., 2013).

While there is some work speculating that light pollution associated with shale development induces psychosocial stress (Fisher et al., 2017), sleep and mental health issues (Casey et al., 2018), and adverse impacts to local ecosystems (Kiviat, 2013), the literature directly connecting the recent resource boom to light pollution is extremely limited. No work has documented the causal impact of U.S. shale development on light pollution.

6.3.3 Traffic

Traffic may increase in any given area because of unconventional natural gas development, but the magnitude of this increase has not been studied in depth. The phases of development that require the most traffic load involve well pad construction, drilling and well completion, and pipeline construction (Witter et al., 2014). It appears that changes in traffic patterns will be dependent upon the area and either the individual project or the cumulative effects of multiple projects in an area. Industrial truck traffic can be detrimental to health-related air quality due to vehicle exhaust, as well as pose an increased risk of motor vehicle crashes.

In the *Revised Draft Supplemental Generic Environmental Impact Statement on The Oil, Gas and Solution Mining Regulatory Program*, the New York State Department of Environmental Conservation (NYSDEC) identified temporary but adverse noise and visual impacts from construction activity and increased truck traffic among the potential land-use environmental impacts associated with natural gas production (Witter et al., 2014). Significant adverse impacts in terms of damage to local and state roads could also result. Among mitigation measures described for environmental impacts, NYSDEC suggests imposing measures to reduce the adverse noise and visual impacts from well construction. A transportation plan could also be required that would include proposed truck routes and assess road conditions along the proposed routes. Exhibit 6-5 tabulates the number of truck trips for a typical shale gas well (Massachusetts Institute of Technology [MIT], 2011).

Exhibit 6-5. Truck trips for a typical shale gas well drilling and completion

Activity	1 Rig, 1 Well	2 Rigs, 8 Wells
Pad and Road Construction	10–45	10–45
Drilling Rig	300	60
Drilling Fluid and Materials	25–50	200–400
Drilling Equipment (casing, drill pipe, etc.)	25–50	200–400
Completion Rig	15	30
Completion Fluid and Materials	10–20	80–160
Completion Equipment (pipe, wellhead, etc.)	5	10
Fracturing Equipment (pump trucks, tanks, etc.)	150–200	300–400
Fracture Water	400–600	3,200–4,800
Fracture Sand	20–25	160–200
Flowback Water Disposal	200–300	1,600–2,400
Total	**1,160–1,610**	**5,850–8,905**

The large volumes of water involved in hydraulic fracturing operations can create high volumes of road traffic given the majority of the water used for fracking is transported by truck. It should be noted that the large number of traffic movements shown in Exhibit 6-5 are worst-case estimates. In particular, re-use of flowback wastewater significantly reduces the amount of road traffic associated with hauling water, which represents much of the traffic movement. Furthermore, large-scale operators are also using pipelines to transport water to the site, substantially reducing the amount of road traffic (MIT, 2011).

The Eagle Ford Shale Task Force Report for the RRC identified increased traffic and deterioration of roads and bridges among the infrastructure impacts from shale gas development (Porter, 2013). Exhibit 6-6 lists estimates of the number of truck-trips-per-shale-gas-well in the Eagle Ford (Porter, 2013).

Exhibit 6-6. Loaded truck trips per gas well

Activity	Number of Loaded Trucks
Bring well into production	1,184
Maintain production (per year)	Up to 353
Re-fracturing (every 5 years)	997

These impacts are enough of a concern that the task force considered alternative financing methods to help meet the increased demands on roads and bridges (Porter, 2013).

Upadhyay and Bu (2010) surveyed the visual impacts of Marcellus drilling and production sites in Pennsylvania. They reviewed the drilling process, assessed direct visual impacts, and compared the results to the impacts of other technologies (e.g., windmills and cell towers). They also studied drill-pad density from map and aerial perspectives to examine the likelihood of seeing drill towers across a landscape, and the modeled potential impacts for increased drilling, making the following conclusions:

- Serious impacts from light and noise are a potential problem within a small radius of drilling sites.
- Indirect impacts like increased truck traffic, equipment storage, and temporary structures compose the most salient visual impacts, rather than the drill pads themselves.
- Timelines for site restoration of visual impacts vary significantly.

Upadhyay and Bu (2010) recommended that visual impacts be addressed during the siting and design phase and that nighttime impacts could be avoided by pointing lights downward.

The Resources for the Future (RFF) (2013) report also gave several options in their survey of experts under the category of community disruption. Included in this category, as well as in the habitat fragmentation section, were such risks as light pollution, noise pollution, odor, and road congestion. The industry respondents identified a number of these community disruptions as risk pathways of high priorities, while the other respondent groups identified more conventional (e.g., air pollution, water pollution) risks.

6.4 Reducing Potential Land Use Impacts

Linear infrastructure on private land contributed to the greatest loss of core forest. Unlike private land, the majority of pipelines on public land were collocated with roads, which likely reduced habitat fragmentation. Large public landowners can negotiate with a relatively small number of gas operators compared to private landowners (PADEP, 2016); therefore, individual landowners can make deals with different operators such that two different operators end up working in close proximity and duplicating infrastructure on private land rather than public land.

6.4.1 Mitigation Options for Habitat Fragmentation Impacts

Mitigation strategies related to pipelines enacted by state agencies have shown that fragmentation on public lands has been reduced more than on private lands, especially when multiple mitigation strategies are implemented on public land with the goal of reducing surface disturbance and impacts to forest. For example, the Pennsylvania Department of Conservation & Natural Resources (PADCNR) can limit the number of well pads per leased track (PADCNR, 2014). This method constrains development intensity (i.e., pad density) and encourages operators to increase the number of wells per pad, thereby maximizing per well drainage and efficiency (DOE, 2016). A widely implemented mitigation policy on state forest land requires gas infrastructure to utilize existing surface disturbance whenever feasible, including road networks, right-of-way corridors, or abandoned mine lands (PADCNR, 2014).

Similarly, Abrahams, Griffin, and Matthews (2015) found that requiring pipelines to follow existing roads prevented further fragmentation in a core forested region while allowing full extraction of the shale resource. Collocation is widely accepted as an effective mitigation strategy to reduce surface impacts (Bearer et al., 2012; Racicot et al., 2014); however, it rarely occurs on private land.

6.4.2 Reducing Light Pollution

Even two decades after the establishment of designated programs by non-governmental organizations to recognize and certify the quality of night skies and nighttime darkness resources, the very notion of what a “dark sky” is remains unsettled from a scientific standpoint (Crumey, 2014); while appropriate instrumentation can quantify night sky brightness, it cannot properly account for the human aesthetic experience of natural night. However, various lines of research increasingly suggest that unsafe thresholds of exposure to artificial light at night in terms of intensity, duration, wavelength, and timing likely exist for humans, plants, and animals. In this sense, light-sensing technologies applied in the field could effectively serve as “dosimeters” for monitoring these exposure parameters (Barentine, 2019).

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7 SOCIETAL CONSIDERATIONS FOR NATURAL GAS DEVELOPMENT

The production and transportation of natural gas in the United States, including natural gas imports and exports, carries implications to energy, environmental, and social justice. Understanding what these implications are and how they are being managed for disadvantaged communities (DACs) is a key component to ensuring prior injustices are not further perpetuated. As these communities have long been disproportionately exposed to the environmental risks and other types of harms that arise from these type activities while simultaneously relying on such activities to sustain their economies.

This chapter aims to 1) provide background on approaches to consider societal issues during energy project planning, which is directly transcribable to natural gas market operations; and 2) provide information on such approaches specific to DOE. As natural gas is projected to play a significant role during the current energy transition, this chapter discusses societal considerations and justice concepts within the context of large-scale energy infrastructure planning decisions designed to enable the United States to achieve its goal of net-zero emissions by 2050. The review begins with a discussion of energy justice, which includes a presentation of Spurlock et al.'s (2022) "Deep Decarbonization Framework," which aims to incorporate the three tenets of energy justice into energy infrastructure planning decisions.

The provision of information and potential guidance for ensuring a consideration of societal issues and justice during natural gas project planning is presented in terms of how DOE and some major energy companies are actively considering and incorporating justice-related concepts within their decision-making frameworks. This chapter specifically discusses how DOE is incorporating societal considerations and justice strategies as part of efforts to right historical wrongs, including a summary of tools DOE has made available to understand how investments are distributed to DACs, and how justice is being incorporated into strategic plans.

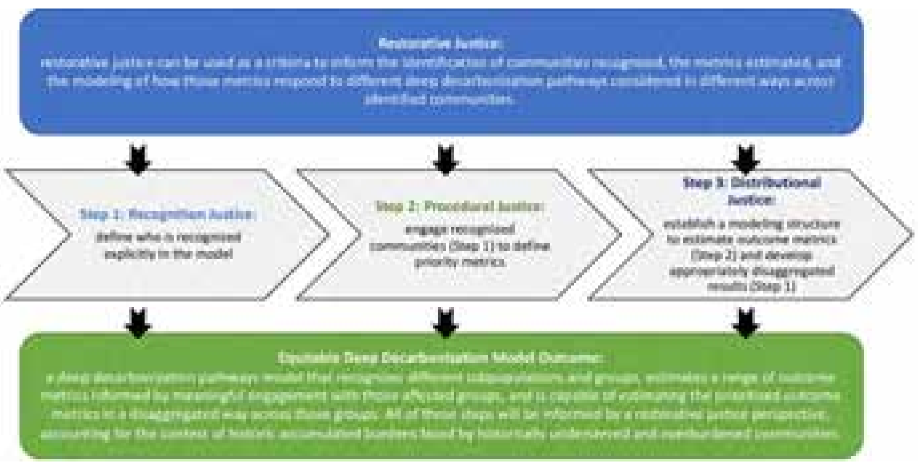
7.1 ENERGY JUSTICE

DOE defines energy justice as 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 who have historically been disproportionally harmed by the energy system (DOE, 2022b). Energy justice explicitly centers the concerns of communities—in particular those at the frontline of pollution and climate change, working class people, indigenous communities, and those historically disenfranchised by racial and social inequity (e.g., DACs) (Initiative for Energy Justice, 2023). A just energy system is one in which energy is accessible, affordable, clean, and democratically managed for all communities (Initiative for Energy Justice, 2023).

Qian et al. (2022) describe energy justice as focused on considering the fairness with which energy policies are implemented and other energy-related decisions are made. Using energy justice as a decision-making framework, Iwińska et al. (2021) outline the focus of this emerging area of literature as one that seeks to both understand and consider how the policy-making framework surrounding the production and consumption of energy resources can be fairer—for example, understanding how the implementation of a new energy policy designed to lower emissions would impact rates of energy poverty (i.e., percent of households who are unable to meet their energy needs) (Bednar and Reames, 2020).

Noting the need to consider how energy policies and other decisions (that are being designed to enable the U.S. to achieve its deep decarbonization targets) might perform in terms of their influence on justice, Spurlock et al. (2022) developed the "Equitable Deep Decarbonization Framework"—see Exhibit 7-1. Anchored in the core tenets of recognition, procedural and distributional justice (each discussed in the following sub-sections of this report) the framework represents an effort to create a shared language and enable meaningful collaboration between scholars and practitioners of energy justice and modelers of decarbonization.

Exhibit 7-1. Flow of energy justice decisions



Used with permission from Spurlock, Elmallah, and Reames, 2022

7.1.1 Recognition Justice

At its core, recognition justice deals with respect and consideration. Spurlock et al. (2022) present the concept as a demand to recognize that divergent views exist on how policymakers can best address issues of energy justice. Those views reflect the unique, diverse backgrounds of individual communities, and that their perspectives and opinions reflect their unique histories. Incorporating those voices in the energy transition is critical to ensuring policymakers implement project development that seeks to serve all. Equitable outcomes begin with the recognition that disenfranchised communities must be re-enfranchised and re-empowered to ensure their histories and perspectives are heard in a meaningful way.

7.1.2 Procedural Justice

Spurlock et al. (2022) present procedural justice as essentially the effort to include all voices. This is the idea that DACs are overburdened and underserved, and their disenfranchisement can only be corrected when their voices are intentionally included in the start-to-finish process of advancing project and policy development. In other words, stakeholder engagement must be done early and often to ensure the priorities of DACs are of primary focus as the priorities of the project or policy.

7.1.3 Distributional Justice

Distributional justice is focused primarily on both the equitable and inequitable distribution of benefits across communities (Spurlock et al., 2022). It is a concept focused on the well-being of individuals, which spans the gambit of human outcomes such as psychological well-being, societal well-being, and physiological well-being (Deutsch, 1975). Distributional justice delves into the question of which matters more—equity or equality—and where need might dominate when identifying unjust distributions.

Fairness is a key concept within distributional justice and can be characterized as a problem for geospatial analysis (Bouzarovski and Simcock, 2017). Across the energy supply chain, distributional justice is a problem of implied risk responsibility as well as costs and benefits (Heffron and McCauley, 2014). In addition to inequities created by a historical lack of inclusiveness is the risk that those structural deficits will compound under a changing climate. In other words, unless addressed, the deficits of the past will likely increase as the climate changes—much like a revolving line of credit tends to grow faster over time when a balance is carried from one period to the next.

7.2 JUST ENERGY TRANSITIONS

The current energy transition presents a generational opportunity to make significant progress in ameliorating historical injustices (Wang and Lo, 2021). As technology has evolved and capital has flowed into large-scale energy infrastructure investments, a concerted effort to accrue the economic and social benefits associated with these technologies and investments in DACs may prove fruitful in spurring a more just outcome from the energy transition. Equally possible is the ability to start mitigating the systemic injustices that have plagued these same communities in response to historical decision-making.

This is not always as clearcut as it might seem. For example, the wholesale shift toward and then away from natural gas use is harmful to communities reliant upon energy industry revenues—especially when local governments tie public services and infrastructure investments to these revenues (Haggerty et al., 2018). Fully considering the need to balance an energy transition with preserving local government functionality requires a goal-setting process that includes these nuanced considerations.

Articulation of these goals can be achieved by addressing a handful of broad topics including poverty reduction (Lo and Broto, 2019; Koehn, 2008; Colenbrander et al., 2017), amelioration of historical energy injustices (Jasanoff, 2018; Delina and Sovacool, 2018; Carley and Konisky, 2020), and opportunities for economic growth (Yang, Cao, and Lo, 2018; Ehresman and Okereke, 2015). Wang and Lo (2021) argue that the energy transition is an apt vehicle for fixing historical wrongs if it can simultaneously account for environmental costs DACs already suffer from; the reality that climate change will likely exacerbate these pre-existing environmental costs; and for a decision-making process steeped in the tenets of assuring energy justice.

Moving forward into a new energy landscape that is sustainable requires policymakers to try and avoid repeating historical injustices—emphasizing the need to empower communities through efforts like Community Benefits Plans and Agreements with justice frameworks (the bedrock of transition planning) (Wang and Lo, 2021; Williams and Doyon, 2019). Pai, Harrison, and Zerriffi (2020) provide the framework for researchers to consider strategies to preserve the well-being of fossil-fuel-reliant communities that are at risk of large, sudden population losses when the primary industry disappears. Preserving the human capital of these communities is a critical goal for ensuring the energy transition policy provides opportunities for all. Pai, Harrison, and Zerriffi (2020) summarize more than a dozen requirements that would facilitate policymaker efforts to ensure a just transition, but they underscore one: the requirement of intentional effort for long-term planning with routine efforts to conscientiously engage with affected communities.

7.2.1 Community Benefits Plans

A community benefits plan is one of the requirements for funding requests that fall under the Biden-Harris Administration's Justice40 initiative, which was mandated under Executive Order 14008 and has the explicit goal that 40 percent of the overall benefits from certain federal investments flow to DACs (DOE, 2023a).[dd] A community benefits plan serves as a guide for how a proposed project is likely to benefit a community and its members. Guided by four core policy priorities when incorporated comprehensively into a project proposal—and fully executed—a community benefits plan helps to ensure justice (DOE, 2022a; 2023a):

1. Meaningfully engaging communities and labor
2. Investing in America's workforce
3. Advancing diversity, equity, inclusion, and accessibility
4. Implementing an environmental justice plan

A central component of the community benefits plan is actively engaging with communities, both prior to and following the commencement of an investment, permitting the identification of potential but not yet realized (i.e., a priori) and actual realized positive and negative impacts to DACs. Strong community benefits plans are based on preliminary needs assessments performed for comminates and include some type of measurable performance indicator.

Guided by the Justice40 initiative, FECM created specific planning guidance for fostering community inclusion in the planning process for the research that it funds, which includes large energy infrastructure projects. The guidance promotes inclusive and sustainable outcomes that reflect community visions around stakeholder engagement with communities and tribes; details diversity, equity, inclusion, and accessibility plans; and explicitly focuses on Justice40 goals, alongside the creation of quality jobs (FECM, 2022a; 2022b). This includes a clearly defined

[dd] Covered investments include those related to the clean energy transition both in energy production and the advancement of net-zero emission transportation, including affordable housing and "green" workforce development and training, as well as those focused on remediation of legacy pollution, clean water initiatives, and wastewater projects.

framework for engagement that prioritizes meaningful two-way communication (FECM, 2022c) and the development of a community benefits plan (DOE, 2022a).

7.2.2 Fossil Fuel Employment and Revenue

One aspect of ensuring a just energy transition for the United States is the management of unemployment in fossil-fuel related industries—including industries that produce and consume natural gas. There is an associated risk that pivoting away from fossil fuel resources too quickly removes employment opportunities in regions that have long relied on these industries for economic support (i.e., where these industries have provided the bulk of available jobs and have historically been the core driver of local economic growth). Fossil fuel-related jobs losses can result in a significant loss to local government revenues, long-term declines in the economy, and a potential cycle of population loss from which a region is unable to recover.

In many regions of the United States where fossil fuel industries have historically dominated, unions are mobilizing to "ensure that the transition to a clean energy economy keeps workers at the center—all the while benefitting the greater communities in which they live" (Department of Labor, 2023). Unions are viewed as invaluable structures for elevating and empowering the voices of DACs in the energy transition (Pai, Harrison, and Zerriffi, 2020; Newell and Mulvaney, 2013). Energy industries have a high unionization rate (Pai and Carr-Wilson, 2018) making them a practical vehicle for members to advocate for their communities and achieve a just transition[ee] (Stevis and Felli, 2015). Directly approaching unions as potential enablers of cooperation with communities can help avoid rupturing communities through the kinds of mass, unplanned job loss that exacerbates population flight.

Often, mass job loss leads to dying communities characterized by broad negative health and social impacts. Intentional efforts to diversify local economies would increase the resilience of local economies (Lobao et al., 2016). Notably, increasing the diversity of local economies is a positive as it introduces a greater resilience and broad, regional growth (Freudenburg and Gramling, 1994).

Among the opportunities a just transition presents is the ability to reduce the gender gap in regions dominated by the fossil fuel industry, increase investment into local energy infrastructure, remediate historical environmental damage, retrain the local workforce to "skill up" the region's human capital, and shore up local government revenues through economic diversification (Pai, Harrison, and Zerriffi, 2020).

In the end, just transitions are achieved when local voices are not just heard but amplified during the energy transition process. This starts when governance strategies acknowledge the dignity of DACs and groups and engage those communities and groups in less divisive governance strategies (Grossmann and Trubina, 2021).

[ee] The term "just transition" originated within community-organizing efforts centered on labor unions (Eisenberg, 2018).

7.3 Energy Governance and Adaptive Management

Governance structures play a vital role in transitioning away from a carbon-intensive economy, but the ability of these structures to provide an equitable or just transition is not guaranteed (Moss, 2009). Incorporating the concept of just outcomes begins with the governance structures of energy project development and planning (Newell and Mulvaney, 2013). Those who are in the position of governance are in a position of authority to achieve more equitable outcomes to benefit disadvantaged populations (Florini and Sovacool, 2009).

As Florini and Sovacool (2009) point out, governance is not simply government. Governance is an activity in which governments participate, but governance provides the framework that aligns the goals of government and intergovernmental organizations, while incorporating the needs of the private sector market participants and communities to collectively manage a process that ideally serves all groups. Even companies steeped in natural gas and oil industries recognize their responsibility to contribute to the transition and have established their own net-zero commitments and plans that need to be considered in broader energy governance strategies. A Baker Hughes's (2022) report outlined their efforts to meet company Diversity, Equity, and Inclusion goals; successes in reducing their own greenhouse gas emissions profile by 23 percent as compared to 2019 levels, and their $492 MM commercial innovation efforts in clean energy technologies such as hydrogen and carbon capture and storage (Baker Hughes, 2021).

Governance is necessary given two issues with which economists often wrestle. One issue is that society is not capable of ensuring equitable access to public goods and services without some overarching set of rules to facilitate that outcome and a governance structure to underpin such requirements and drive implementation. Another issue is that any economic or social activity tends to create what economists call “externalities.” That is, there are unintended results that can occur indirectly from the consumption of goods, provision of services, or other social interactions stemming from these activities.

The decommissioning of a coal power plant is a prime example of the need for governance to protect the public’s well-being from externalities, as an idle power plant could become the source of negative health outcomes for a community without intentional efforts to prevent such outcomes. Governance structures are necessary to deal with these two conceptual issues because there is no economic incentive to do so otherwise (Florini and Sovacool, 2009).

Perspectives can clearly vary within communities and that variation can affect governance structures (Wang and Lo, 2021). Community engagement is important, but it is not the magic elixir that solves the problem by itself. Ciplet and Harrison (2019) identify three conflicts that emerge in the effort to facilitate an energy transition: 1) between inclusivity and sustainability where inclusive processes that invite community engagement require more time to complete projects; 2) between sustainability and the need to recognize the unique value system for each community, which increases the complexity of sustainability goal pursuits; and 3) between equity and sustainability, meaning that the distribution of costs and benefits can conflict with or possibly detract from project performance.

In short, the lack of consideration for energy justice issues within the global framework of energy governance will likely perpetuate historical disadvantages within communities (Symons and Friederich, 2022). This is a function of existing power structures within current governance frameworks. Beyond that, Symons and Friederich (2022) show that the political sovereignty of communities making independent decisions over energy project development will always result in outcomes that serve each group's self-interest and ignore the related externality problems. Without intentional adjustments to governance that deal with these structural problems, the current paradigm will continue to create winners and losers and perpetuate the current disenfranchisement of some communities and the diverse stakeholders living and working there.

Good governance strategies for energy project development require support from the government, reliable capital and operational funding, diversification goals for the economy, and diverse coalitions (Wang and Lo, 2021; Cha, Wander, and Pastor, 2020). Finally, the creation of ownership stake opportunities at the onset of project development for DACs is critical to ensuring that the tradeoffs between disenfranchised communities and the regional benefits of energy projects ameliorate losses. Greater rates of acceptance have been found to exist within communities with larger ownership stakes in energy projects (Hogan et al., 2022).

7.4 JUSTICE CONSIDERATIONS FOR NATURAL GAS

Natural gas will remain a key player in meeting energy demand throughout the energy transition. However, there is increased focus on justice concerns; particularly with energy development, it is crucial to recognize both the opportunities and challenges that natural gas production and related activities present.

While justice-minded concerns for natural gas production and related activities is an emerging area of research, the environmental effects of these activities on communities have been the subject of significant study and government regulation. As discussed in the preceding chapters, natural gas industrial activities can impact local air and water quality. For example, natural gas flaring has the potential to harm the health of both humans and animals, yielding flaring a significant justice-related matter concerning the distribution of risks, benefits and harms, and recognition of rights for communities where activity occurs (Aigbe, Cotton, and Stringer, 2023).

Additionally, hydraulic fracturing and injection of water for disposal purposes can induce seismic activities that impact local communities. Communities are also impacted by land use for natural gas industrial activities. In addition to preventing other uses of land, these activities can cause noise and light pollution.

There have also been studies of the local economic impacts of natural gas development. These studies found that the long-term impact of natural gas market expansion has been muted in terms of population growth. Communities that struggled with population loss or benefited from population gains prior to the expansion of activity tended to demonstrate the same patterns even after the initial bump from natural gas expansion, though many communities found the composition of their communities skewed more toward younger men as a result of natural gas investments (Jacquet, et al., 2018). Longitudinal studies focused on younger, rural Pennsylvania youths in the Marcellus Shale region reported these persons were more optimistic expectations for their futures as a result of the boom in natural gas activity; while older adults presented more mixed opinions as they tend to consider the impacts beyond job opportunities such as increased traffic, higher rents, and generally a higher cost of living as a result of the temporary influx of people (McLaughlin et al., 2017).

The disparate concerns over natural gas project development within communities presents an opportunity to empower locals. Empowering these communities to monitor socioeconomic impacts of technologies similar to hydraulic fracturing have had somewhat unintended consequences overseas. By engaging communities in monitoring efforts, these projects bring them together in a way that empowers their voices, increases their participation in the planning process, and results in more benefits accruing within community households than when the community is excluded. This requires intentionality, consistency, and follow-through on the part of policymakers to ensure community voices have the platform to share their concerns (Haggerty and McBride, 2016). Broadly speaking, the provision of strong monitoring systems to preserve air quality and environment are key to enabling communities to trust that projects are authentically invested in the protection of household safety and security (DOE, 2022d).

Broad research into how private industry gains acceptance to engage in natural gas project development illustrates the importance of social justice in project developers' approach to the community. Across forty interviews held in Wyoming, Walsh and Haggerty (2020) revealed landowners and stakeholders largely pointed to the need for project development approaches to be rooted in procedural fairness, the demonstration of respect for communities needs and choices, as well as a fundamental sense of trust.

While only around 13 percent of U.S. natural gas production occurs on federal lands, leases for oil and gas production on federal lands are administered by DOI are subject to review under NEPA that requires review for environmental impacts as they pertain to the human environment (NEPA, 2023).[ff]

7.5 Department of Energy Initiatives with Justice Components

DOE has long been an active participant in efforts to ameliorate the negative impacts of legacy emissions and pollution while facilitating the pivot toward a more sustainable energy future. DOE's effort includes several programmatic responses where DOE plays a leading role in administrating change such as the Undocumented Orphan Wells program to target emissions and pollution from historical fossil fuel impacts on communities, as well as the Methane Mitigation Program, which focuses on today's use of fossil fuels. In addition, many of DOE's existing programs fall under covered programs within the Biden/Harris Administration's Justice40 Initiative. Beyond this, DOE is actively building out the capacity of the broader public to measure the state of disadvantage at the community level through the development of its Climate and Economic Justice Screening Tool.

[ff] 13 percent is based on a reported estimate of natural gas production from federal lands of 4,882,439.827 MM cubic feet in 2022 from Office of Natural Resources Revenue (ONNR) and a value of 43,385,576 MM cubic feet for total U.S. natural gas marketed production in 2022 from EIA (ONNR, 2023; EIA, 2023).

7.5.1 Justice40 Initiative-Covered Programs

DOE has over 140 programs covered under the Biden/Harris Administration's Justice40 Initiative. Demonstrating the department's long-standing commitment to equity and social justice, many of these programs are decades-old efforts to ameliorate impacts of DACs across seven areas covered by the Justice40 Initiative (DOE, 2023a). That includes programs targeting climate change, sustainable and affordable housing, the remediation and reduction of legacy pollution, development of clean water and wastewater infrastructure, workforce development and training, development and preservation of sustainable and affordable housing, and cleaner transit options, as well as clean energy and energy efficiency (DOE, 2021).

DOE prioritizes social justice across myriad programs that focus on outcome-specific programs such as workforce development and holistic, process-oriented organizing efforts. Under DOE's Office of Economic Impact and Diversity, the Minority Education, Workforce Development, and Training Program supports small businesses, institutions that serve minorities explicitly, and nonprofits with grants targeting science, technology, engineering, and mathematics educational opportunities; strategic capacity building; general workforce development; and assistance in technical issues. From a holistic perspective, DOE initiated the Domestic Engagement Framework under FECM as an organizing structure to facilitate cohesive community engagement across stakeholders and tribes in an effort to deploy clean technologies. Built from a five-part series of engagement principles, the framework prioritizes two-way engagement, proactive engagement early in the process, place-based engagement, community-based knowledge, and the concerted effort to build out the capacity for community engagement (FECM, 2022a; 2022b).

In deploying holistic frameworks to outcome-specific programs, DOE sets out a process-oriented mission within targeted efforts to foster the ability for communities to lead alongside federal agencies toward more equitable outcomes.

7.5.2 Undocumented Orphan Wells Program

Under the Infrastructure Investment and Jobs Act of 2020, DOE was mandated with the directive to facilitate a targeted push to accelerate the energy transition. Within this package, DOE was charged with administering $4.7 B under the Undocumented Orphan Wells Program to plug, remediate, and reclaim orphaned wells.

Orphaned wells are oil or gas wells that were formerly productive in the nonrenewable extraction industry, but whose ownership status became unclear or nonexistent after operations ceased. In most cases, the firm with historical ownership of the wells no longer exists due to bankruptcy or the abandonment of the well occurred so long ago that ownership responsibilities could not be determined. As such, there is no readily identifiable entity or person with the responsibility to maintain the closure of the well in a manner that prevents the leakage of methane, hydrocarbons, or other miscellaneous chemicals and toxins that tend to pollute the surrounding areas, harm wildlife, increase the likelihood of disease in nearby communities, and/or reduce the economic development and overall prosperity within the affected areas.

The exact number of wells is unknown, though current estimates of 300,000–800,000 wells implies the magnitude of potential impacts from orphan wells is significant (Interstate Oil and Gas Compact Commission, 2021). Coordinating across a handful of other federal agencies, lower-level governments, the Interstate Oil and Gas Compact Commission, and Indian Tribes, DOE created a research consortium at five national laboratories to find and characterize orphaned wells across the nation (DOE, 2022c).

7.5.3 Methane Mitigation Program

Originally known as the Resource Technologies and Sustainability Program, DOE operates the Methane Mitigation Program under FECM. This program targets the non-trivial levels of methane emissions that emanate across the oil and gas value chain of current usage. This includes emissions produced in the upstream production of methane, emitted in the midstream processing efforts, produced in the transportation of methane, and escaping during the end-use consumption of oil and natural gas.

The primary goals of this program focus on preventing emissions across the value chain via data collection and processing efforts. Direct and remote emissions sensor technologies are deployed to identify leakage at its source. Data generated from this collection process is then passed through a data collection pipeline to then facilitate the funding of research and analytics. Altogether, from upstream activities to midstream delivery, these efforts are oriented toward quantifying the size of emissions at their point source in order to serve the detection, measurement, and mitigation of emission leakages across the value chain of fossil fuel consumption. The ultimate goal of this program is to minimize the harm of legacy systems of fossil fuel use necessary for the energy transition by prioritizing efficient, cost-reducing technologies while maximizing the value added during the transition (FECM, 2021).

7.5.4 Energy Justice Tools

DOE has initiated comprehensive programmatic strategies to ameliorate historical injustices and implemented big-picture frameworks to guide organizing efforts across these programs in a manner that empowers communities as partners. As part of these efforts, DOE's Office of Economic Impact and Diversity's Office of Energy Justice Policy and Analysis have invested in the development and maintenance of multiple public-facing tools that can be used to illustrate and evaluate questions, policies, regulations, and practices with respect to energy and justice (DOE, 2023b).

One such tool is the Energy Justice Dashboard (BETA), which can be used assess the proportion of federally funded underwriting of projects that provide benefits to DACs. This data visualization tool seeks to measure the distribution of benefits to historically underserved and overburdened communities. Built from EPA's EJSCREEN tool, the BETA tool identifies the proportion of burden from pollution and public health risks accrued at the census-tract level. By leveraging data to measure historical disadvantage, this tool helps support DOE to assess data-driven outcomes from its programmatic efforts to right the injustices that have plagued so many communities.

DOE has identified and measured the disadvantage of roughly 27,251 communities at the census-tract level using this tool. The deployment of tools such as BETA during the energy transition is key, particularly during the early planning stages, in creating the desired approach for community outreach and in the effort to structure governance strategies. Identifying where DACs are provides the high-level understanding into where deficits in outreach and inclusion have likely exacerbated the pervasiveness of disadvantage (DOE, 2023b). FERC, which has authority over the siting of onshore LNG terminals and interstate natural gas pipelines, established the Office of Public Participation specifically to empower, promote, and support public voices in infrastructure decisions made at FERC (FERC, 2023).

DOE has also developed a new Energy Justice Mapping Tool for Schools that builds on DOE's original Energy Justice Mapping Tool. This new tool is intended to allow users to explore and produce reports for a specific school facility, which include but are not limited to the following metrics: 1) whether the school is located in a DAC, 2) whether it is in a rural location, 3) whether it is designated as a community shelter, 4) the percentage of students who are eligible to receive free and reduced priced meals, and 5) whether the school qualifies for Title I Schoolwide programming. Beyond its Energy Justice Dashboard (BETA), DOE is also currently developing the Energy Justice Mapping Tool - Disadvantaged Communities Reporter, which when operational will allow users to explore and produce reports on census tracts identified as DACs (DOE, 2023b).

7.6 Industry Initiatives

Some U.S. oil and gas trade associations have developed initiatives to promote energy justice principles. For example, API and its member companies have publicly committed to safe and responsible operations related to the discovery, production, and delivery of energy resources including natural gas (API, 2023). Noting that justice considerations intersect directly with U.S. natural gas industry operations, given the impact these operations have on people's lives and communities, API has focused on actions that respect human rights, engage stakeholders, improve performance, and create local economic opportunities (API, 2023).

A significant portion of the collective efforts of its member companies have revolved around being a good neighbor and having a positive impact in local communities. Member companies including Chevron, Conoco Phillips, and Cheniere Energy have announced that they have implemented industry practices to foster broad stakeholder engagement during every phase of a project's development and operation (API, 2023). Companies including Plains, Marathon Petroleum, and Chevron have invested in apprenticeship programs; science, technology, engineering, and mathematics education; and local youth programs. API has also established Community Engagement Guidelines to promote the safe and responsible development of natural gas resources in communities where member companies operate.

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Response to Comments for
ENVIRONMENTAL IMPACTS AND SOCIAL CONSIDERATIONS ASSOCIATED WITH UNCONVENTIONAL NATURAL GAS: 8.30.2023

Comment Number	Reviewer	Comment	Resolution
1	Tom Curry	Note revised title.	Adjusted to environmental impacts and societal considerations.
2	Tom C.	Source: Office of Pipeline Safety | PHMSA (dot.gov)	Added citation. (DOT 2018)
3	Tom C.	Thanks for leaving the comment. I understand the point but don't want to get into calculating intensities here.	Noted. Removed comment.
4	Tom C.	I'm confused - are we referencing the forthcoming publication or the previous one? I appreciate Scott's offer to update. We need to see what is available when we get a publication date for this report.	Reference is to NETL 2023 (NETL homepage for LCA). If the updated report is released we can include a footnote explaining the potential differences in the numbers but for now we have left it as is.
5	Tom C.	This is fine to keep.	Left in.
6	Tom C.	I don't think this is necessary and might be confusing since the graphic includes power generation using the gas. If we need this information, we can refer to the 2019 LNG study directly as it is part of the docket for the regulatory program.	Removed.
7	Tom C.	The studies here are not only production studies - I don't think the subheader is needed, the information connects to the previous section.	Removed.
8	Tom C.	13% based on natural gas production from Federal lands of 4,882,439.827 mmcf in 2022 from ONNR (https://revenuedata.doi.gov/query-data?dataType=Production) and a value of 43,385,576 mmcf for total U.S. natural gas marketed production in 2022 from EIA (Natural Gas Marketed Production (eia.gov)).	Added two citations and footnote with information
9	Tom C.	The National Environmental Policy Act (NEPA) applies to the execution of many of the Department of Interior's responsibilities with the goal of ensuring that information regarding environmental impacts is available to decision makers and the public before decisions are made. National Environmental Policy Act (NEPA) | U.S. Department of the Interior (doi.gov)	Added citation.
10	Tom C.	Reference: Office of Public Participation (OPP) | Federal Energy Regulatory Commission (ferc.gov)	Added citation.
11	Tom C.	The other chapters end with actions and R&D.	Section 7.5 provides a discussion of the DOE initiatives with justice components so we decided to exclude an additional section on R&D. Ch. 5 and Ch. 6 do not end with R&D so this may help with consistency.

From: Harker Steele, Amanda J.
Sent: Fri, 21 Jul 2023 19:51:59 +0000
To: Curry, Thomas; Skone, Timothy; Sweeney, Amy; Easley, Kevin
Cc: Robert Wallace; hartesingh@deloitte.com; Adder, Justin (NETL); Francisco De La Chesnaye
Subject: LNG Regulatory Analysis FWP - Task 4 Deliverable
Attachments: Draft_Env.Review_Task4_LNG_LNGRegAnalysisSupport_FWP-DraftPreDecisional_7_21_23.docx, Meeting Notes and Presentations_7_21.zip

Hi Tom, Amy, Tim, and Kevin,

*DRAFT*DELIBERATIVE*PRE-DECISIONAL*

Please find the revised draft of the update to the 2014 Addendum to the Environmental Review attached. We look forward to receiving your feedback and appreciate you allowing us the opportunity to improve the original draft.

I have also attached a .zip folder that contains notes from and slides presented during the meetings we had today.

I will be on travel next week but am reachable by email and in-person if you are in the D.C. area. I will be there for a conference.

I hope you all have a nice weekend!

Sincerely,

Amanda J. Harker Steele, Ph.D. (she/her)
Research Economist – EMAT, SSAE
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NATIONAL ENERGY TECHNOLOGY LABORATORY

POTENTIAL ENVIRONMENTAL IMPACTS ASSOCIATED WITH UNCONVENTIONAL NATURAL GAS

July 21, 2023

DOE/NETL-2023/4388

DRAFT DELIBERATIVE PRE-DECISIONAL

INTERNAL USE ONLY – NOT YET APPROVED FOR PUBLIC RELEASE

Disclaimer

POTENTIAL ENVIRONMENTAL IMPACTS ASSOCIATED WITH UNCONVENTIONAL NATURAL GAS

Hartej Singh[2]*: Writing – Original Draft;* ***Michael Marquis***[2]*: Writing – Original Draft;* ***Odysseus Bostick***[2]*: Writing – Original Draft;* ***Robert Wallace***[2]*: Writing – Original Draft;* ***Amanda Harker Steele***[1]*: *Writing – Review & Editing, Supervision*

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The authors wish to acknowledge the excellent guidance, contributions, and cooperation of the NETL staff, particularly:

Commented [HSAJ1]: Comment for FE/HQ: We will update accordingly for final draft to reflect contributions.

Suggested Citation:
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TABLE OF CONTENTS

LIST OF EXHIBITS

ACRONYMS AND ABBREVIATIONS

AEO	Annual Energy Outlook
API	American Petroleum Institute
AR5	IPCC Fifth Assessment Report
B	Billion
Bcf	Billion cubic feet
BLM	Bureau of Land Management
BTEX	Benzene, toluene, ethylbenzene, xylenes
Btu	British thermal unit
CBM	Coalbed methane
CH_4	Methane
CMSC	Citizens Marcellus Shale Coalition
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_2e, CO_2-eq	Carbon dioxide equivalent
COGCC	Colorado Oil and Gas Conservation Commission
CRS	Congressional Research Service
d	Day
DOE	Department of Energy
DOI	Department of the Interior
EIA	Energy Information Administration
EDP	Exploration, development, and production
EPA	Environmental Protection Agency
FECM	Office of Fossil Energy and Carbon Management
FERC	Federal Energy Regulatory Commission
FP	Flowback and produced (water)
ft, FT	Foot
g	Gram
G&B	Gathering and boosting
gal	Gallon
GAO	Government Accountability Office
GHG	Greenhouse gas
GHGI	Greenhouse Gas Inventory
GHGRP	Greenhouse Gas Reporting Program
GWP	Global warming potential
H_2S	Hydrogen sulfide
HAP	Hazardous air pollutant
HPh	Horsepower-hour
IPCC	Intergovernmental Panel on Climate Change
kg	Kilogram
kJ	Kilojoule
km	Kilometer
km^2	Square kilometers
kWh	Kilowatt hour
LCA	Life cycle analysis
LNG	Liquefied natural gas
m^2	Square meter
m^3	Cubic meter
Mcf, MCF	Thousand cubic feet
min	Minute
MIT	Massachusetts Institute of Technology
MJ	Megajoule
MM	Million
MWh	Megawatt hour
N_2O	Nitrous oxide
NEIC	National Earthquake Information Center
NETL	National Energy Technology Laboratory
NGL	Natural gas liquid
NOAA	National Oceanic and Atmospheric Administration
NORM	Naturally occurring radioactive material
NOx	Nitrogen oxides
NPS	National Park Service
NSPS	New Source Performance Standards
NYSDEC	New York State Department of Environmental Conservation
O_2	Oxygen
OAC	Ohio Administrative Code
ONE Future	Our Nation's Energy Future
ORC	Ohio Revised Code
OSF	Oral slope factor
PA	Pennsylvania

PADEP	Pennsylvania Department of Environmental Protection
PM	Particulate matter
PRV	Pressure release valve
REC	Reduced emission completion
RFF	Resources for the Future
RfV	Reference value
RRC	Railroad Commission of Texas
scf	Standard cubic foot
SDWA	Safe Drinking Water Act
SF_6	Sulfur hexafluoride
SO_2	Sulfur dioxide
T	Trillion
T-D, T&D	Transmission and distribution
T&S	Transport and storage
Tcf	Trillion cubic feet
tCO_2	tonnes carbon dioxide
TexNet	Texas' Center for Integrated Seismicity Research
t NG	tonnes natural gas
Tg	Teragram
tonne	Metric ton
U.S.	United States
UIC	Underground Injection Control
USFS	U.S. Forest Service
USGS	U.S. Geological Survey
VOC	Volatile organic compound
WV	West Virginia
yr	Year

1 INTRODUCTION

The United States (U.S.) Department of Energy's (DOE) Natural Gas Regulatory Program is responsible for granting authorizations to import and/or export natural gas from and/or to foreign countries. An important dimension of considering whether to grant such authorizations is how the additional natural gas production and transport activities needed to support these exports and/or imports may impact the environment. As such, these impacts are factors affecting the public's interest.

Although fundamental uncertainties exist regarding the exact amount of natural gas production or transportation that would occur in response to additional authorizations being granted, it is important that DOE acknowledge and provide the public with access to updated information regarding the potential environmental consequences associated with such activities. Accordingly, DOE has prepared this update to the 2014 Addendum to Environmental Review Documents Concerning Exports of Natural Gas from the United States (hereafter the 2014 Addendum) to provide the public with an improved understanding of the potential environmental impacts associated with such activities (DOE, 2014).

We cannot estimate with certainty where, when, or by what method any additional natural gas would be produced, consumed, or exported in response to the granting of authorizations to import and/or export natural gas. Therefore, DOE cannot meaningfully analyze the specific environmental impacts associated with such activities. As such, similar to the 2014 Addendum, this report provides only a review of the profusion of peer-reviewed, scientific literature produced related to the potential environmental consequences of expanding natural gas production and related activities.

As unconventional natural gas production has represented an ever-growing share of U.S. natural gas production, the environmental impacts reviewed in this report relate primarily to those associated with unconventional production activities. The publications referenced build on a strong body of existing literature that traces the evolution of unconventional natural gas production techniques from their conceptual stages in the 1970s, to the technology advancements that contributed to the shale gas boom of the early 2000s and further development of additional unconventional resources, including tight gas sands and coalbed methane (CBM) resources to the export of liquefied natural gas (LNG).

This report makes every attempt to summarize the published descriptions of the potential environmental impacts of unconventional natural gas upstream operations within the lower 48 states as detailed by government, industry, academia, scientific, non-governmental, and citizen organizations. The sources cited are all publicly available documents. While this report by no means represents an exhaustive list of the sources that discuss environmental consequences of upstream natural gas activities, the sources cited are assumed to be representative, and no significant areas have been excluded from the report. Multiple publications on similar topics are compared based only on their technical and methodological distinctions. No opinion on or endorsement of these works is intended or implied.

Commented [LBD2]: Suggest consider "may" and similar language that reflects uncertainties about impacts.

Commented [LBD3]: "such activities" near the end of this passage, at least textually as written, refers to "both conventional and unconventional natural gas markets" earlier in the passage. Suggest clarify to focus on unconventional, which is the topic of this report.

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Commented [LBD5]: Can something be said like that the authors believe this survey is representative and no significant areas have been excluded from this review?

Commented [HSAJ6R5]: Done

This report is divided into chapters, each of which contains a separate section of references so that each type of environmental impact can be explored further. The types of environmental impacts that are documented in this review include the following:

- Greenhouse gas (GHG) emissions and climate change (Chapter 2)
- Air quality (Chapter 3)
- Water use and quality (Chapter 4)
- Induced seismicity (Chapter 5)
- Land use and development (Chapter 6)
- Environmental and social justice (Chapter 7)

In addition to containing information on potential environmental impacts, this report provides some background information on domestic natural gas production.

1.1 Natural Gas Basics

Natural gas is an odorless, gaseous mixture of hydrocarbons, largely made up of methane (CH_4) but also containing small amounts of natural gas liquids (NGLs) and nonhydrocarbon gases (e.g., carbon dioxide [CO_2] and water vapor) (EIA, 2023b). Natural gas is one of the major combustion fuels used throughout the country. It is mainly used to generate industrial and utility electric power, produce industrial process steam and heat, and heat residential and commercial spaces. The average gross heating value of natural gas is approximately 1,020 British thermal units per standard cubic foot (Btu/scf), usually varying from 950 to 1,050 Btu/scf.

Natural gas is typically classified as being either conventional or unconventional depending on the permeability of the formation within which it is found, the production technology used to secure it, the current economic environment, and the scale, frequency, and duration of production from the resource (EIA, 2023b; Krieg, 2018).

Generally, conventional natural gas refers to natural gas found in highly permeable reservoirs, typically composed of sandstone or limestone, which allows for extraction to be completed in a relatively straightforward manner via vertical rather than horizontal drilling. Unconventional natural gas refers to natural gas found within low-permeable reservoirs; it is generally trapped within the pores (i.e., small, unconnected spaces) of rocks, which makes extraction more difficult (BP, 2017).

Innovations in existing oil and gas exploration and production technologies have revolutionized unconventional natural gas production in the United States. Unconventional natural gas resources not only make up for declining conventional natural gas production but have also contributed to an increase in the use of natural gas for power generation, manufacturing transportation, and residential and commercial heating, as well as the amount of natural gas

Commented [LBD7]: Should increasing exports be mentioned here, for completeness?

Commented [HSAJ8R7]: Adjusted

being exported from the United States. There are three primary types of unconventional natural gas:[a]

- **Shale Gas:** refers to natural gas found within shale rock formations, which consist of fine-grained sedimentary rock that forms when silt and clay-size mineral particles are compacted together (Zendehboudi and Bahadori, 2017). Shale rock formations can be easily broken into thinner, parallel layers of rock. Black shale, a dark-colored type of sedimentary shale rock containing organic-rich material, is also a source rock for unconventional natural gas (Ohkouchi, Kuroda, and Taira, 2015).
- **CBM:** refers to natural gas that is both generated and stored in coal beds. Originally extracted from coal mines to reduce the potential for explosions caused by an excess of CH_4 gas within the mine and subsequently disposed of, CBM now serves as an important source of energy. Sequestering CBM from deeper, denser coal formations often requires the use of hydraulic fracturing technology.
- **Tight Sands Gas:** refers to natural gas found in low-permeability, gas-bearing, fine-grained sandstones, or carbonates.

Shale rock formations contain significant accumulations of natural gas and/or oil. These formations are often referred to as “plays” and can be found in nearly 30 U.S. states. The Barnett Shale formation, which is located in Texas, has been producing unconventional natural gas since the early 2000s (RRC, 2023). It is one of the largest onshore natural gas fields in the United States. While the Barnett Shale formation still produces a significant amount of unconventional natural gas, the Marcellus Shale formation—located in the Appalachian Region of the United States and spanning Ohio, Pennsylvania, and West Virginia—is currently the largest producer of unconventional natural gas from shale (EIA, 2023b).

Primary enabling technologies for accessing unconventional natural gas include hydraulic fracturing and horizontal drilling. Hydraulic fracturing (sometimes referred to as hydrofracking or simply fracking) is the process of pumping water mixed with a small amount of sand and other chemical additives (i.e., fracturing fluid) underground through a wellbore at a pressure that is sufficient to cause a target rock formation to break (i.e., fracture) (USGS, 2019).[b] As the rock is fractured, natural gas that would have otherwise remained trapped is able to be released into a wellbore and returned to the surface (USGS, 2019).

The Internal pressure caused by the fracturing of the rock formation also releases fluid, which travels to the surface through the wellbore. This fluid is commonly referred to as “flowback” or “produced water” and may contain the injected chemicals in addition to any naturally occurring materials found below the surface (e.g., brines, metals, radionuclides, and hydrocarbons). The

[a] There are other types of unconventional natural gas whose exploitation has not yet reached commercial scale. These include methane hydrate, which is a crystalline solid that consists of a methane molecule surrounded by a cage of interlocking water molecules. Methane hydrate is an "ice" that only occurs naturally in subsurface deposits where temperature and pressure conditions are favorable for its formation.

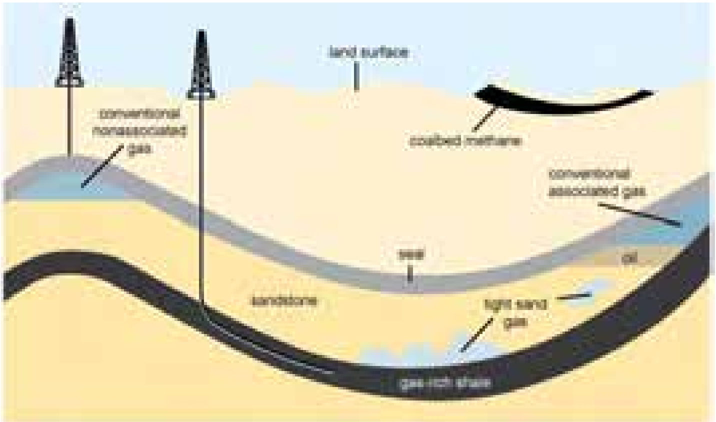
[b] The specific types of chemical additives used, and the proportions of each, depend on the type of rock formation that is being fractured. Additives function as friction reducers, biocides, oxygen (O_2) scavengers, stabilizers, and acids, all of which are necessary to optimize production. The composition of these fluids and the purposes of the additives are described in more detail in Chapter 4 – Water Use and Quality.

fluid is typically stored on site in tanks or pits before it is treated and disposed of or recycled. In many cases, disposing of the fluid involves injecting it underground. In areas where underground injection is not an option, the fluid can either be reused or processed by a wastewater treatment facility and subsequently discharged into surface water.

Hydraulic fracturing has been applied since the late 1940s when Standard Oil of Indiana (later known as Amoco) developed the technique and performed some of the first fracture treatments in the Hugoton Gas Field in Kansas (BP, 2017). While the use of hydraulic fracturing is not limited only to wells that are horizontally drilled, the combination of horizontal drilling and hydraulic fracturing has increased the volume of domestic natural gas considered to be "technically recoverable" (i.e., able to be produced using currently available technology and industry practices regardless of any economic considerations).

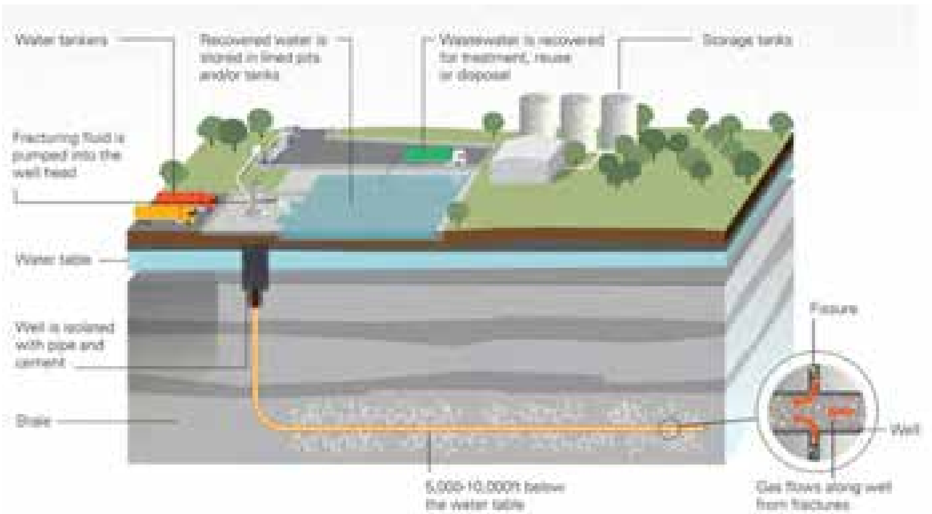
The process of horizontal drilling involves first drilling a vertical well. Once a certain depth has been reached with the vertical well, the path of drilling is bent until the well begins to extend horizontally. Horizontal wells are not only longer than vertical wells, but the process is much more complex. As such, a horizontal well is generally more expensive to drill than a vertical well, but it is expected to produce more natural gas (EIA, 2018). The horizontal or directional section of a well can extend thousands of feet (ft). Exhibit 1-1 provides a schematic of conventional natural gas and the various types of unconventional natural gas resources described previously (EIA, 2023b). Exhibit 1-2 provides a schematic of the hydraulic fracturing process (BP, 2017).

Exhibit 1-1. Schematic geology of natural gas resources



Source: Energy Information Administration (EIA 2023b)

Exhibit 1-2. Schematic geology of natural gas resources (3D)



Permission pending from BP (2017)

1.1.1 Liquefied Natural Gas

LNG is natural gas that has been cooled to a liquid state (i.e., cooled to about -260° Fahrenheit). The volume of natural gas in a liquid state is about 600 times smaller than the volume of natural gas in a gaseous state. Liquification of natural gas makes it possible to transport natural gas to places where pipelines currently do not exist or current pipeline infrastructure is unable to reach (e.g., abroad). Liquefying natural gas is one way to allow markets that are far away from production regions to access natural gas. Once in liquid form, natural gas can be shipped to terminals around the world via tankers. At these terminals, the LNG is returned to its gaseous state and transported by pipeline to distribution companies, industrial consumers, and power plants (DOE, 2021).

1.2 U.S. NATURAL GAS RESOURCES

Annual U.S. production of dry natural gas was approximately equal to 35.81 trillion cubic feet (Tcf) in 2022 (an average of about 98.11 billion cubic feet [Bcf] per day). Production has mostly increased year over year since 2005 as hydraulic fracturing combined with horizontal drilling of shale, sandstone, carbonate, and other geologic formations has continued. About 70.4 percent of domestic dry natural gas production in 2021 was supplied by 5 of the United States's 34 natural gas-producing states. States with a percentage share of total U.S. dry natural gas production in 2021 include Texas (24.6 percent), Pennsylvania (21.8 percent), Louisiana (9.9 percent), West Virginia (7.4 percent), and Oklahoma (6.7%) (Exhibit 1-3) (EIA, 2023b).

Exhibit 1-3. U.S. natural gas production by state in 2021

Source: EIA (2023b)

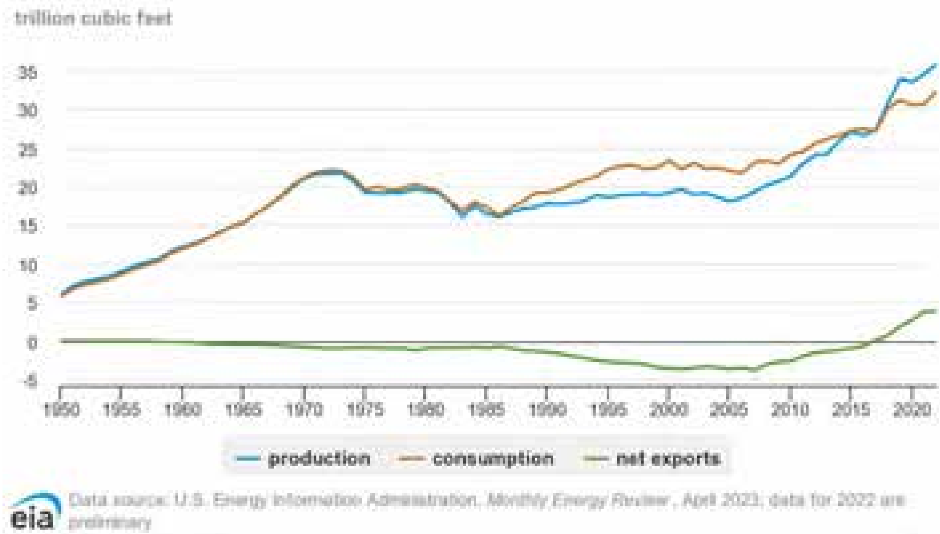
In 2022, production from coalbeds accounted for about 2 percent of U.S. dry natural gas production, and supplemental gaseous fuels accounted for about 0.2 percent. Supplemental gaseous fuels include biogas (sometimes called renewable natural gas), synthetic natural gas, and other gases. Although most of the natural gas wells operated by the United States are located onshore, some wells are drilled offshore (i.e., into the ocean floor in waters off the coast of the United States). In 2022, offshore dry natural gas production was approximately equal to 0.80 Tcf, accounting for about 2.3 percent of total production. The majority—87.6 percent—of this production occurred in federally managed waters within the Gulf of Mexico (EIA, 2023c).

In addition to being a producer of natural gas, the United States is also a consumer and net exporter of natural gas. In 2022, the United States produced about 10.8 percent more natural gas than it consumed. While there was sufficient domestic production to meet our consumption requirements, the United States did import some natural gas; not enough, however, to no longer be considered a net exporter. Exhibit 1-4 highlights recent (2022) and historical (1950–2021) U.S. natural gas production, consumption, and net exports (EIA, 2023c).

Commented [HSAJ9]: Notes/Questions for FE-HQ:

1. State-Level production data is not yet available for 2022 from the EIA. Do you prefer we remove this figure?

Exhibit 1-4. U.S. natural gas consumption, dry production, and net exports (1950–2022)



Source: EIA (2023c)

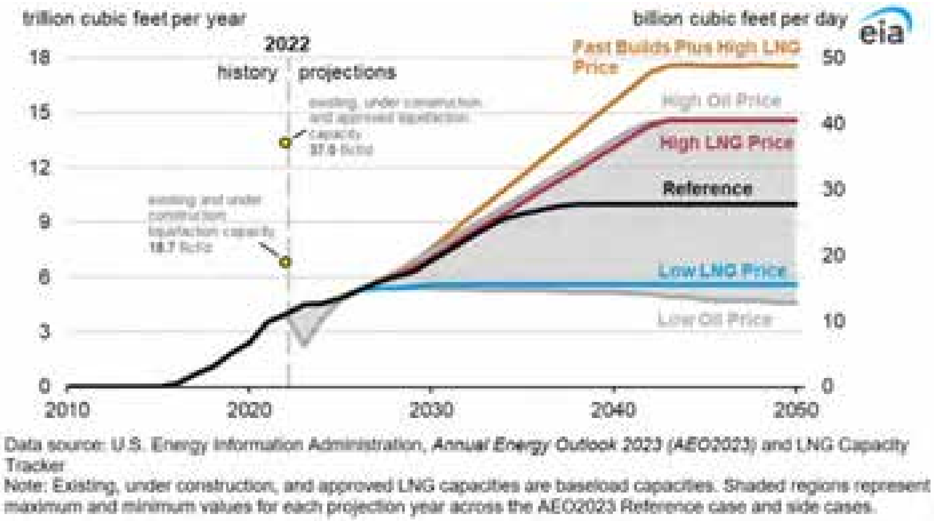
According to EIA's Annual Energy Outlook 2023 (AEO2023) reference scenario, domestic natural gas consumption is projected to decrease slightly but remain relatively constant out to 2050. Domestic natural gas production is projected to increase slightly and then also remain relatively constant out to 2050; see Exhibit 1-5 (EIA, 2023a).

Exhibit 1-5. Natural gas consumption and dry production projections through 2050

Source: EIA (2023a)

The AEO2023 reference scenario also projects that exports of natural gas, primarily LNG, will continue to increase between now and around 2035 (see Exhibit 1-6).

Exhibit 1-6. U.S. LNG export projections through 2050



Source: EIA (2023a)

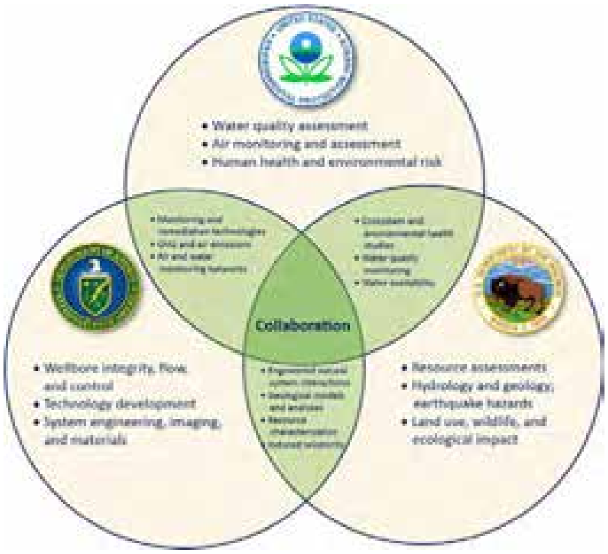
1.3 U.S. Regulatory Framework and Federal Research and Development Programs

The following sub-sections provide a review of both federal and state regulatory responsibilities related to the production, transportation, use, and export of domestic natural gas resources.

1.3.1 Federal

Multiple federal agencies have authority over the production of unconventional natural gas resources. Three of these agencies—DOE, the Department of the Interior (DOI), and the Environmental Protection Agency (EPA)—play a critical role as they are charged with monitoring, assessing, and reporting on various environmental impacts both associated and not associated with natural gas production. Exhibit 1-7 describes the roles and responsibilities of these three agencies in more detail in addition to the way these agencies work together to inform policy-relevant science.

Exhibit 1-7. Key U.S. agencies and their roles in natural gas development and production



Source: DOE

EPA is in charge of regulating underground injection and disposing of wastewater resources and other liquids covered under the Safe Drinking Water Act (SDWA). They are also charged with regulating the air emissions covered under the Clean Air Act.

Federal agencies including EPA, DOI's Bureau of Land Management (BLM), the National Park Service (NPS), the Occupational Safety and Health Administration, and the U.S. Forest Service (USFS) are responsible for enforcing regulations for unconventional natural gas wells drilled on public lands. BLM is responsible for ensuring the environment of these lands remains protected and unaffected by natural gas production and other related activities.

USFS and BLM are both responsible for managing natural gas development on federally owned lands. Natural gas production and other related activities that will or do take place within the boundaries of our nation's national parks are the responsibility of NPS, which establishes regulations to protect park resources and visitor values. Exhibit 1-8 provides some examples of federal statutes that apply to unconventional natural gas development.

Exhibit 1-8. Selected federal regulations that apply to unconventional oil and gas development

Statutes	Applicability
Clean Air Act	Places requirements on air emissions from sources of emissions at well sites; addresses compliance with existing and new air regulations, often delegated to local and state agencies. Generally, there is no distinction made between conventional and unconventional wells under the Clean Air Act.
Comprehensive Environmental Response, Compensation, and Liability Act	Only applies if hazardous substances besides crude oil or natural gas are released in quantities that require reporting. Natural gas releases do not require notification under the Comprehensive Environmental Response, Compensation, and Liability Act, but other hazardous substances may be released in reportable quantities during natural gas production.
Clean Water Act	Limits pollutants on produced water discharge under the National Pollutant Discharge Elimination System; stormwater runoff containing sediment that would cause a water-quality violation requires a permit under Clean Water Act decisions. Beneficial uses of surface waters are protected under Section 303.
Emergency Planning and Community Right-to-Know Act	Requires facilities storing hazardous chemicals above the threshold to report same and provide a Material Safety Data Sheet to officials and fire departments.
Endangered Species Act	Prohibits federal agencies from taking any action that is likely to jeopardize the continued existence of any endangered or threatened species (listed species) or result in the destruction or adverse modification of such species' designated critical habitat (Section 7); prohibits the taking of a listed species (Section 9); allows the Fish and Wildlife Service and National Marine Fisheries Service to issue a permit, accompanied by an approved habitat conservation plan, that allows for the incidental, non-purposeful "take" of a listed species under their jurisdictions (Section 10).
National Environmental Policy Act	Requires analysis of potential environmental impacts of proposed federal actions, such as approvals for exploration and production on federal lands.
Oil Pollution Act	Identifies spill prevention requirements, reporting obligations, and response planning (measures that will be implemented in the case of release of oil or other hazardous substances).
Resource Conservation and Recovery Act	Addresses non-hazardous solid wastes under Subtitle D. The Solid Waste Disposal Act exempts many wastes produced during the development of natural gas resources, including drilling fluids and produced water. EPA has determined that other federal and state regulations are more effective at protecting health and the environment.
Safe Drinking Water Act	Prevents the injection of liquid waste into underground drinking water sources through the Underground Injection Control (UIC) program. Fluids other than diesel fuel do not require a UIC permit. The UIC program gives requirements for siting, construction, operation, closure, and financial responsibility. Forty states control their own UIC programs.

1.3.1.1 Bureau of Land Management

BLM manages the U.S. government's onshore subsurface mineral estate, an area of about 700 million (MM) acres held jointly by BLM, USFS, and other federal agencies and surface owners.

Natural gas produced from the U.S. government's onshore subsurface mineral estate represents a significant portion of our nation's energy mix. In fiscal year 2022, sales of oil, gas, and natural gas liquids produced from the U.S. government's onshore subsurface mineral estate accounted for approximately 11 percent of all oil and 9 percent of all natural gas produced in the United States. About 23 MM acres had been leased to natural gas developers by the end of that year, and about 12.4 MM of those acres were producing natural gas in economic quantities (BLM, 2023). BLM published a rule regulating fracking on public lands on March 26, 2015—this rule was rescinded on December 28, 2017 (Fitterman, 2021).

1.3.1.2 Environmental Protection Agency

EPA's New Source Performance Standards (NSPS) set the regulations for emissions sources from the oil and natural gas sector. Exhibit 1-9 illustrates the scope of NSPS established to-date and the way regulations have evolved in scope since 2012 (EPA, 2021).

Commented [SW10]: Suggest spelling this out again at the beginning of each section.

Also, this needs to be updated to reflect the latest regulations.

Exhibit 1-9. Natural gas sources covered by EPA's proposed NSPS and Emissions Guidelines, by site

Location and Equipment or Process Covered	Required to or Would be Required to Reduce Emissions under EPA Rules (if finalized as proposed)	Rules that Apply			
		2012 NSPS for VOCs (OOOO)	2016 NSPS for Methane & VOCs (OOOOa)	2021 Proposed NSPS for Methane & VOCs (OOOOb)	2021 Proposed Emissions Guidelines for Methane (OOOOc)
Oil and Natural Gas Well Sites					
Completions of hydraulically fractured wells	✓	•	•	•	
Compressors at centralized tank batteries	✓			•	•
Fugitive emissions	✓		•	•	•
Liquids unloading	✓			•	
Pneumatic controllers	✓	•	•	•	•
Pneumatic pumps	✓		•	•	•
Storage vessels	✓	•	•[2]	•	•
Sweetening units	✓	•[1]	•[1]	•[1]	•[1]
Associated gas from oil wells	✓			•	•
Natural Gas Gathering and Boosting Compressor Stations					
Compressors	✓	•	•	•	•
Fugitive emissions	✓		•	•	•
Pneumatic controllers	✓	•	•	•	•
Pneumatic pumps	✓			•	•
Storage vessels	✓	•	•[2]	•	•
Sweetening units	✓	•[1]	•[1]	•	•
Natural Gas Processing Segment					
Compressors	✓	•	•	•	•
Fugitive emissions	✓	•		•	•
Pneumatic controllers	✓	•	•	•	•
Pneumatic pumps	✓		•	•	•
Storage vessels	✓	•	•	•	•
Sweetening units	✓	•[1]	•[1]	•	•
Transmission and Storage Segment					
Compressors	✓		•	•	•
Fugitive emissions	✓		•	•	•
Pneumatic controllers	✓		•	•	•
Pneumatic pumps	✓			•	•
Storage vessels	✓	•	•	•	•

[1]Covered for SO_2 only; [2]Covered for VOCs only

Source: EPA

EPA's Greenhouse Gas Reporting Program (GHGRP) requires GHG emissions data and other relevant information to be reported by large sources of emissions including fuel and industrial gas suppliers and CO_2 injection sites (EPA, 2023). The data reported is available to businesses, stakeholders, and other persons interested in tracking and comparing the GHG emissions of facilities, identifying opportunities to reduce emissions, minimizing wasted energy, and saving money. States, cities, and communities can also use EPA's GHG data to identify high-emitting facilities in their areas, compare emissions between similar facilities, and develop common-sense climate policies for constituents. The petroleum and natural gas industry is covered under

Subpart W of EPA's GHGRP. Unconventional natural gas production is covered under the provisions for onshore production, natural gas processing, natural gas transmission, and LNG storage and import/export. Annual CO_2, CH_4, and nitrogen oxides (NOx) emissions must be reported separately for each of these segments.

EPA studied the relationship between hydraulic fracturing for oil and natural gas and drinking water resources (EPA, 2022a). The study includes a review of published literature, analysis of existing data, scenario evaluation and modeling, laboratory studies, and case studies. EPA released a progress report in December 2012, a final draft assessment report for peer review and comment in June 2015, and the final report in December 2016. The final EPA report concludes that hydraulic fracturing activities can impact drinking water resources under some circumstances and identifies factors that influence these impacts.

A core element of the SDWA UIC program is setting requirements for proper well siting, construction, and operation to minimize risks to underground sources of drinking water. The Energy Policy Act of 2005 excluded hydraulic fracturing (except when diesel fuels are used) for oil, natural gas, or geothermal production from regulation under the UIC program. This statutory language caused regulators and the regulated community alike to raise questions about the applicability of permitting practices. As a result, EPA developed revised UIC Class II permitting guidance specific to oil and natural gas hydraulic fracturing activities using diesel fuels (EPA, 2022a). Although developed specifically for hydraulic fracturing where diesel fuels are used, many of the guidance's recommended practices are consistent with best practices for hydraulic fracturing in general, including those found in state regulations and model guidelines for hydraulic fracturing developed by industry and stakeholders. Thus, states and tribes responsible for issuing permits and/or updating regulations for hydraulic fracturing will find the recommendations useful in improving the protection of underground sources of drinking water and public health wherever hydraulic fracturing occurs. The guidance outlines for EPA permit writers, where they are the permitting authority, (i) existing Class II requirements for diesel fuels used for hydraulic fracturing wells, and (ii) technical recommendations for permitting those wells consistently with these requirements (EPA, 2022a).

EPA completed a stakeholder engagement effort in 2020 that sought input on how the agency, states, tribes, and stakeholders regulate and manage wastewater from the oil and gas industry. EPA released a draft report in May 2019 that described what it heard during its engagement for this study (EPA, 2022a). EPA accepted public input on the draft report and, after considering this input, published a final report. In many regions of the United States, underground injection is the most common method of managing fluids or other substances from shale gas extraction operations. Management of flowback and produced water via underground injection is regulated under the SDWA UIC program. The Clean Water Act effluent guidelines program sets national standards for industrial wastewater discharge to surface waters and municipal sewage treatment plants based on the performance of treatment and control technologies. Effluent guidelines for onshore oil and natural gas extraction facilities prohibit the discharge of pollutants into surface waters, except for wastewater that is of good enough quality for use in agricultural and wildlife propagation for those onshore facilities. On June 28, 2016, EPA promulgated pretreatment standards for the Oil and Gas Extraction Category (40 Code of Federal Regulations Part 435). These regulations prohibit discharge of wastewater pollutants from onshore unconventional oil and natural gas extraction facilities to publicly owned treatment works.[c]

On December 6, 2022, EPA issued a supplemental proposal to update, strengthen, and expand standards intended to significantly reduce emissions of GHG and other harmful air pollutants from the Crude Oil and Natural Gas source category (EPA, 2022b). First, EPA proposed standards for certain sources that were not previously addressed. Second, EPA proposed revisions that strengthen standards for sources of leaks, provide greater flexibility to use innovative advanced detection methods, and establish a super-emitter response program. Third, EPA proposed to modify and refine certain elements of the proposed standards in response to information submitted in public comments. Finally, EPA proposed details of the timelines and other implementation requirements that apply to states to limit CH_4 pollution from existing designated facilities in the source category under the Clean Air Act (EPA, 2022b).

1.3.1.3 Department of Energy

The Natural Gas Act requires DOE to make public interest determinations on applications to export LNG to countries where the United States does not have existing free-trade agreements. The Office of Fossil Energy and Carbon Management's (FECM) natural gas import–export regulatory program is implemented by the Division of Regulation in the Office of Regulation, Analysis, and Engagement. Typically, the Federal Energy Regulatory Commission (FERC) has direct regulatory responsibility over the siting, construction, and operation of LNG export facilities in the United States. In these cases, FERC leads the environmental impact assessments of proposed projects consistent with the National Environmental Policy Act, and DOE is typically a cooperating agency as part of these reviews (DOE, 2023a).

FECM's Point Source Carbon Capture Division's research, development, demonstration, and deployment portfolio facilitates the development of technologies and infrastructure that improve performance, reduce costs, and scale the deployment of technologies to decarbonize the industrial and power sectors and remove CO_2 from the atmosphere. Within the natural gas supply chain, these efforts include research and commercial-scale demonstration of technologies that advance carbon capture and storage on natural gas-fired power plants and industrial natural gas combustion streams (DOE, 2023a).

FECM is working to support efforts to decarbonize LNG terminals through deployment of carbon capture on gas separation and combustion streams and the use of electric motor drives supplied by net-zero emissions electricity. Decarbonizing LNG terminals is a key part of the effort to reduce life cycle emissions associated with the export of natural gas to global allies. Additionally, DOE has regulatory responsibilities related to LNG. Companies that want to export LNG must get authorization to do so from FECM. FECM's Methane Mitigation Technologies Division aims to eliminate non-trivial fugitive and vented CH_4 emissions from the natural gas supply chain to reduce the climate impacts from the production and use of natural gas. The

[c] "Publicly owned treatment works" is a term used in the United States to designate a sewage treatment plant owned, and usually operated, by a government agency. In the United States, publicly owned treatment works are typically owned by local government agencies and are usually designed to treat domestic sewage and not industrial wastewater.

division is focused on developing accurate, cost effective, and efficient technology solutions and best practices to identify, measure, monitor, and minimize CH_4 emissions from these sources.

DOE's shale gas research program brings together federal and state agencies, industry, academia, non-governmental organizations, and national laboratories to develop technologies that enable safe, environmentally sustainable oil and gas production. DOE's shale gas research program is tasked with calculating the risks of oil and gas exploration and production undertakings. DOE has funded several technology investigations through NETL that deal with produced water management and life cycle assessments of the natural gas value chain (DOE, 2023b).

On April 21, 2023, a Request for Information was issued by FECM to obtain input to inform DOE's research and development activities within the Office of Research and Development's Methane Mitigation Technologies Division and the Office of Carbon Management Technologies' Point Source Carbon Capture Division. In addition, such data and information could help inform the Office of Regulation, Analysis, and Engagement's capabilities to assess natural gas import and/or export applications under the Natural Gas Act of 1938, as amended. Through the Request for Information, DOE is requesting information on strategies and technologies that natural gas and LNG companies are deploying, or could deploy, to reduce GHG emissions and other air pollutants associated with natural gas delivered to liquefaction facilities, housed at liquefaction facilities, and being loaded, transported, and delivered to regasification facilities (DOE, 2023a).

1.3.2 States

States have the power to implement their own requirements and regulations for unconventional natural gas drilling with federal oversight. All states that produce natural gas have at least one agency charged with issuing new permits for production wells. While state requirements for permits can differ, any requirements set forth by federal regulations must be met in order for a state-level permit to be issued.

NETL evaluated the state regulatory programs for oil and natural gas production for their applicability and adequacy of protecting water resources (NETL, 2014). NETL reviewed regulations for permitting, well construction, hydraulic fracturing, temporary abandonment, well plugging, tanks, pits, and waste handling and spills. This evaluation revealed several key messages (NETL, 2014):

1. State oil and gas regulations are adequately designed to directly protect water resources through the application of specific programmatic elements such as permitting, well construction, well plugging, and temporary abandonment requirements.
2. Experience suggests that state oil and gas regulations related to well construction are designed to be protective of groundwater resources relative to the potential effects of hydraulic fracturing. However, development of best management practices related to hydraulic fracturing would assist states and operators in ensuring continued safety of

the practice, especially as it relates to hydraulic fracturing of zones near groundwater, as determined by the regulatory authority.

3. Many states divide jurisdiction over certain elements of oil and gas regulation between the oil and gas agency and other state water protection agencies. This is particularly evident in the areas of waste handling and spill management.
4. The implementation and advancement of electronic data management systems has enhanced regulatory capacity and focus. However, the inclusion of more environmental data is needed, as well as further work in the areas of paper-to-digital data conversion.

In 2014, EPA compiled a summary of state regulatory programs for oil and natural gas exploration, development, and production (EDP) solid waste management. This review was conducted by EPA personnel in the Office of Resource Conservation and Recovery within the Office of Solid Waste and Emergency Response. The review included relevant regulations for Ohio, Oklahoma, Pennsylvania, Texas, and West Virginia, which are presented below (EPA, 2014).

1.3.2.1 Ohio

Regulations concerning technical requirements for waste pits are found in Chapter 1501 of the Ohio Administrative Code (OAC) and Rule 1509 of the Ohio Revised Code (ORC), which contains the statutory authority for the regulations promulgated in the OAC as regulated by the Division of Mineral Resources Management in the Department of Natural Resources. The complete set of applicable regulations can be found in Appendix OH-3. Regulations relevant to this addendum include the following:

- OAC 1501:9-1-02 details the requirements for the permitting of wells, including the plan for disposal of water and other waste substances resulting from oil and gas exploration and production activities.
- OAC 1501:9-3-08 details temporary storage of saltwater and other related waste, including design criteria for storage pits.
- OAC 1501:9-9-05 specifies tank location restrictions, including setbacks from public roads, inhabited structures, wells, heaters, and other equipment.
- OAC 1501:9-9-03 requires pits of sufficient size and shape to be constructed adjacent to each drilling well to contain all the drilling muds, cuttings, saltwater, and oil.
- OAC 1501:9-9-05 specifies that where a hazard exists, any production equipment at the wellhead and related storage tanks must be protected by an earthen dike or earthen pit with a capacity to contain any substances produced by operation of the related oil or gas well.
- ORC 1509.072 discusses the obligation to restore the land surfaces after drilling operations have ceased, including removing all equipment, revegetating the affected area, preventing sedimentation and erosion, and authorizing the chief retains in the closure of a well.

- ORC 1509.22 discusses the prohibition of water contamination and covers storage and disposal of brine. This section also discusses the storage of waste fluids and the management allowances for these fluids.

1.3.2.2 Oklahoma

Regulations concerning technical requirements for oil field waste pits in Oklahoma are found primarily in Oklahoma Administrative Code, Title 165, Chapter 10, Subchapters 3 and 7 as regulated by the Oklahoma Corporation Commission Division of Oil and Gas. Regulations relevant to this addendum include the following:

- 165: 10-7-16 details minimum technical design standards for waste pits.
- 165:10-7-5 details operating requirements for pits, specifically operating standards in the event of a discharge, including reporting details and requirements along with record-keeping requirements.
- 165:10-7-16.(d) details operating requirements for oil and gas exploration and production activity pits.
- 165:10-3-16.(e) details closure requirements for pits.
- 165:10-3-17 details further closure requirements, primarily the return of the surface conditions at the site of the pit to their original state, free of trash, debris, and equipment, within 90 days of the completion of well activities.

1.3.2.3 Pennsylvania

Regulations concerning technical requirements for oil field waste pits in Pennsylvania are found primarily in Pennsylvania Code, Title 25 (Environmental Protection), Part 1 (Department of Environmental Protection), Subpart C (Protection of Natural Resources), Article I (Land Resources), Chapter 78 (Oil and Gas Wells) and Chapter 91 (General Provisions). Additional language can be found in Pennsylvania (PA) Act 13 of 2012. Regulations relevant to this addendum include the following:

- PA Act 13 of 2012 §3215 prevents wells from being sited in any floodplain if the well is to employ a pit or impoundment or a tank managing solid wastes from oil and gas exploration and production.
- PA Act 13 of 2012 §3216 requires that a well site be restored following cessation of drilling operations. This includes restoration of the earthwork or soil disturbed, removal of all drilling supplies and equipment within nine months after completion of the drilling well, and compliance with all applicable requirements of the Clean Streams Law. The restoration period is subject to an extension if certain conditions are met.
- PA Act 13 of 2012 §78.56 details requirements for pits and tanks that are used to manage waste temporarily. Some requirements include a minimum of 2 ft of freeboard for pits or impoundments, structural soundness of pits and tanks, minimum liner requirements, and waste separations and prohibitions.

- PA Act 13 of 2012 §78.57 details requirements for management of production fluids, including collection of brine and other fluids from the well operations, requirements for pits, removal and disposal of fluids, and restoration of the waste management units or facilities following the closure or cessation of operations.
- PA Act 13 of 2012 §78.61 details the requirements for disposal of drill cuttings, including criteria to be met to allow for disposal in a pit, criteria to be met to allow for disposal by land application, other methods of disposal of drill cuttings, and compliance requirements for disposal.
- PA Act 13 of 2012 §78.64 details secondary containment criteria to be met for tanks used on drill sites, including required capacity and inspection requirements.
- PA Act 13 of 2012 §78.65 details site restoration requirements following the cessation of operations at a well site.

1.3.2.4 Texas

Regulations concerning technical requirements for solid waste management of oil and gas exploration, production, and development in Texas are found primarily in the Texas Administrative Code, Title 16, Part 1, Chapters 1–20. The Railroad Commission of Texas (RRC) is the primary authority in Texas regarding the regulation of oil and natural gas. Regulations relevant to this addendum include the following:

- Rule §3.3 details that all tanks must be clearly identified by signage at all times.
- Rule §3.5 details that a permit is required, issued by the RRC, in order to drill, deepen, plug back, or reenter any oil, gas, or geothermal resource well. The rule does not include any required specifications for waste management in the permit.
- Rule §3.8 defines the various types and functions of pits that are to be found in the regulations. Additionally, the rule defines oil and gas waste. The rule defines what pits are prohibited, including for the storage of oil products, requirement to obtain a permit for a pit, authorized disposal methods, liner requirements, minimum freeboard, prevention of run-on from stormwater, draining of pits, and inspection of pit liners. The Rule details instances in which a pit may be used without a permit, including as a reserve pit, completion pit, or basic sediment pit. The Rule also notes that the pit operator must keep records detailing that the pit liner requirements are met.
- Rule §3.15 details the requirements for the removal of all surface equipment from inactive wells, including the removal of all tanks or tank batteries.
- Rule §3.22 details the requirements of screening or netting of pits to protect wildlife, specifically birds.
- Rule §3.57 details the requirements for reclaiming tank bottoms and disposal of other EDP wastes. This includes the requirement for a permit, the use of a reclamation plant, and other miscellaneous requirements.

- Rule §3.78 details financial assurances and fees required in order to commence drilling activities. These financial assurances include bonding requirements for varying operations and number of wells.
- Rule §4.620 prohibits the disposal of naturally occurring radioactive material (NORM) waste by burying it or applying it with the land surface without obtaining a permit. The section details that the disposal of NORM waste is subject to Rule §3.8.

1.3.2.5 West Virginia

The following are oil and natural gas solid waste regulations for the state of West Virginia (WV):

- WV Code Chapter 22 Art. 6 Section 7, Chapter 22 Art. 11 Section 1–27, and Chapter 22 Art. 6 details permitting requirements and authority.
- WV Code Chapter 22 Article 6 Section 7 details waste pit authority of the general permit.
- WV Code Chapter 22 Series 6A contains the Horizontal Well Control Act.
- WV Code Title 35 Series 8 details horizontal well permits regarding the requirements and handling of waste cuttings.

Additionally, documentation that dictates surface and groundwater pollution prevention requirements for WV include the following:

- General Water Pollution Control Permit
- Erosion and Sediment Control Field Manual
- 35-8 Rules Horizontal Well Development
- 35-1 Water Pollution Control Rule

Below is a summary of some relevant sections of the WV code regarding oil and natural gas solid waste regulations relevant to this Addendum:

- §35-1-7 details requirements for dikes, berms, and retaining walls at oil and gas operations, requirements for secondary containment of tanks or tank systems, and other associated mechanical operational requirements.
- §35-4-16 details design and operation criteria for pits and impoundments.
- §35-4-21 describes design and construction requirements for pits and impoundments with a capacity greater than 5,000 barrels, including inspections.
- §35-2-3 requires that a permit be obtained by the Division of Environmental Protection, Office of Oil and Gas prior to the commencement of any solid waste facilities at the site of oil and gas exploration and production.
- §35-4-10 details financial assurance requirements for oil and gas exploration and production activities, including the demonstration of financial responsibility of individual

and grouped wells, coincidence with permit application for financial assurance, and the varying forms of financial assurance allowable.

- §35-8-5 details requirements for permits, notice, and review of horizontal wells, including siting restrictions, financial assurance for horizontal wells, and permitting requirements.

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2 GREENHOUSE GAS EMISSIONS AND CLIMATE CHANGE

CH_4 and CO_2 emissions from the LNG life cycle and natural gas end uses vary widely across different regions and supply chains. This section presents a review of contemporary (2014 and after) life cycle analysis (LCA) as it pertains to LNG and natural gas GHG emissions.

2.1 INTRODUCTION

To account for all sources of GHG emissions in the natural gas supply chain, and to evaluate their relative contributions and mitigation opportunities, a systems-level perspective is both necessary and preferred. LCA is one type of systems approach available to account for the different sources of GHG emissions in the natural gas supply chain. LCA specifically considers the material and energy flows of an entire system from cradle to grave. Where the cradle refers to the extraction of resources from the earth, and the grave refers to the final use and disposition of all products.

Depending on the type of LCA conducted, different system boundaries can be put in place to more accurately estimate the GHG emissions associated with natural gas. Generally, GHG emissions occur from the beginning of the natural gas supply chain (during exploration) through the end (during utilization). In some cases, an LCA may not consider every step of the natural gas supply chain within its analysis framework. This can happen for a variety of reasons, including lack of emission data for a particular step or set of steps, or simply to focus specifically on the emissions associated with one particular part step. Exhibit 2-1 provides an illustration of the natural gas supply chain with examples of key emissions sources (Balcombe et al, 2016).

Exhibit 2-1. Natural gas supply chain with examples of key emission sources

Permission pending from Balcombe et al. (2016)

There are two primary approaches used to conduct natural gas LCA: 1) top-down and 2) bottoms-up (Rutherford et al., 2021; Alvarez et al., 2018; Balcombe et al., 2016). A top-down approach 1) measures the atmospheric concentrations of CH_4 as reported by fixed ground monitors, mobile ground monitors, aircraft, and/or satellite monitoring platforms; 2) aggregates the results to estimate total CH_4 emissions; and 3) allocates a portion of these total emissions to each of the different supply chain activities. A bottoms-up approach measures CH_4 emissions directly from each source of emissions, then aggregates and extrapolates these measurements to estimate emissions for an entire region or process. Both approaches have their advantages and disadvantages.

For example, several studies (Rutherford et al., 2021; Alvarez et al., 2018; Balcombe et al., 2016) have noted that top-down approaches may lead to a general upward bias in emissions reporting while bottoms-up approaches may lead to a general downward bias in emissions reporting. There are several factors that may lead to these biases, which can be generally explained as follows:

- Top-down approaches sometimes fail to distinguish between different sectors. For example, aircraft that are used to collect emissions data for a particular area may struggle to distinguish between the CH_4 emissions coming from a natural gas processing facility in the area from those coming from a near-by dairy farm. This can lead to incorrect contributions of total CH_4 emissions to specific natural gas activities.
- Bottoms-up measurements sometimes fail to capture "super emitters"—a small number of facilities (or equipment) who emit disproportionately large quantities of emissions. Because bottoms-up approaches measure emissions from individual sources and because super emitters, by definition, represent only a small proportion of the total number of facilities (or equipment) represented within the natural gas supply chain, it can be challenging to accurately capture the contributions of a super emitter activity to total emissions.

Alvarez et al. (2018) also notes that in many bottoms-up approaches to modeling, operator cooperation is required to obtain site access for accurate emissions measurements. Operators with lower-emitting sites are plausibly more likely to cooperate with the conduct of such studies and workers are plausibly more likely to be careful to avoid errors or fix problems when measurement teams are on site or about to arrive, which could lead to a downward bias in estimates of potential emissions (Rutherford et al., 2021; Alvarez et al., 2018; Balcombe et al., 2016).

Another key difference in LCA methodology or assumptions that can lead to differences in LCA outputs (i.e., estimates of emissions) is climate-forcing impacts of CH_4 used (Balcombe et al., 2016). CH_4 emissions have a large short-term climate-forcing impact[d] compared to CO_2. The instantaneous forcing impact of CH_4 is around 120 times that of CO_2 on a mass basis. CH_4, however, only has an average lifespan of 12 years after which it oxidizes into CO_2. CO_2

[d] Climate or radiative forcing, a measure, is defined by the Intergovernmental Panel on Climate Change (IPCC) as the influence a given climatic factor has on the amount of downward-directed radiant energy impinging upon Earth's surface.

emissions remain in the atmosphere for much longer—25 percent CO_2 emissions still exists after 1,000 years (Balcombe et al., 2016). Consequently, while the climate-forcing impact of CH_4 emissions changes significantly over time, the impact of CO_2 emissions remains much more constant.

Typically, studies use global warming potential (GWP) to compare the climate impact of emissions of different GHGs such as CH_4 with CO_2. The GWP is defined as a measure of how much energy the emissions of 1 ton of a gas will absorb over a given period, relative to the emissions of 1 ton of CO_2 (Balcombe et al., 2016). The IPCC progressively raised the GWP for CH_4 to 28 over a 100-year period and 84 over a 20-year period in their Fifth Assessment Report (AR5) published in 2014 (Stern, 2022). IPCC's Sixth Assessment Report (published in 2021) raised the GWP of CH_4 to 29.8 over a 100-year horizon but reduced the 20-year horizon factor to 82 (Stern, 2022). Adding climate feedback mechanisms and oxidation, these figures were increased to 36 and 87.15, respectively in the IPCC's Sixth Assessment Report.

To illustrate, if the GWP of CH_4 for a time horizon of 100 years is 36, this means that a pulse emission of CH_4 absorbs 36 times more energy than CO_2 over 100 years on average. Note that the GWP of CH_4 for a time horizon of 100 years does not give any information on the climate forcing of CH_4 at the end of the 100 years; it gives only the average impact across the 100 years. Additionally, the use of a single value to compare GHGs does not consider the changing impacts over time. It is important to consider the GWP used when analyzing the outputs of an LCA, particularly when comparing the outputs of two or more LCAs (Balcombe et al., 2016).

2.2 FEDERALLY-FUNDED LCA

NETL has used LCA to calculate the environmental impacts of natural gas production and use for the generation of electric power for nearly a decade (NETL, 2023). Their work has been documented in a series of reports produced between 2010 and 2019.[e] Together, these reports provide in-depth assessments of the potential GHG emissions resulting from unconventional natural gas production in the United States. The GHG emissions results recorded in the NETL 2019 report considers five stages of the natural gas supply chain, which are visualized in Exhibit 2-2 (NETL, 2019):

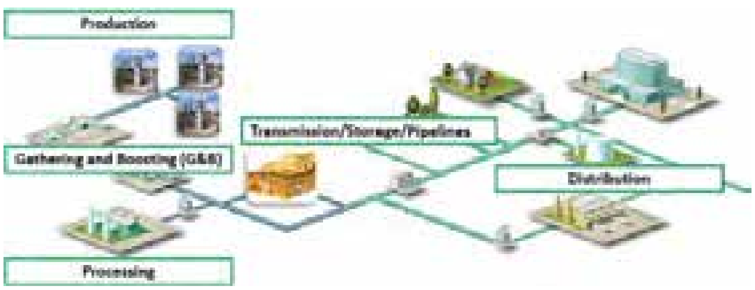
1. **Production:** Sources of emissions include the gas vented from pneumatically controlled devices and fugitive emissions from flanges, connectors, open-ended lines, and valves. When vapor recovery units are feasible, vented gas is captured and flared; otherwise, vented gas is released to the atmosphere. Production operations also include the combustion of natural gas and diesel in compressors and other equipment.
2. **Gathering and Boosting (G&B):** Natural gas G&B networks receive natural gas from multiple wells and transport it to multiple facilities. G&B sites include acid gas removal, dehydration, compressors operations, pneumatic devices, and pumps.
3. **Processing:** A natural gas processing facility removes impurities from natural gas, which improves its heating value and prepares it for pipeline transmission. Natural gas

[e] The GHG results in the NETL (2019) report supersede the GHG results in the previous NETL reports.

processing facilities include acid gas removal, dehydration, hydrocarbon liquids removal, and compression operations.

4. **Transmission Stations, Storage Facilities, and Transmission Pipelines:** A natural gas transmission system is a network of large pipelines that transport natural gas from processing facilities to the city gate (the point at which natural gas can be consumed by large-scale consumers or transferred to local distribution companies). Transmission stations are located along natural gas transmission pipelines and use compressors to boost the pressure of the natural gas.
5. **Distribution:** Natural gas distribution networks transport natural gas from the city gate to commercial, residential, and some industrial consumers. This analysis uses the distribution portion of the supply chain only for the upstream functional unit; distribution is not necessary for the functional unit of electricity in which natural gas power plants receive natural gas directly from transmission pipelines.

Exhibit 2-2. Supply chain stages that compose the overall LCA boundary



The flexible, consistent framework of NETL's LCA model allows different natural gas sources to be compared on a common basis (per megajoule [MJ] of delivered natural gas). In the NETL (2019) report, five types of natural gas are considered:

1. **Conventional natural gas** is natural gas extracted via vertical wells in high permeability formations that do not require stimulation technologies for primary production.
2. **CBM** is extracted from coal seams and requires the removal of naturally occurring water from the seam before natural gas wells are productive.
3. **Shale gas** is extracted from low permeability formations and requires hydraulic fracturing and horizontal drilling.
4. **Tight gas** is extracted from non-shale, low permeability formations and requires hydraulic fracturing and directional drilling.
5. **Associated gas** is found with petroleum (either dissolved in oil or in a gas cap in a petroleum formation) and is produced by oil wells.

EPA estimates oil and natural gas CH_4 emissions in the annual Greenhouse Gas Inventory (GHGI) it produces. The GHGI uses a bottoms-up approach to estimate national CH_4 emissions.

In its 2019 LCA analysis of the natural gas supply chain, NETL used the GWP reported in the AR5. Other key input data was sourced from EPA's GHGI, Drilling Info (DI Desktop), and EIA. Results from the 2019 NETL LCA analysis performed suggested the following:

- The life cycle GHG emissions associated with the U.S. natural gas supply chain were 19.9 grams (g) of carbon dioxide equivalents (CO_2e) per MJ of natural gas delivered (with a 95% mean confidence interval of 13.1–28.7 g CO_2e per MJ).
- The top contributors to CO_2 and CH_4 emissions were combustion exhaust and other venting from compressor systems. Compressor systems are prevalent in most stages of the natural gas supply chain and as such were key contributors to the total life cycle emissions estimated.
- Emission rates were highly variable across the entire supply chain. According to the study (NETL, 2019), the national average CH_4 emissions rate was 1.24 percent, with a 95 percent confidence interval ranging 0.84–1.76 percent.

Exhibit 2-3 shows the upstream GHG emissions from the different parts of the natural gas supply chain. The blue bars represent CO_2 emissions, the green bars represent CH_4 emissions, and the orange bars represent nitrous oxide (N_2O) emissions. The vertical black lines in Exhibit 2-3 and Exhibit 2-4 represent the error bars in this analysis, and the shaded grey area represents the 95 percent confidence interval.

Exhibit 2-3. Life cycle CH_4 emissions from the U.S. natural gas supply chain

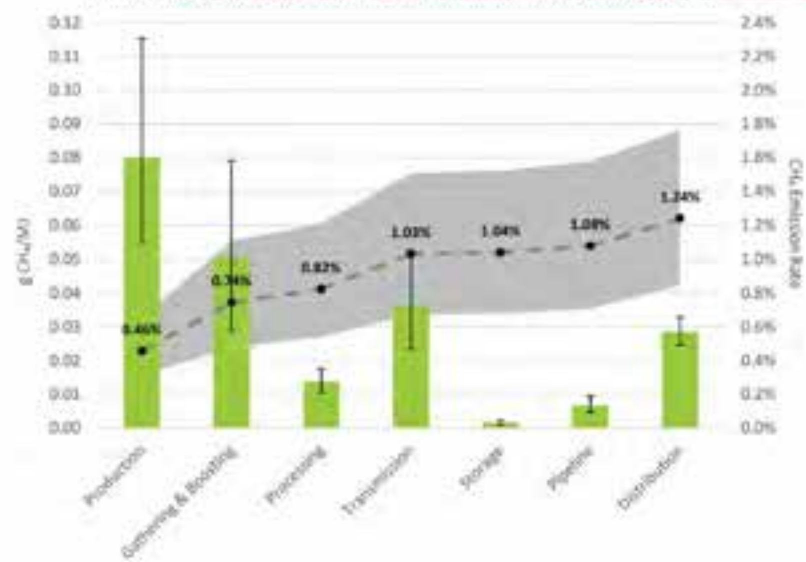


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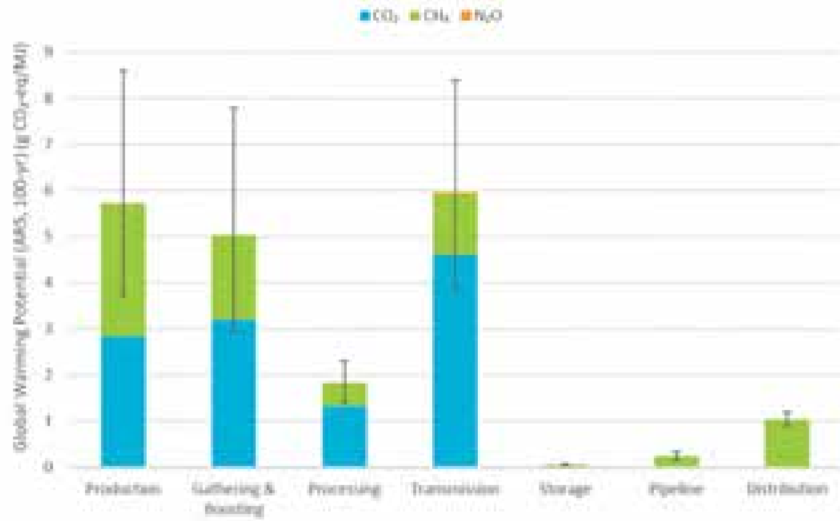
Exhibit 2-4. Life cycle GHG emissions for the U.S. natural gas supply chain

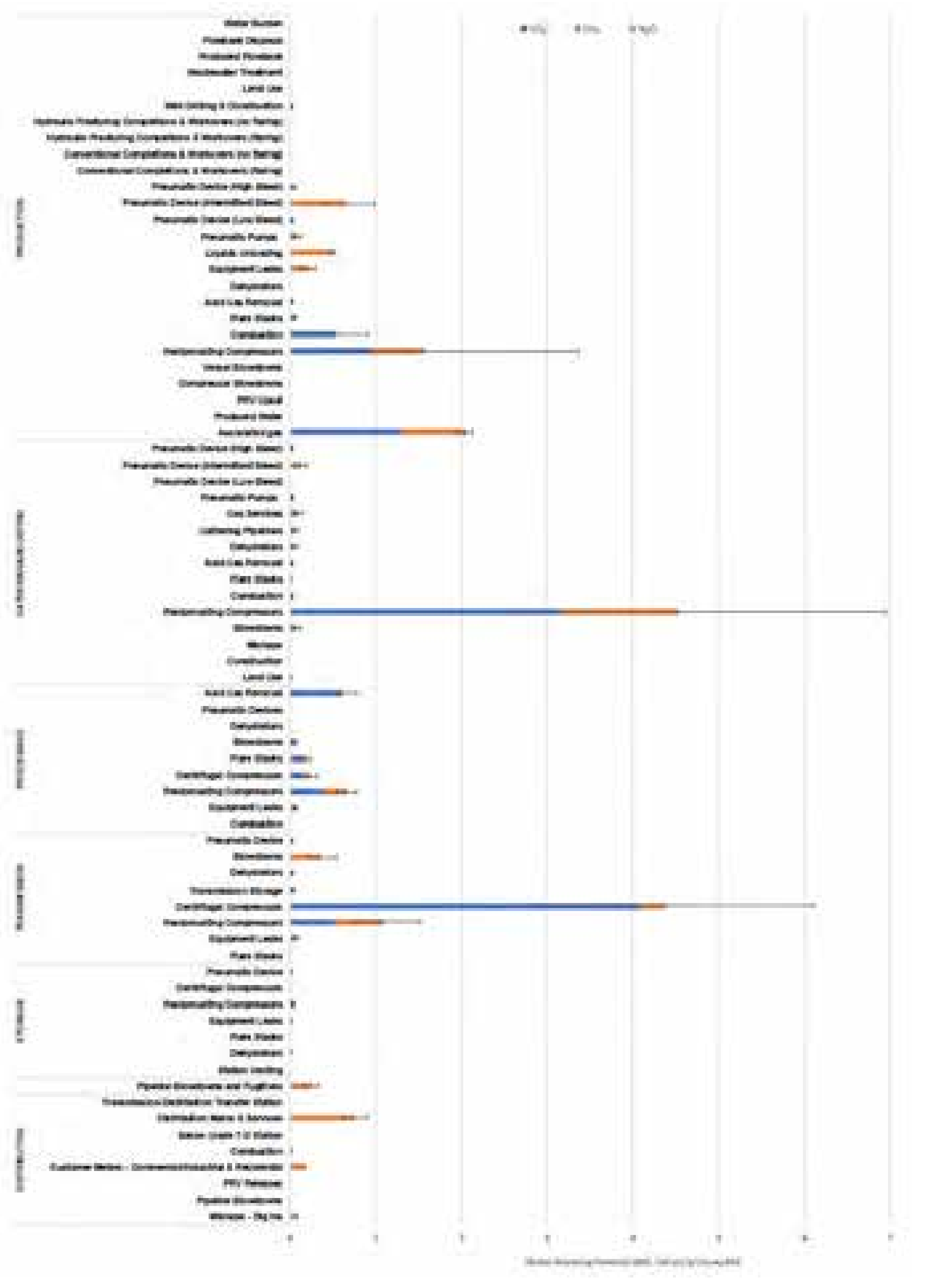


Key drivers of GHG emissions results for the entire natural gas supply chain are illustrated in Exhibit 2-5 (NETL, 2019). Pneumatic devices and compression systems represent a significant portion of the total life cycle GHG emissions associated with the natural gas supply chain (NETL, 2019). Pneumatic devices are used to operate level controllers, valves, and other equipment at natural gas facilities. According to EPA's GHGI, production pneumatics emitted 1,060 kilotons of CH_4 in 2017, accounting for 16 percent of the total CH_4 emissions from the natural gas supply chain. Pneumatic device activity is concentrated at production facilities and there were 833,000 pneumatic devices used by U.S. production facilities in 2019 (NETL, 2019).

Natural gas is compressed for transport from processing facilities to end-consumers. As such, upstream GHG emissions are sensitive to pipeline distances and the number of compressors along these pipelines that the natural gas must pass through. The energy intensity of compression and the fugitive CH_4 emissions from compressors both contribute to upstream GHG emissions (NETL, 2019).

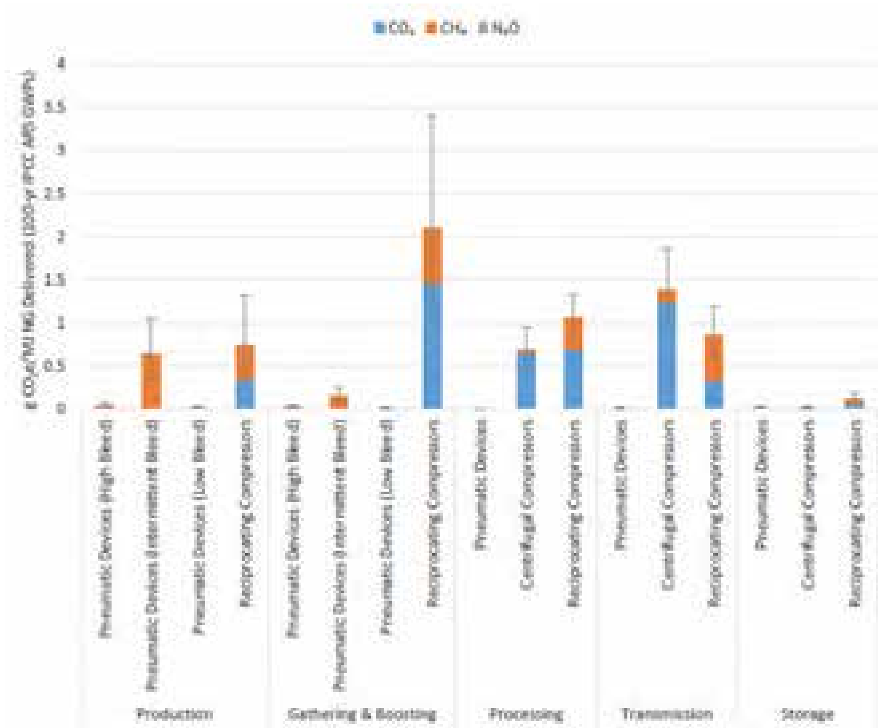
In addition to being a source of CH_4 emissions, compressors are also a source of CO_2 emissions. Most compressors in the U.S. pipeline transmission network are powered by natural gas that is withdrawn from the pipeline itself. Electric motors are not widely used by natural gas pipelines but are installed where local emission regulations limit the use of internal combustion engines or where inexpensive electricity is available. Approximately three percent of compressors used by the natural gas transmission network are electrically driven.

Exhibit 2-5. Detailed GHG emission sources for the U.S. natural gas supply chain



Two sources of CH_4 emissions from compressor systems include 1) CH_4 that slips through combustion exhaust and 2) CH_4 that escapes through compressor seals or packing. Natural gas systems use both centrifugal and reciprocating compressors. Centrifugal compressors are more appropriate for pressure boosting applications in a steady-state applications (such as a transmission pipelines), while reciprocating compressors are more appropriate when gas flow is variable and when large increases in pressure are required. Centrifugal compressors are typically driven by gas-fired turbines but, in some instances, are driven by an electric motor. Reciprocating compressors are driven by gas-fueled engines. Exhibit 2-6 illustrates the emissions associated with pneumatic devices and compressors.

Exhibit 2-6. GHG emissions from pneumatic devices and compressors across the NG supply chain

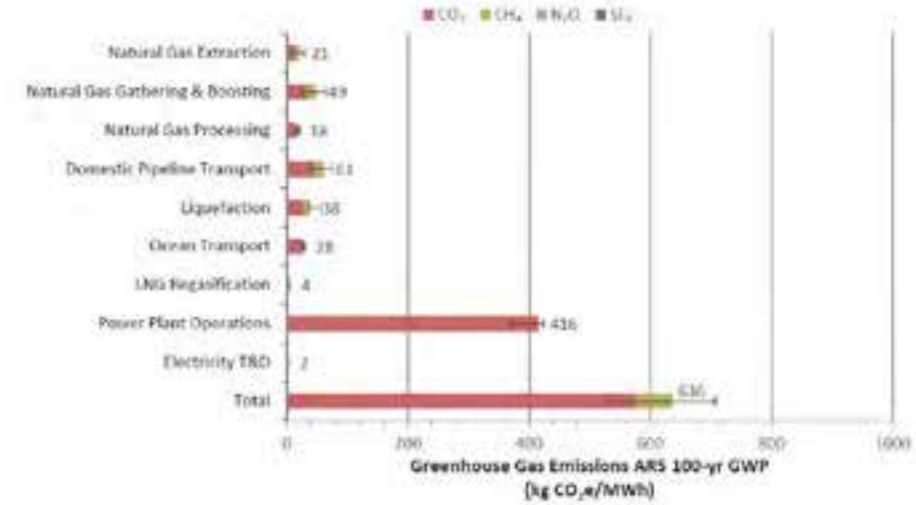


For all natural gas production types, the GHG emissions results produced by an LCA are sensitive to production rates and episodic emissions (either liquid unloading or workovers). In addition to its characterization of domestic upstream natural gas, NETL also developed life cycle data for exported LNG, including the GHG emissions from liquefaction, transport, regasification, and the combustion for electricity generation (NETL, 2019).

The NETL (2019) report that analyzed the lifecycle emissions of exporting U.S. LNG to Europe yielded the emissions results (assuming end-use in electricity generation) detailed in Exhibit 2-7.

Commented [LBD12]: Suggest somewhere a comment be made that the supply chain study presented above is "cradle to gate," and excludes end-use, while the LNG study is more truly "cradle to grave," and does include end-use (power generation), meaning extra care should be taken by readers in comparing results and figures.

Exhibit 2-7. GHG emissions from exporting LNG from the United States to Europe



Littlefield, Rai, and Skone (2022) show that geography matters in terms of the GHG emissions estimated for the global natural gas supply chain, where natural gas is produced and ultimately used plays a tremendous role in the total amount of GHG emissions estimated for the supply chain. As such, a national average value is not necessarily an adequate representation of an individual (source to sink) natural gas supply chain. Littlefield, Rai, and Skone (2022) provide a detailed life cycle perspective on GHG emissions variability where natural gas is produced and where it is delivered. They disaggregate transmission and distribution infrastructure into six regions, balance natural gas supply and demand locations to infer the likely pathways between production and delivery, and incorporate new data on distribution meters. They find the average transmission distance for U.S. natural gas is 815 kilometers (km) but ranges 45–3,000 km across estimated production-to-delivery pairings examined (Littlefield, Rai, and Skone, 2022). In terms of total GHG emissions, their results suggest the delivery of 1 MJ of natural gas to the Pacific region has the highest mean life cycle GHG emissions (13.0 g CO_2e/MJ) and the delivery of natural gas to the Northeastern region of the United States has the lowest mean life cycle GHG emissions (8.1 g CO_2e/MJ).

Commented [LBD13]: How does this compare with other analyses we rely on? Do we rely on national averages elsewhere

Commented [LBD14]: Elsewhere DOE has stated that it can't determine where NG supplies for particular LNG facilities would come from - does this track or contradict those statements?

In 2020, NETL collaborated with industry and published an analysis of Our Nation's Energy Future's (ONE Future) portfolio of assets (Rai et al., 2020). ONE Future is a natural gas industry partnership dedicated to improving the efficiency of the domestic natural gas supply chain. ONE Future represents 1–13 percent of total throughput in the respective segments of the natural gas industry supply chain. The expected life cycle CH_4 emission rate for ONE Future average natural gas is 0.76 percent (with a 95 percent confidence interval ranging 0.49–1.08 percent). The expected life cycle CH_4 emission rate for the U.S. average scenario is 1.06 percent. In terms of IPCC 100-year GWP, the ONE Future and U.S. average scenarios emit 9.7 and 14.1 g CO_2e/MJ of delivered natural gas, respectively.

2.3 OTHER NATURAL GAS ANALYSES

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Balcombe et al. (2016) document the wide range of CH_4 emissions estimates across the natural gas supply chain. Estimates of combined CH_4 and CO_2 emissions range 2–42 g CO_2e/MJ. A significant driver of this wide range are 1) the emissions associated with upstream natural gas production, and 2) whether the natural gas is ultimately converted to LNG or not. This sub-section explores these different segments of the supply chain.

2.3.1 Natural Gas Production Analyses

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Several studies have found that CH_4 emissions from the natural supply chain are about 1.5–2.5 times the amount reported in EPA's GHGI (Rutherford et al., 2021; Alvarez et al., 2018; Balcombe et al., 2016). Much of the discrepancy can be attributed to differences in the analyses performed for the production segment of the natural gas supply chain where super emitters and emissions intensive equipment are both prevalent (Rutherford et al., 2021; Alvarez et al., 2018; Balcombe et al., 2016).

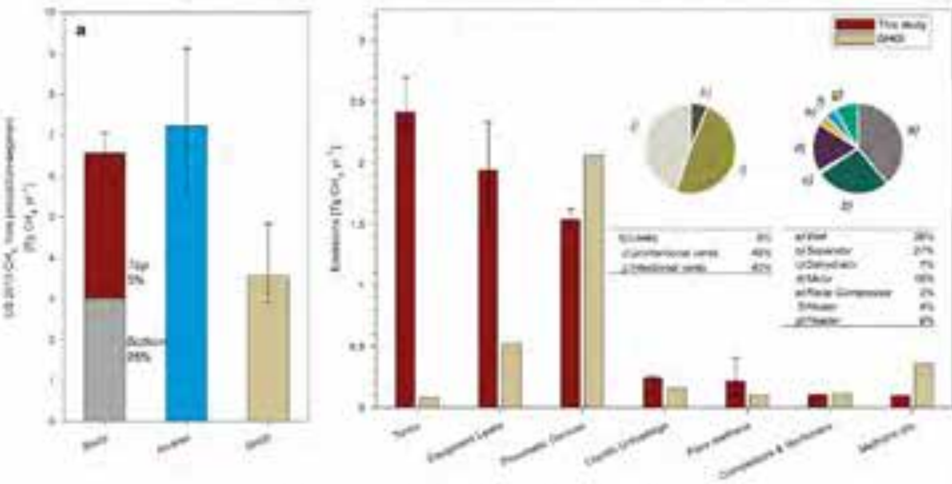
To isolate specific sources of disagreement between EPA's GHGI and other studies, Rutherford et al. (2021) reconstruct EPA's GHGI emission factors beginning with the underlying datasets and uncover some possible sources of disagreement between inventory methods and top-down studies. The adjusted emissions factors are direct inputs in the Rutherford et al. (2021) study outputs. Rutherford et al. uses a bottoms-up measurement approach, yet the approach differs from the GHGI in that it applies a bootstrap resampling statistical approach to allow for inclusion of infrequent, large emitters, thus, robustly addressing the issue of super-emitters.

Rutherford et al. (2021) estimate the mean, production-normalized emissions rate from the production segment as 1.3 percent (1.2–1.4 percent at 95 percent confidence interval, based on gross natural gas production of 32 Tcf and an average CH_4 content of 82 percent), slightly lower than Alvarez et al., 2018) who estimate it at 1.4 percent. Rutherford et al. (2021) estimate mean natural gas production-segment CH_4 emissions as equal to 6.6 teragrams (Tg) per year (6.1–7.1 Tg per year, at 95 percent confidence interval). Both the results of Rutherford et al. (2021) and Alvarez et al. (2018) are approximately two times larger the estimates of the 2015 EPA GHGI, which suggests 3.6 Tg of emissions per year (year 2015 data, excludes offshore systems) come from the natural gas production segment.

Importantly, the difference in U.S. production-segment emissions between the Rutherford et al. (2021) study and EPA's GHGI is approximately the same volume as Rutherford et al. (2021) study estimate of contribution from super-emitters (top 5 percent of emissions events). Given that Rutherford et al. (2021) results match the Alvarez et al. (2018) site-level results, the former concludes that the divergence between the GHGI and top-down/site-level studies is not likely to be due to any inherent issue with the bottoms-up approach. A results comparison of the

Rutherford et al. (2021) study, the Alvarez et al. (2018) study, and 2015 EPA GHGI data can be found illustration in Exhibit 2-8.

Exhibit 2-8. Comparison of GHG Emissions Results from Rutherford et al., Alvarez, et al., and EPA GHGI



Permission pending from Rutherford et al. (2021)

2.3.2 LNG Studies

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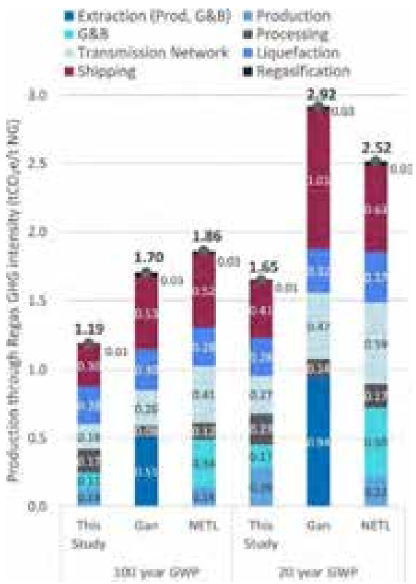
Relative to traditional natural gas supply chains where pipelines are primarily the means by which natural gas is transported, LNG supply chains involve liquefaction, shipping, and regasification stages. Each of which drive even greater variability in emissions profiles in LCA studies. A review of 37 global LNG supply scenarios between the United States and China by Gan et al. (2020) concluded that GHG emissions intensities varied by about 150 percent. Abrahams et al. (2015) note that emissions from the shipping of LNG exports from the United States to ports in Asian and European markets account for only 3.5–5.5 percent of precombustion life cycle emissions; hence, shipping distance is not a major driver of GHGs in the LNG supply chain.

At the end of 2020, Cheniere was the largest exporter of LNG from the United States in terms of volume. Roman-White et al. (2021) developed an LCA framework to estimate GHG emissions representative of Cheniere's LNG supply chain, considering both upstream and downstream sources of emissions from Cheniere's Sabine Pass Liquefaction facility using supplier-specific data collected from wellhead through ocean transport. Roman-White et al. (2021) compare the GHG emissions intensity of Cheniere LNG to two similar assessments of emission intensity from U.S. LNG transported to China (Gan et al., 2020; NETL, 2019). The results of their comparison are illustrated in Exhibit 2-9.

Exhibit 2-9. Comparison of GHG emissions results from Roman-White et al., Gan et al., and NETL



Used with permission from Roman-White et al. (2021)

The NETL (2019) LNG study uses more recent production emission data (2016 data) than Gan et al. (2020). The study is based on natural gas production in Appalachia with relatively low emissions intensity. The NETL analysis differs from the Roman-White et al. study primarily in the intensity of the G&B and transmission stages, which are driven by differences in individual facility performance.

When modeling transmission compression, the NETL (2019) study assumes a factor of 0.97 horsepower-hour (HPh)/thousand cubic feet (Mcf) to estimate the transmission station throughput (derived from NETL-published parameters). The average ratio of HPh to Mcf of throughput, from Cheniere's known suppliers (used in the Roman-White et al. study) is 0.27 HPh/Mcf, which is based on supplier data collection completed. For modeling gas from other transmission operators, the GHGRP does not publicly provide the throughput of compressor stations. As such, the Roman-White et al. (2021) study assumes 0.29 HPh/Mcf based on data reported by EIA.

The higher factor used by the NETL (2019) study results in increased fuel consumption across the transmission network. The Roman-White et al. liquefaction GHG intensity is 8–13 percent less than the intensity estimated by Gan et al. and is comparable to the NETL (2019) study estimate on a 100-year basis. The Roman-White et al. ocean transport stage emission intensity is 42–60 percent less than the transport emission intensity of Gan et al. (2020), and 35–42 percent less than that of the NETL (2019) study.

Jordaan et al. (2022) estimates the global average life cycle GHG emissions from the delivery of gas-fired electricity to be 645 gCO_2e per kilowatt hour (kWh) (334–1,389 gCO_2e per kWh), amounting to 3.6 gCO_2e yr−1 in 2017 (10 percent of energy-related emissions). This result is within range of the results obtained by Roman-White et al. (2021), who report life cycle GHG emissions of 524 gCO_2e kWh for electricity in China from LNG supplied by U.S. LNG exporter Cheniere, and 636 gCO_2e per kWh reported by NETL (2019).

Cai et al. (2017) assess GHG emissions of using compressed natural gas and LNG as transportation fuels by three heavy-duty natural gas vehicles types from a wells-to-wheels perspective. Cai et al. find that natural gas vehicle wells-to-wheels GHG emissions are largely driven by the vehicle fuel efficiency, as well as CH_4 leakage rates of both the NG supply chain and vehicle end use; the study estimates wells-to-wheels GHG emissions of natural gas vehicles to be slightly higher than those of the diesel counterparts given the estimated wells-to-wheels CH_4 leakage.

2.4 Mitigation Measures

Compressor seals include the wet seals used by the centrifugal compressor and the rod packing used by reciprocating compressors. Wet seals surround the rotating shaft of a centrifugal compressor with oil, which prevents gas leakage from the compressors. The oil used by wet seals must be continuously regenerated, which releases CH_4 into the atmosphere. By replacing wet seals with mechanical dry seals, the CH_4 emissions from centrifugal compressors can be reduced.

Reciprocating compressors prevent CH_4 leakage by encasing each compressor rod with a set of oil-coated, flexible rings. Proper maintenance and routine replacement of these rings prevents unnecessary leakage of CH_4. Storage tanks hold flowback water and liquid hydrocarbons recovered from the production stream. Variable loading levels and temperatures cause the venting of CH_4 and other gases from these tanks. By installing vapor recovery units on storage tanks, producers can reduce emissions from natural gas production. The captured emissions can be combusted on site to provide process energy, or they can be channeled to the sales stream.

Pneumatic controllers use gas pressure to open and close valves throughout a natural gas production and processing system. Natural gas is commonly used to pressurize pneumatic control systems. The bleeding of natural gas from pneumatic controllers vents CH_4 to the atmosphere. The GHG impact of pneumatic control systems can be reduced by installing pneumatic systems that use pressurized air instead of pressurized natural gas.

Since the regulations focus on reduced emissions completions (RECs), they are more applicable to unconventional wells. RECs are equipment that allow the capture of gas during flowback, either to be sent to the product line or, if this is not feasible, to be flared. However, the regulations also mandate emission reductions from pneumatically controlled valves and compressor seals, which are two types of emission sources common to conventional and unconventional technologies. Flowback emissions are governed by whether RECs are used.

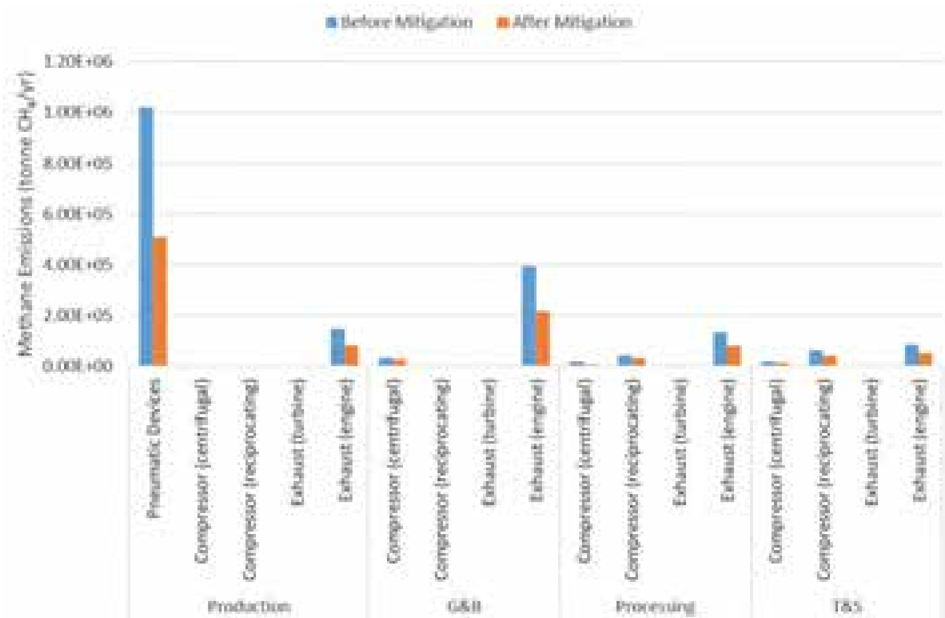
The data suggest that the use of this equipment reduces completion emissions by approximately 75−99 percent. For the most established unconventional gas industry, the United States, the use of RECs is compulsory. However, once RECs are employed and CH_4 is flared to some degree, resultant CO_2 emissions from flaring may become significant (Balcombe, 2016).

An NETL (2020) report notes that compressed-air pneumatics are a mature technology that reduces CH_4 emissions from pneumatic systems. The technology replaces existing devices, which are actuated by natural gas, with devices that are actuated with compressed air. This requires the addition of electric-powered air compressors at natural gas facilities but can result in zero CH_4 emissions from pneumatics. A barrier to implementation of compressed-air pneumatics is electricity availability. The United States has an extensive electricity grid, but grid connections are not always near production sites. The same NETL (2020) report notes that proven technologies exist for reducing CH_4 emissions from compression systems:

- Centrifugal compressors emissions can be reduced by replacing wet seals with dry seals. These seals are used around the rotating shaft of the compressor and prevent high pressure gas from escaping the compressor. Wet seals involve the use of recirculating oil that emits 40–200 standard cubic feet (scf) of natural gas per minute (min). Dry seals use gas to seal the compressor shaft and emit only 6 scf/min. The replacement of wet seals with dry seals reduces centrifugal compressor emissions by 85–97 percent.
- Reciprocating compressor emissions can be reduced by replacement of rod packing. Packing prevents gas from moving around piston rods and escaping the compression cylinder. New packing that is properly installed on a well-maintained compressor will emit about 12 scf/hour. The emission rate for old or poorly installed packing can range 25–67 scf/hour. When compared to emission rate for new packing, this equates to potential emission reductions of 52–82 percent. Rod packing replacement is a mature technology, but there are new technologies that can also reduce reciprocating engine exhaust slip. These new technologies include advanced materials that increase piston rod service life while reducing rod wear and Teflon-coated rings that reduce friction while maintaining a tight seal. There are no data on the emission reduction potentials of these new technologies.
- The majority of the CH_4 emissions from reciprocating compressors are due to the CH_4 slip from engine exhaust. Comparing the exhaust emission factors for rich burn and lean burn engines shows that lean burn engines have a combustion effectiveness of 97 percent and lean burn engines have combustion effectiveness of 99 percent. Air-fuel-ratio controls are an option for improving the combustion effectiveness of lean burn engines while keeping NOx emissions low. More research is required to understand the limits of air-fuel-ratio controls but, for this analysis, it is assumed that they can increase the combustion effectiveness of a lean burn engine by 97–99 percent.

Exhibit 2-10 illustrates the impact of these mitigation approaches.

Exhibit 2-10. Illustration of mitigation measure impact for pneumatic devices and compressors



Balcombe et al. (2018) note that pre-emptive maintenance and a faster response to high emission detection are methods for reducing the impact of super emitters. Identifying a cost-effective solution is imperative and much attention is being given to developing lower cost emission monitoring and detection equipment. As Brandt et al. (2016) point out, identifying larger leaks from the highest emitters may be carried out using less sensitive, and consequently cheaper, detectors in areas at the highest risk.

Alvarez et al. (2018) note that key aspects of effective mitigation include pairing well-established technologies and best practices for routine emission sources with economically viable systems to rapidly detect the root causes of high emissions arising from abnormal conditions. The latter could involve combinations of current technologies such as on-site leak surveys by company personnel using optical gas imaging, deployment of passive sensors at individual facilities or mounted on ground-based work trucks, and in situ remote-sensing approaches using tower networks, aircraft, or satellites. Over time, the development of less failure-prone systems would be expected through repeated observation of and further research into common causes of abnormal emissions, followed by reengineered design of individual components and processes.

With respect to liquefaction, Mokhatab et al. (2014) note that most of the plant energy consumption and resultant emissions in natural gas liquefaction facilities occur in the compressor drivers where fuel energy (usually natural gas) is converted to mechanical work (or electricity in case of electrically driven compressors). Due to the energy consumption scale of the LNG plants, any enhancement to the energy efficiency of a plant will result in a significant reduction in gas consumption and consequently CO_2 emissions (Mokhatab et al., 2014).

There are two ways to increase the energy efficiency of LNG plants: 1) liquefaction cycle enhancement and 2) driver cycle enhancement. Liquefaction cycle enhancements reduce the compressor power and consequently the compressor driver's fuel consumption. Driver cycle enhancement reduces the amount of fuel consumption to generate a specific amount of power. Typical fuel sources for natural gas liquefaction cycles include either pure refrigerant in cascade cycles, expansion-based cycles, or mixed refrigerant cycles.

Pure refrigerant cycles have a constant evaporating temperature that is a function of the saturation pressure. Mixed refrigerant cycles do not maintain a constant evaporating temperature at a given pressure. Their evaporating temperature can range and change depending on the pressure and composition. A refrigerant mixture of hydrocarbons and nitrogen is chosen so that it has an evaporation curve that matches the cooling curve of the natural gas with the minimum temperature difference. As such, small temperature differences reduce entropy generation and, thus, improve thermodynamic efficiency, reduce power consumption, and reduce the emissions associated with liquefaction facilities (Mokhatab et al., 2014).

A study from Pospíšil et al. (2019) notes that a certain part of the energy spent on liquefaction can be recovered by the utilization of cold stream from LNG. The amount of usable cold is given by thermophysical properties of natural gas and corresponds to 830 kilojoule (kJ)/kg of LNG. This cold energy can be recovered during the regasification process. Regasification is carried out either in port terminals before natural gas is transported via gas lines or directly before the use of natural gas. The exploitation of cold from LNG is quite limited at present. Most of the available cold is wasted during the regasification process when LNG is heated up by water or ambient air. Inefficient use of cold temperature streams reduces the overall efficiency of this primary energy source and leads to greater emissions. Promising ways of utilizing cold from LNG in the regasification process should be explored and implemented (Pospíšil et al., 2019). For LNG that is ultimately combusted for electricity, Jordaan et al. (2022) find that deploying mitigation options can reduce global emissions from gas-fired power by 71 percent with carbon capture and storage, CH_4 abatement, and efficiency upgrades contributing 43 percent, 12 percent, and 5 percent, respectively—this suggested mitigation falls within national responsibilities, except an annual 20.5 $MtCO_2e$ of ocean transport emissions.

Roman-White et al. (2021) note that for LNG, harmonized data collection and reporting would build confidence in supplier claims about LCA emissions, enabling comparisons between natural gas supply chains and supporting climate goals for all participants in the supply chain. This could stimulate a virtuous cycle of demand for GHG accounting and reduction and provision of more granular, company-specific emissions estimates.

MacKinnon et al. (2018) demonstrate that natural gas-fired power generation and the natural gas system could play several important roles in supporting sustainable energy strategies over time that can achieve societal GHG reduction goals and help the transition to renewable sources. Natural gas generation can support transitions to renewable resources 1) by use in advanced conversion devices to provide complementary grid services efficiently and with very

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low emissions to maximize the benefits of intermittent renewable resources (e.g., running a natural gas compression system during peak renewables production), and 2) natural gas generation and the existing natural gas infrastructure can support the use of renewable natural gas with high energy and environmental benefits.

According to Stern (2022), three major requirements for creating credible measuring, reporting, and verification of CH_4 emissions are 1) to move measurement and reporting of CH_4 emissions from standard factors—either engineering-based or from EPA data—to empirical (Tier 3) measurements, and to reconcile bottoms-up (ground level) and top-down (satellite/aircraft/drone) observations; 2) to ensure that data measurement and reporting has been verified and certified by accredited bodies; and 3) to require asset-level emissions data to be transparent and publicly available. Failure to do so on grounds of commercial confidentiality risks being interpreted as evidence that the data is not credible.

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3 AIR QUALITY

The natural gas supply chain contributes to air pollution in several ways including 1) the leaking, venting, and combustion of natural gas during production and 2) the combustion of other fossil fuel resources or other emissions during associated operations (e.g., extraction, transportation, downstream combustion). Emissions sources include pad, road, and pipeline construction; well drilling, completion, and flowback activities; and natural gas processing and transmission equipment such as controllers, compressors, dehydrators, pipes, and storage vessels. Pollutants include, most prominently, CH_4 and volatile organic compounds (VOCs)—of which the natural gas industry is one of the highest-emitting industrial sectors in the United States—in addition to nitrogen oxides, sulfur dioxide (SO_2), and various forms of other hazardous air pollutants (HAPs) (Congressional Research Service [CRS], 2020). Pollutants are described in detail below (CRS, 2020):

- CH_4 is the principal component of natural gas is a precursor to ground-level ozone formation (i.e., “smog”).
- NOx is a ground-level precursor. Significant amounts of NOx are emitted during the combustion of natural gas and other fossil fuels (e.g., diesel). The combustion of natural gas occurs when it is flared during drilling and well completions and used to drive the various compressors that move products through the system. Combustion also occurs in engines, drills, heaters, boilers, and other production equipment.
- VOCs are a ground-level ozone precursor. The crude oil and natural gas sector is currently one of the largest sources of VOC emissions in the United States, accounting for approximately 20 percent of man-made VOC emissions nationwide (and representing almost 40 percent of VOC emissions released by stationary sources). VOCs—in the form of various hydrocarbons—are emitted throughout a wide range of natural gas operations and equipment. The interaction among VOCs, NOx, and sunlight in the atmosphere contributes to the formation of ozone.
- SO_2 is emitted from crude oil and natural gas production and processing operations that handle and treat sulfur-rich, or “sour,” gas.
- HAPs, also known as air toxins, are those pollutants that are known or suspected to cause cancer or contribute to other serious health effects including reproductive issues and birth defects. Of the HAPs emitted from natural gas systems, VOCs are the largest group and typically evaporate easily into the air. The most common HAPs produced from natural gas systems are n-hexane and benzene, toluene, ethylbenzene, and xylenes (BTEX) compounds. Some natural gas reservoirs may also contain high levels of hydrogen sulfide (H_2S). HAPs are found primarily in natural gas itself and are emitted from equipment leaks and during processing, compressing, transmission, distribution, or storage operations. HAPs are also a byproduct of incomplete fuel combustion and may be components in various chemical additives.

3.1 UPSTREAM PRODUCTION AND HYDRAULIC FRACTURING

The venting of natural gas during extraction and processing is a key source of VOC emissions. Similar to CH_4, VOCs are a naturally occurring constituent of natural gas and react with other pollutants to produce ground-level ozone.

Emissions of VOCs and CH_4 are lower for offshore conventional production compared to other types of natural gas types because offshore platforms generally have higher production rates helping to justify capital expenditures on loss reduction technologies, which help to prevent unnecessary venting.[f] Another source of VOC emissions during upstream operations is venting from condensate storage tanks, which occurs in regions with wet gas.[g]

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The combustion of natural gas in compressors and gas processing equipment produces NOx and carbon monoxide (CO). Similarly, the combustion of diesel in drilling equipment produces NOx and CO, as well as significant quantities of SO_2 emissions. Beyond VOCs, CH_4, NOx, CO, and SO_2 emissions, upstream processes can also produce aliphatic hydrocarbons, (e.g., C2–C5), alkanes, VOCs (e.g., BTEX), H_2S, n-hexane, and formaldehyde, which can contaminate ambient air (Wollin et al., 2020).

Elliott et al. (2017) estimates that up to 143 air contaminants can be released during hydraulic fracturing. The International Agency for Research on Cancer generates hazard assessments for only 20 percent of these identified contaminants. Twenty of these air contaminants are known carcinogens. Other air contaminants are generated by the peripheral plant components. These include particulate matter, NOx, precursors of ozone and polycyclic aromatic hydrocarbons (Wollin et al., 2020).

The following activities are known to contribute to air contamination at oil or gas drilling sites:

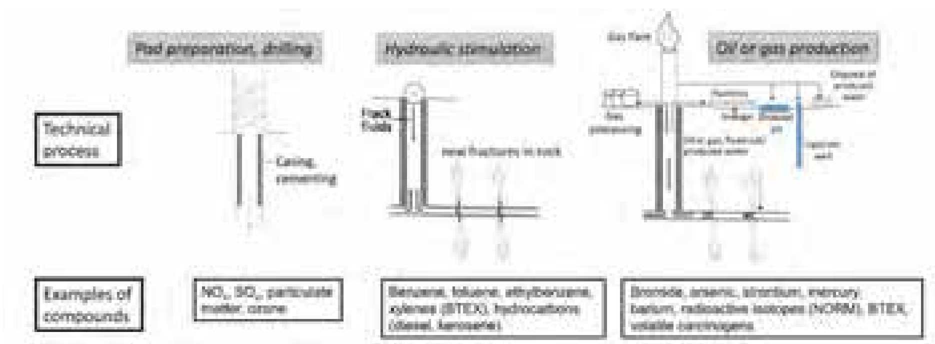
- Preparation of the drilling site including road connections
- Drilling of the well
- Truck traffic for delivery and disposal of materials
- Removal of acid gases and water from gas; separation of natural gas from other hydrocarbons
- Operation of compressor stations to enable the transport of natural gas into transport pipelines
- Preprocessing of crude oil prior to refinery

Exhibit 3-1 illustrates the supply chain for natural gas where each of these activities occurs (Wollin, 2020).

[f] There are no technological barriers to applying such emission reduction technologies to shale gas or other sources of natural gas.f

[g] When natural gas is retrieved, it can be considered wet or dry. Dry natural gas is at least 85 percent methane, but often more. Wet natural gas contains some methane, but also contains liquids such as ethane, propane or butane. The more methane natural gas contains, the "dryer" it is considered.

Exhibit 3-1. Illustration of supply chain steps where upstream air pollution occurs



Permission pending from Wollin et al. (2020)

NOx and SOx emissions have been reported to be higher during the development of the drilling site compared to during the production phase (Wollin et al., 2020). Similar observations have been made for particulate matter (PM) (e.g., PM2.5 and PM10). Analysis of shale gas production sites in North Texas showed an increase in ozone concentrations by 8 percent at natural gas production sites compared to control sites (Wollin et al., 2020).

Indirect energy consumption can also affect the air quality profile of gas extraction technologies. If the development or operation of a natural gas well uses grid electricity, then the fuel mix of the electricity grid will affect the life cycle performance of the well. The indirect air quality impacts of electricity consumption depend on the fuel mixes and combustion characteristics of power plants that compose a regional electricity grid.

A critical aspect concerning emissions from hydraulic fracturing processes is that several of the organic toxic compounds that are emitted are not regulated. EPA's National Ambient Air Quality Standards only places limits on six Criteria Air Pollutants including CO, ozone near the surface, NOx, PM, SO_2, and lead. Since the National Ambient Air Quality Standards do not place limits on nor consider the effects of organic compounds beyond those listed previously, EPA's Integrated Risk Information System is frequently used to identify and characterize the health hazards of other compounds. Unlike the National Ambient Air Quality Standards, the Integrated Risk Information System does not place any legal restrictions on the release of the compounds it provides data on. As such, national regulations for the breadth of air emissions released during hydraulic fracturing are insufficient. Exhibit 3-2 offers a perspective on non-GHG air pollutant by supply chain step or equipment.

Exhibit 3-2. Perspective of non-GHG air pollutant by supply chain step or equipment

Source	Air pollutant				Data quality
	NO_X	VOC	PM	Other toxic substances	
Well development					
Drilling rigs	•	·	•	•	Medium
Frac pumps	•	·	•	•	Medium
Truck traffic	•	·	•	•	Medium
Completion venting		•		•	Poor
Frac ponds		·			Poor
Gas production					
Compressor stations	•	•	·	•	Medium
Wellhead compressors	·	·	·	·	Medium
Heaters, dehydrators		·	·	·	Medium
Blowdown venting		·		·	Poor
Condensate tanks		•		·	Poor
Fugitives				·	Poor
Pneumatics		·		·	Poor

• Major source, · minor source

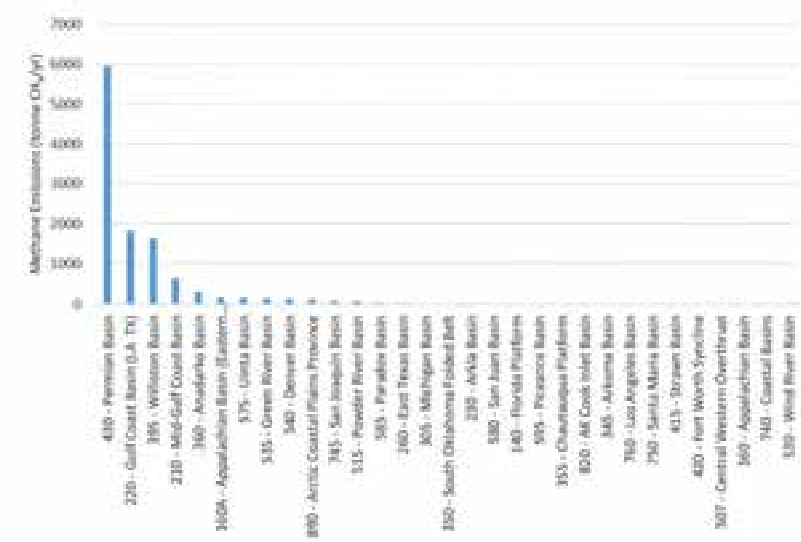
Permission pending from Wollin et al. (2020)

McMullin et al. (2018) analyzed exposure to VOCs emitted during hydraulic fracturing in Colorado. They identified 56 different VOCs that were emitted during hydraulic fracturing using data they compiled from 47 existing air monitoring devices that measured these VOCs at 34 different locations across the region.

Plant et al. (2022) used airborne sampling to measure flare efficiency[h] in three major gas production regions in the United States. They found that both unlit flares and inefficient combustion contribute comparatively to ineffective CH_4 destruction, with flares effectively destroying only 91.1 percent (90.2–91.8 percent; 95 percent confidence interval) of CH_4 emissions. Other emissions from flaring can include carbon particles (soot), unburned hydrocarbons, CO, partially burned and altered hydrocarbons, NOx, and (if sulfur containing material such as H_2S or mercaptans is flared) SO_2. The combustion products of flaring at natural gas production and processing sites specifically include CO_2, CH_4, and N_2O. Exhibit 3-3 illustrates the annual methane emissions from flaring for U.S. production basins (NETL, 2020).

[h] The flare efficiency is a measure of the effectiveness of the combustion process to fully oxidize the fuel. When inefficiencies occur, unburned fuel, CO, and other products of incomplete combustion (e.g., soot, VOCs, etc.) are emitted into the atmosphere.

Exhibit 3-3. Annual CH_4 emissions from flaring for U.S. production basins



3.2 MIDSTREAM TRANSPORT EMISSIONS

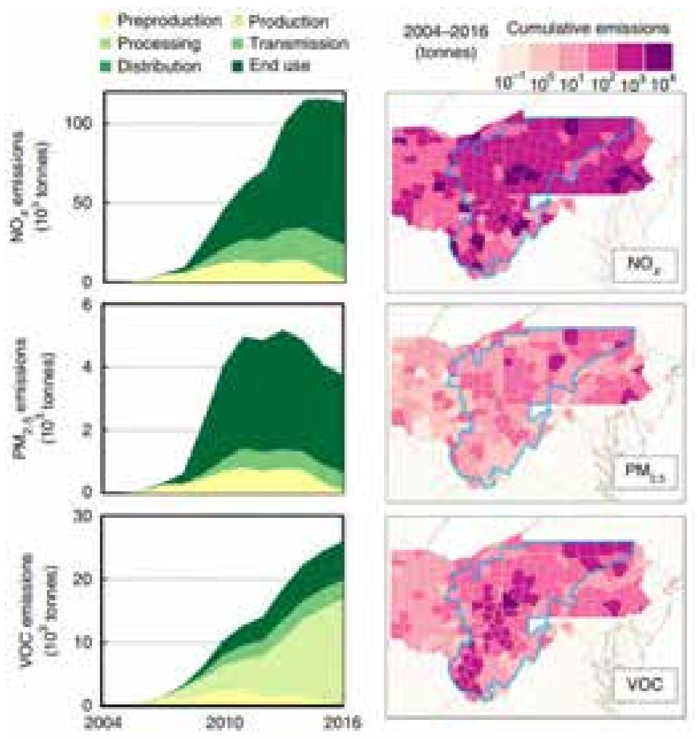
While the presence of HAPs in unprocessed, upstream natural gas has been documented, little has been published on their presence in the midstream segments of the natural gas supply chain. Nordgaard et al. (2022) systematically evaluated publicly available, industry-disclosed HAP composition data from natural gas infrastructure applications submitted to FERC between 2017 and 2020. These applications covered 45 percent of the U.S. onshore natural gas transmission system (as measured by pipeline miles). Given that reporting HAP composition data is not required by FERC, only 49 percent of approved projects disclosed their HAP composition data to FERC. Of the applications that did disclose their HAP composition data, HAP concentrations were typically reported as higher for separator flash gas and condensate tank vapor compared to liquefied natural gas and transmission-grade natural gas, with mean benzene concentrations of 1106, 7050, 77, and 37 parts per million, respectively.

Nordgaard et al. (2022) also identified one pipeline operator that reports real-time HAP concentrations for natural gas at five pipeline interconnection points. Similar to the FERC applications, this operator reported BTEX and H_2S as present in the pipelines used to transport their natural gas. Notably, mercury was also reported as detectable in 14 percent of real-time natural gas measurements but was not reported in any FERC applications. Because current transmission infrastructure releases natural gas during uncontrolled leaks, loss of containment events, and routine operations (e.g., blowouts and compressor station blowdowns) having access to HAP composition data may be critical for conducting both air quality and health-focused evaluations of natural gas releases.

3.3 End-Use Processes

Mayfield et al. (2019) performed an analysis of the environment impacts associated with the shale gas boom in the Appalachian Basin and found the majority (61 percent) of VOC emissions from the natural gas supply chain can be largely attributed to upstream processes and are spatially concentrated in counties with the highest cumulative production. Upstream processes contribute the most to total NOx (67 percent) and PM2.5 (73 percent) emissions across the natural gas supply chain; NOx and PM2.5 emissions are relatively evenly distributed across counties (Mayfield et al., 2019). Exhibit 3-4 presents annual NOx, PM2.5, and VOC emissions from the natural gas supply chain within Pennsylvania, Ohio, and West Virginia, along with the spatial distribution of cumulative NOx, PM2.5, and VOC emissions by county between 2004 and 2016. It is important to note that the blue lines delineate shale gas-producing counties (Mayfield et al., 2019).

Exhibit 3-4. Annual (left graphs) and cumulative (right graphs) (2004–2016) NOx, PM2.5, and VOC emissions from natural gas supply chain within Pennsylvania, Ohio, and West Virginia



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4 Water Use and Quality

The literature describes the treatment and management of wastewaters as the central environmental concern regarding natural gas production. Especially in the eastern regions of the United States where—although water is abundant—significant natural gas production has been occurring. In the western part of the United States, persisting dry climates limit the use and availability of freshwater for natural gas production. Specifically freshwater availability for drilling and hydraulic fracturing.

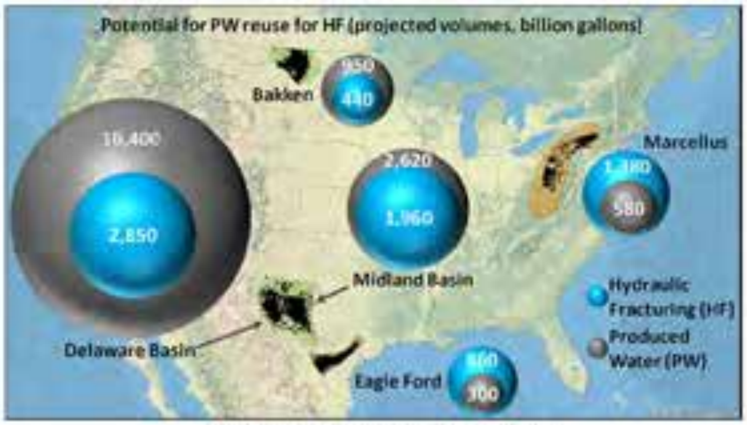
Gallegos et al. (2015) estimate that drilling and hydraulically fracturing a shale gas well can consume 2.6–9.7 MM gallons (gal) of water (Gallegos et al., 2015). From 2015 to 2014, unconventional shale gas in the United States used 187 billion (B) gal of water. From 2012 to 2014, the average use for hydraulic fracturing was 30.6 B gal annually. Additionally, Gallegos et al. (2015)'s integrated data from 6–10 years of operations suggest 212 B gal of combined flowback and produced water are produced from unconventional shale gas and oil formations. While the hydraulic fracturing revolution has increased water use for natural gas production across the United States, the water use and produced water intensity of hydraulic fracturing is lower than the water use and produced water intensity of other energy extraction methods and represents only a small fraction of total industrial water use nationwide (Kondash and Vengosh, 2015). However, even the smallest local or seasonal water supply shortages can cause issues.

Water quality can also be impacted by natural gas production processes if water is inadequately managed or by the use of fracturing chemicals both on the surface—before injection and after flowback—and in produced water. Subsurface water quality impacts can result from the migration of fracturing fluids, formation waters, and CH_4 along well bores and through rock fracture networks. Management and disposal efforts increasingly include efforts to minimize water use through recycling and re-use of fracturing fluids, in addition to treatment and disposal of wastewater through deep underground injection.

The shale boom has made energy more available and affordable globally but has also contributed to environmental concerns surrounding the use of water. Scanlon et al. (2020) analyze the water-related sustainability of energy extraction. They focus on meeting the rapidly rising water demand for hydraulic fracturing and managing growing volumes of water co-produced with oil and gas. They analyze historical (2009–2017) volumes of water in ~73,000 wells and projected future water volumes in major U.S. unconventional oil and gas plays. Their results show a marked increase in fracking water use, depleting groundwater resources in some semiarid regions (Scanlon et al., 2020).

Water issues related to both fracking water demand and produced water supplies may be partially mitigated through reuse of produced water for fracking of new wells. As shown in Exhibit 4-1, projected produced water volumes exceed fracking water demand in semiarid Bakken (2.1×), Permian Midland (1.3×), and Delaware (3.7×) oil plays, with the Delaware oil play accounting for ~50 percent of the projected U.S. oil production (Scanlon et al., 2020). Therefore, water issues could constrain future energy production, particularly in semiarid oil plays.

Exhibit 4-1. Map showing ratio between produced water and fracking water demand for major shale basins



Permission pending from Scanlon et al. (2020)

4.1 Water Use for Unconventional Natural Gas Production

Most of the water used for unconventional natural gas production is used for drilling for hydraulic fracturing. For example, of the total water used by the shale gas industry, hydraulic fracturing is estimated to account for about 89 percent, drilling about 10 percent, and infrastructure the remainder (<1 percent) (Hayes and Severin, 2012). Water is also the main component of the fluids used for hydraulic fracturing, making up approximately 99 percent of the total volume.

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Reporting from Gallegos, et al. (2015) suggests hydraulic fracturing uses 2.6–9.7 MM gal of water per well drilled, while the American Petroleum Institute (API) (2023) indicates that the average hydraulically fractured well uses 4 MM gal of water. As water is a scarce resource, it is important to consider the potential environmental impacts of using water from different sources (e.g., ground water, surface water). If available surface water is used to support natural gas production, then the ecosystems that rely on this water could be harmed. Significant groundwater withdrawals can also permanently deplete aquifers.

The process of hydraulic fracturing uses large volumes of water mixed with chemicals and proppant (sand) to fracture low-permeability shale and tight oil rocks, allowing the extraction of hydrocarbons to occur. Despite the higher water intensity (the amount of water used to produce a unit of energy; for example, liters per gigajoules) compared to drilling conventional vertical oil and gas wells, overall water withdrawals for hydraulic fracturing is negligible compared to other industrial water uses on a national level (Vengosh et al., 2014; Jackson et al., 2014; Kondash, Albright, and Vengosh, 2017; Kondash and Vengosh, 2015). On a local scale, however, water use for hydraulic fracturing can cause conflicts over water availability, especially in arid regions such as western United States, where water supplies are limited (Scanlon, Reedy, and Nicot, 2014; Scanlon et al. 2017; Nicot and Scanlon, 2012; Ikonnikov et al., 2017; Kondash, Lauer, and Vengosh, 2018).

4.1.1 Water Consumption Impacts

Water use for hydraulic fracturing and wastewater production in major shale gas and oil producing regions increased between 2011 and 2016, with water use per well increasing by up to 770 percent—with flowback and produced water volumes generated within the first year of production increasing up to 550 percent. The water-use intensity (that is, normalized to the energy production) increased in all U.S. shale basins, except the Marcellus shale basin over this period (Kondash, Lauer, and Vengosh, 2018).

Water consumption per shale gas well can vary due to four conditions:

- *Geology*: maturity of the shale and formation depth, thickness, and lateral extent
- *Technology*: horizontal or vertical drilling, water recycling
- *Operations*: operator decisions, availability of nearby freshwater
- *Regulatory*: requirements for use and treatment of water

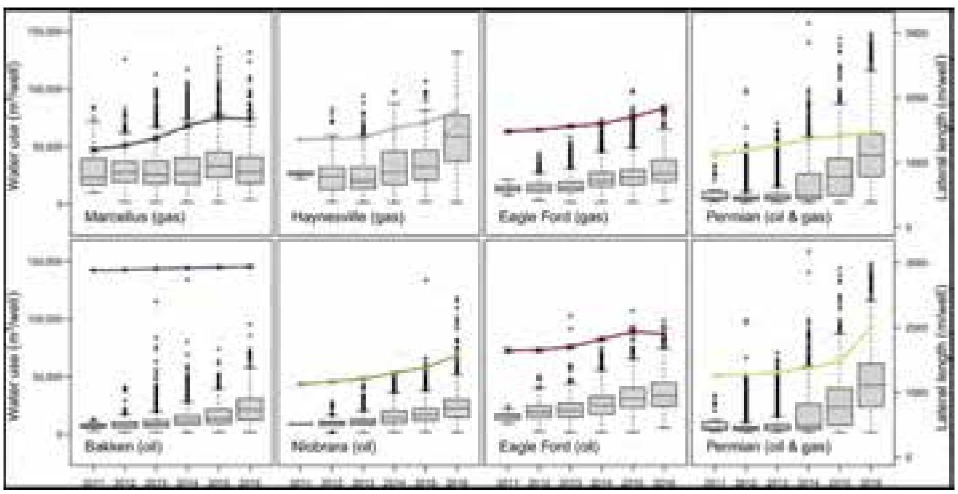
During 2009–2017, ~73,000 wells, or an aggregated total lateral length of ~440 × 106 ft (134,000 km), were drilled in the eight studied plays, equivalent to ~3× the Earth's circumference (40,000 km). Dieter et al. (2018) find that to fracture the rock along that length, a total of ~480 B gal of water was used, equivalent to ~0.1 percent of the U.S. 2015 total water withdrawal or almost two days of freshwater withdrawal (280 B gal/day). Exhibit 4-2 shows the water consumption for hydraulic fracturing, the amount of produced water used and oil and gas outputs from 9 major plays in the United States (Scanlon et al., 2020). The Eagle Ford play has used 173 B gal of combined hydraulic fracturing and produced water, at nearly a 1.83 ratio of freshwater:produced water and the Marcellus has a freshwater:produced water ratio of 5.83. Other plays use more produced water than freshwater, like Bakken, Delaware, and Barnett, where the ratios of produced water to freshwater are 1.83, 2.21, and 2.11 respectively.

Exhibit 4-2. water use in nine shale plays in the U.S.

Play	Total Length (10^6 ft)	Median Well Length (ft)	Number of Wells	Hydraulic Fracturing Water (10^9 gal)	Produced Water (10^9 gal)	Oil (10^9 gal)	Gas (10^9 gal of oil equivalent)
Bakken	114	9,580	12,036	49	75	100	22
Eagle Ford	95	6,061	17,366	112	61	103	78
Midland	49	8,575	6,461	79	44	30	14
Delaware	36	5,272	7,070	51	113	40	26
Marcellus	51	7,139	9,651	70	12	3	214
Niobrara	21	7,438	3,842	21	5	14	11
Barnett	27	5,241	7,453	35	74	1	111
Haynesville	15	6,270	3,215	30	16	0.03	107
Fayetteville	21	6,386	4,717	24	-	-	55

Exhibit 4-3 from Kondash et al. (2018) indicates that parallel to the increase in lateral lengths of the horizontal wells and hydrocarbon extraction yields through time, the water use has also increased. The relative increase in lateral length (4–60 percent) was, however, significantly lower than the increase in water use (14–770 percent). When water use per well is normalized to the length of lateral section of the horizontal well, in almost every case among oil producing regions, an increase in water use per length of the horizontal well is observed. This pattern is most evident in the Permian region, where water use increased from 4.4 cubic meter (m^3) per meter in 2011 to 29.3 m^3 per meter in 2016 for gas-producing wells, and from 3.9 m^3 per meter in 2011 to 21.1 m^3 per meter in oil-producing wells. In all cases with the exception of Marcellus in 2016, the flowback and produced (FP) water generation was also increasing through time, with particularly higher rates after 2014.

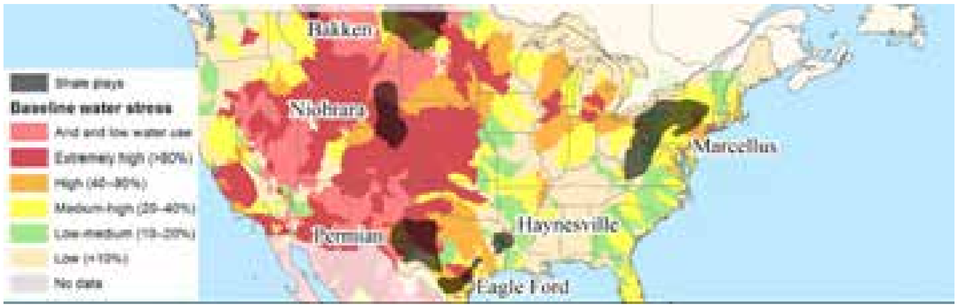
Exhibit 4-3. Water usage and lateral length by shale play



Used with permission from Kondash et al. (2018)

Kondash et al. (2018) also illustrate water conditions where the major plays across the United States are located, see Exhibit 4-4. The Bakken, Niobara, Permian and Eagle Ford plays are all located in arid to extremely dry climates where drought conditions have persisted for many years.

Exhibit 4-4. Baseline water stress and location of shale plays



Permission pending from Kondash et al. (2018)

4.1.2 Water Quality

Concerns have been raised about potential public health effects that may arise if hydraulic fracturing-related chemicals were to impact drinking water supplies. The chronic oral toxicity values—specifically, chronic oral reference values (RfVs) for noncancer effects, and oral slope factors (OSFs) for cancer are available for the list of 1,173 chemicals EPA identified as "associated with hydraulic fracturing." These include 1,076 chemicals used in hydraulic fracturing fluids and 134 chemicals detected in the flowback or produced waters from hydraulically fractured wells.

EPA compiled RfVs and OSFs for these chemicals using six different governmental and intergovernmental data sources. Ninety (8 percent) of the 1,076 chemicals used in hydraulic fracturing fluids and 83 (62 percent) of the 134 chemicals found in flowback/produced water had a chronic oral RfV or OSF reported in at least one or more of the six data sources used. Thirty-six of the chemicals used in hydraulic fracturing fluids have been measured in at least 10 percent of the hydraulically fracted wells drilled nationwide (identified from EPA's analysis of the FracFocus Chemical Disclosure Registry 1.0). Eight of these 36 chemicals (22 percent) had an available chronic oral RfV. The lack of chronic oral RfVs and OSFs for the majority of these chemicals highlights the significant knowledge gap that exists to assess the potential human health hazards associated with hydraulic fracturing (Yost et al., 2016).

Ecological risks to surface waters are present throughout the well life cycle and may manifest themselves differently locally compared to regionally. These risks can also vary temporally, as development activity like surface water withdraw may only result in a single, brief impact, while the network of roads required for accessing the well pad could increase erosion and sediment runoff for years. Previous work identified the primary risks to surface water quality as sediment runoff from devegetation, leakage and spillage of chemicals into surface waters, unsustainable water withdrawal, landscape fragmentation, and insufficient treatment of oil and gas wastewater prior to discharge (Krupnick, Gordon, and Olmstead, 2013; Slonecker et al., 2012; Drohan et al., 2012; Kiviat, 2013). Unfortunately, few sites exist where baseline environmental monitoring occurred prior to hydraulic fracturing operations commencing (McBroom, Thomas, and Zhang, 2012). This greatly complicates efforts to precisely quantify impacts of hydraulic fracturing, particularly if these operations are occurring in watersheds with preexisting anthropogenic influence and a host of existing ecological stressors (Mauter et al., 2014).

The surface water risks and impacts associated with unconventional resource development will vary significantly by region (Clements, Hickey, Kidd, 2012). To date, those in the Marcellus region have been examined most extensity. This scrutiny has been motivated by the nexus of regionally specific risk drivers such as high gradient terrains that could lead to increased erosion, an abundance of small streams, highly variable in-streamflow rates, and the high salinity of produced water in the Marcellus. Moreover, during the early development of the Marcellus shale in PA, the state permitted the disposal of hydraulic fracturing brines in municipal wastewater treatment plants. To reduce the human and environmental impacts associated with this practice, energy and production companies have adopted a moratorium on the disposal of produced water in wastewater treatment plants in PA (Wilson and Van Briesen, 2012; Wilson, Wang, and Van Briesen, 2013; Warner et al., 2013; Wilson and Van Briesen, 2013; Renner, 2009).

In the Marcellus and Fayetteville plays, more than 80 percent of the active gas wells are located within 300 meters of drainage areas and recent studies have reported a positive correlation between total suspended solids and the density of upstream gas wells in both the Marcellus and Fayettville.

4.1.3 General Guidelines for Leading Regulatory Practices on Water Sourcing

Increasing demand for water for drilling and hydraulic fracturing shale gas plays has driven operators to seek supplemental sources of water, and alternatives to local freshwater supplies. Potential alternatives include industrial wastewater, water treatment plant outflows, abandoned mine waters, saline groundwater, and reuse of produced waters.

Ceres (Freyman, 2014) developed a set of guidelines based on gathering the experiences, best practices, and issues throughout the U.S. shale industry. The following is a list developed by Ceres that describes the leading best practices for water sourcing:

- Catalogue the consumptive water use from hydraulic fracturing operations, including sources of water used and the amounts recycled.
- Require information on how operators are planning to manage wastewater streams including final disposal of water.
- Create integrated management structures for joint oversight of ground and surface water (as some are now proposing in British Columbia).
- Realize that higher disclosure requirements alone will not solve water sourcing impacts and risks and must be accompanied by proactive water management plans that include monitoring and enforcement components.
- Ensure that water-sourcing oversight is independent from the department granting oil and gas permits to minimize conflicting mandates and objectives.

- Create systems of incentives and/or mandate requirements to encourage recycling and non-freshwater use.
- Implement measures to prevent invasive species transfers.
- Provide more resources to map and monitor groundwater resources, including remote aquifers and brackish water resources, across North America.
- Reduce reliance on aquifer exemptions and create incentives to minimize use of deep well injection sites.

4.2 Regulations

Although EPA is generally responsible for water quality by regulating underground injection, hydraulic fracturing is exempt from federal regulation under the SDWA (except when diesel fuel is included in the fluid or there is an imminent and substantial danger to the health of persons). As a result, the responsibility to protect drinking water from hydraulic fracturing activity falls primarily on the states (Zirogiannis et al., 2016).

Rapidly growing demand for water for hydraulic fracturing has challenged water resource managers in many regions. Many state and regional water plans have quickly become outdated as demand for water for shale oil and gas development increases and expands into new regions (Collier, 2011).

States or provinces have the primary responsibility for permitting oil and gas development and related water sourcing, but there is currently significant disparity in their approaches to regulating shale water requirements and associated impacts. A recent study by Resources for the Future (RFF) looked at regulations relevant to shale gas energy development and found markedly different water withdrawal policies across 30 of the states they surveyed, including those with major shale energy development (Exhibit 4-5, states with major shale energy development are outlined in yellow). The study found that for most of the 26 states with any water withdrawal permitting requirements, only half require permits for all withdrawals. Several states do not require permits at all, but only disclosure of water use over a certain threshold, as represented by the light purple states (Freyman, 2014).

In addition, some states and provinces exempt the oil and gas industry from permitting requirements for water withdrawals, including the following:

- Kentucky, which exempts the industry from both surface and groundwater reporting
- Texas, which requires permits for surface water withdrawals, but generally not for groundwater

Exhibit 4-5. Water withdrawal regulations by state

Used with permission from Richardson et al. (2013)

In many cases, states where hydraulic fracturing is taking place have had to set their own regulations. The following is a list of examples of state-based water regulations related to hydraulic fracturing. This list is not exhaustive.

4.2.1 Pennsylvania

Pennsylvania is leading the way in requiring strong disclosure of freshwater and recycled water use during hydraulic fracturing. Within 30 days after completion of a well, the operator must submit a completion report to the Pennsylvania Department of Environmental Protection (PADEP). That report must include a stimulation record, which provides technical details associated with hydraulic fracturing, and list water resources that were used under an approved water management plan, including volume of water used from each source (25 Pa. Code § 78.122(b)(6); 25 Pa. Code § 78.122(b)(6)(vi)). Operators must also disclose the volume of recycled water used during well drilling (25 Pa. Code § 78.122(b)(6)(vii)). The PADEP then reviews plans and approves them provided that water withdrawals:

- Do not adversely affect the quantity or quality of water available to other users of the same water sources.
- Protect and maintain the designated and existing uses of water sources.
- Do not cause adverse impact to water quality in the watershed considered as a whole.
- Are mitigated through a reuse plan for fluids that will be used to hydraulically fracture wells (58 Pa. Cons. Stat § 3211(m)(2)).

Other PA water regulations include the following:

- § 78a.15: If the proposed limit of disturbance of the well site is within 100 ft measured horizontally from any watercourse or any high quality or exceptional value body of water or any wetland 1 acre or greater in size, the applicant shall demonstrate that the well site location will protect those watercourses or bodies of water.
- § 78a.51. Protection of water supplies
    - A well operator who affects a public or private water supply by pollution or diminution shall restore or replace the affected supply with an alternate source of water adequate in quantity and quality for the purposes served by the supply as determined by the Department.
    - A landowner, water purveyor or affected person suffering from pollution or diminution of a water supply as a result of oil and gas operations may so notify the Department and request that an investigation be conducted. Notice shall be made to the appropriate Department regional office or by calling the Department's Statewide toll-free number at (800) 541-2050. The notice and request must include the following:
- Require operators to demonstrate how they will prevent damage to aquatic life during water withdrawals.[i]

4.2.2 Colorado

The Air Pollution Control Division issued revised versions of Operating and Maintenance Plan Templates for Produced Water Storage Tanks.

In January 2013, the Colorado Oil and Gas Conservation Commission (COGCC) approved the most rigorous statewide mandatory groundwater sampling and monitoring rules in the United States. The purpose of Rule 609, "is to gather baseline water quality data prior to oil and gas development occurring in a particular area, and to gather additional data after drilling and completion operations" (COGCC, 2020).

Wells are constructed with multiple layers of steel casing and cement; COGCC rules require the following specifications for each well:

- In the water-bearing and hydrocarbon zones, the casing is cemented into place, and cement fills the void space between each layer of casing.
- At least two layers of steel casing and cement are in place from the ground surface to the lowest point of the freshwater aquifer.
- In the hydrocarbon formation, several thousand feet below the aquifer in most cases, there is at least one layer of steel and cement, and the hydrocarbons move through the inner-most casing to the surface.

[i] See section C.6 titled "Withdrawal Impacts Analysis," in the PADEP Water Management Plan For Unconventional Gas Well Development Example Format (2013).

Colorado requires disinfection of water suction hoses when water withdrawals occur in cutthroat trout habitats to avoid transfer of invasive or harmful species (Colo. Code Regs. § 404-1:1204, Westlaw 2012.).

4.2.3 Texas

The RRC (the agency that regulates the state's oil and gas industry) recently amended its rules to make it easier to recycle wastewater streams from hydraulic fracturing operations. Operators no longer need permits to recycle water and can even accept water from other areas or companies, as long as the recycling takes place on land leased by the operator so that oversight can be maintained. This new rule also allows operators to turn around and sell the water to other operators (Osborne, 2013).

4.2.4 Ohio

Ohio's freshwater and recycled water use rules require operators to identify each proposed source of groundwater and surface water that will be used (Ohio Rev. Code §1509.06(A)(8)(a).). Ohio does not, however, require post-drilling disclosure of actual volumes of freshwater and recycled water used.

4.3 Current Research and Development and Analysis

NETL is performing advanced remediation technology research to better manage effluent water from energy production. The Water Energy Effluent Management Program aims to ensure that American water is affordable, reliable, sustainable, and resilient for energy use, and to reduce the environmental impact of freshwater consumption for energy production related to oil and gas operations (and coal combustion) as well as to reduce the volume of produced water disposal during oil and gas activities by:

- Improving treatment methods for produced water constituents that are both hard and costly to treat.
- Increasing the beneficial use possibilities for treated produced water outside of the oil and gas industry.
- Reducing environmental impacts related to produced water such as freshwater consumption in water scarce regions and induced seismicity.
- Characterizing produced water and energy effluent waters to identify potential resources such as critical minerals that could be harvested for uses within other industries.

To support this vision, the program aspires to reduce the environmental impact of freshwater consumption for energy production related to oil and gas operations and coal combustion as well as to reduce the volume of produced water disposal during oil and gas activities. The research areas include the following:

- Treatment technologies – developing effective and cost-effective technologies and treatment trains to treat produced water

- Beneficial use technologies – increasing the likelihood that treated produced water can be utilized in other industries besides oil and gas
- Resource characterization – characterization of produced water constituents for potential harvesting for other industrial uses

A goal of the program is to engineer water composition to improve imbibition into the formation matrix with ionic modification, surfactants, and nanoparticles, which can change the wettability of carbonate rocks toward more water-wet conditions under which water can imbibe into the matrix and displace oil into the fractures. The modified water composition will be injected to improve oil recovery from the carbonate matrix in fractured reservoirs. The result can increase production from the well with no increase in the amount of water, chemicals, proppants, and energy required. This translates to minimized air emissions and other environmental impacts associated with production of a unit volume of oil and gas.

Currently, Water Energy Effluent Management Program has four existing projects:

- Develop effective treatment technologies to treat produced water via energy- and cost-efficient approaches for use within the oil and gas industry (2 projects)
- Develop advanced or novel membrane specific technologies for treatment of produced water (1 project)
- Developing methods to characterize and extract rare earth elements or critical minerals from produced water (1 project)

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5 INDUCED SEISMICITY

Induced seismicity is ground motion (earthquakes) caused by human activities. Earthquakes have been detected in association with both oil and natural gas production, underground injection of wastewaters (i.e., wastewater disposal), and hydraulic fracturing (Rubinstein and Mahani, 2015). Each these processes involves injecting large volumes of foreign fluids at various pressures into underground formations.[j] Earthquakes from induced seismicity have happened in multiple countries, including in the United States (Shultz et al., 2020).

5.1 IMPACTS FROM INDUCED SEISMICITY AND ENERGY TECHNOLOGIES

The term seismic activity is generally used to describe vibrations of mechanical energy that pass through the earth, much like sound waves vibrate through the atmosphere. The seismic activity of a region is defined by the frequency, kind, and magnitude of earthquakes experienced in the region during a given period. The National Earthquake Information Center (NEIC) is the entity responsible for determining, as rapidly and as accurately as possible, the location and size of all significant earthquakes that occur worldwide. At present, the NEIC locates and publishes detailed data on the 30,000 “most significant” earthquakes that occur in each year (USGS, 2023).

While millions of earthquakes occur each year not all are felt at the surface. Earthquakes with magnitudes of 2.0 or less generally cannot be felt at the surface by people, while earthquakes with magnitudes greater than 3.0 tend to produce noticeable shaking. Earthquakes with magnitudes greater than 5.0 are felt at the surface and have the potential to cause structural damage to buildings and property. Most earthquakes that do occur are in response to natural, yet sudden slips and shifts of large masses of rock along geologic faults.

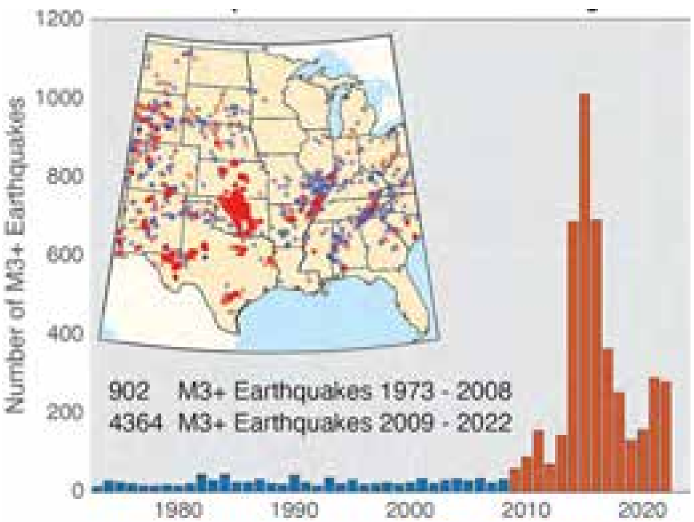
The seismicity rate in the central and eastern United States increased 40-fold within the past decade predominantly as a result of human activities (Ellsworth, 2013; van der Baan and Calixto, 2017). This recent increase in seismicity rate in the central and eastern United States has largely been attributed to large-volume wastewater disposal wells injecting fluids into deep sedimentary formations (e.g., Keranen et al., 2014; Rubinstein and Mahani, 2015). Other human activities, including hydraulic fracturing (Skoumal, Brudzinski, and Currie, 2015) and carbon sequestration (e.g., Kaven et al., 2015), have induced seismicity to a lesser extent in the central and eastern United States (Skoumal et al., 2020).

Exhibit 5-1 presents the annual number of earthquakes (with a magnitude of 3.0 or larger) occurring in central and eastern areas of the United States for 1973–2022. Many of these earthquakes have taken place in areas where hydraulic fracturing has been and is actively occurring (e.g., Oklahoma) (USGS, 2022). Between 1973 and 2008, approximately 25 earthquakes of magnitude three or greater occurred on average annually. Since 2009, at least 58 earthquakes of this same size (magnitude of 3.0 or larger) have occurred annually, and at

[j] Hydraulic fracturing involves injecting large volumes of fluids into the ground to release trapped oil and natural gas. Wastewater from oil and gas production, including shale gas production, is typically disposed of by being injected at relatively low pressures into extensive formations that are specifically targeted for their porosities and permeabilities to accept large volumes of fluid.

least 100 earthquakes of this same size have occurred annually since 2013. The annual number of earthquakes (with a magnitude of 3.0 or larger) peaked in 2015 when 1,010 magnitude 3+ earthquakes were recorded. Given their magnitude, most of these earthquakes are large enough to have been felt by people, yet small enough to cause significant damage (USGS, 2022).

Exhibit 5-1. Earthquakes in the Central and Eastern U.S. 1973–2022



The following are examples of induced seismic events in the United States that have occurred in basins where unconventional natural gas production via hydraulic fracturing has occurred.

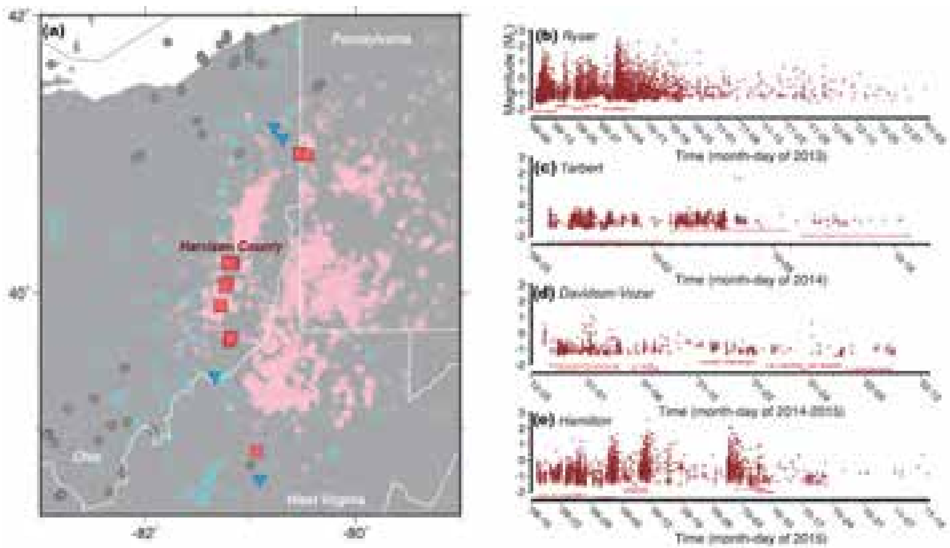
5.1.1 Utica and Marcellus Shales in the Appalachian Basin

The Appalachian Basin is currently the largest natural gas producing area in the United States. The basin produced over 18 Mcf of natural gas a day (500 m^3/day) in 2019 (EIA, 2019a). The Marcellus and Point Pleasant Utica shale plays are both located in the Appalachian Basin and extend from New York to Kentucky. They each cover prospective areas of 190,000 and 220,000 square kilometers (km^2), with proven reserves of 135 and 24 Tcf of natural gas, and 345 and 210 MM barrels of oil, respectively (EIA, 2019b). Earthquakes detected in the basin during 2013–2015 are presented in Exhibit 5-2.

The map on the left provides the location sequences of cataloged (magnitude > 2.0) seismic events in Ohio and neighboring states for 2010–2017. Blue triangles show earthquake sequences induced by wastewater disposal; red squares show earthquake sequences induced by hydraulic fracturing; and pink squares and blue triangles depict the horizontal and wastewater disposal wells that remain in the area. Grey circles represent earthquakes assumed to be occurring from natural causes. The four graphs on the right provide the temporal

distribution of hydraulic fracturing induced seismic events for four wells in Harrison County, Ohio (Schultz, 2020).

Exhibit 5-2. Location and timing of induced and natural seismic events in the Appalachian Basin



Permission pending from Schultz (2020)

5.1.2 Anadarko and Arkoma Basins of Oklahoma

Dramatic increases in seismic activity have been reported for areas in both central and northern Oklahoma where the Anadarko and Arkoma Basins are located. Historically, an average of one to two ML[k] ≥ 3.0 earthquakes have occurred in Oklahoma annually. The number of ML ≥ 3.0 earthquakes occurring in the state, however, rose to over 900 in 2015.

While the seismicity rate began to decline in 2016 the yearly total seismic moment of Oklahoma remained high in response to three Mw[l] ≥ 5.0 earthquakes occurring during the year. Including the Pawnee earthquake, the largest earthquake (5.8 Mw) ever recorded for the state of Oklahoma. The seismicity rate increase has generally been attributed to the disposal of large volumes of produced water into the Arbuckle Group basin (Haffener, Chen, and Murray, 2018).

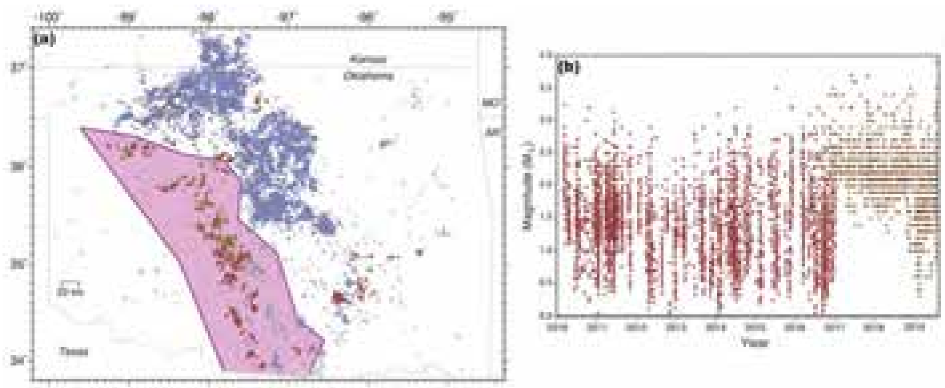
Exhibit 5-3 shows the location (left) and magnitude (right) of induced seismic events in Oklahoma between 2010 and 2020. In the map on the left seismic events from natural causes are represented by the blue circles, while induced seismic events are represented by the red (Skoumal et al., 2018) and orange circles (Shemeta, Brooks, and Lord, 2019). The graph on the

[k] ML refers to the magnitude on the Richter scale, where M stands for magnitude and L stands for local.

[l] Mw is known as the moment magnitude of an earthquake. For very large earthquakes, moment magnitude gives the most reliable estimate of earthquake size.

left shows the number and magnitude of the induced seismic events over time (Skoumal et al., 2018; Shemeta, Brooks, and Lord, 2019).

Exhibit 5-3. Induced seismicity events in Oklahoma



Permission pending from Schultz (2020)

5.1.3 Fayetteville Formation in the Arkoma Basin of Arkansas

Following the success of the Barnett Shale (Fort Worth Basin, Texas) the Fayetteville Formation in Arkansas became an early target for continued shale gas development in the United States. This unconventional play runs east to west across north central Arkansas, extending across nearly 150 km. By 2005, horizontal well completions in the middle to lower organic rich facies at depths typically 1–2 km were coming online and, by 2009, 0.5 Tcf of gas was being produced per year (Browning et al., 2014).

The Fayetteville Formation has a history of seismicity that dates back to before the region was developed for oil and natural gas extraction. In September 2010, a series of seismic events reaching magnitudes close to 5.0 Mw on the Richter Scale occurred along the Guy-Greenbrier Fault within the basin. Not long after on February 28, 2011, a 4.7 Mw earthquake—the largest ever recorded—occurred within the basin. This led to concerns that even larger earthquakes could potentially occur in the area, which resulted in an emergency shutdown order for any injections being put in place by the Arkansas Oil and Gas Commission. Analysis of the seismicity, injection patterns, and pore pressure diffusion built a strong case for the activation of the Guy-Greenbrier Fault by wastewater disposal (Horton, 2012; Ogwari, Horton, and Ausbrook, 2016; Ogwari and Horton, 2016; Park et al., 2020). In the neighboring states of Oklahoma and Texas, wastewater disposal by injection is understood to be the primary driver of induced seismicity.

5.1.4 Eagle Ford Shale Play in the Western Gulf Basin of Texas

Texas has a long history of active oil and natural gas production, hydraulic fracturing, wastewater disposal, and general seismicity. Some of which occurs within or near areas of

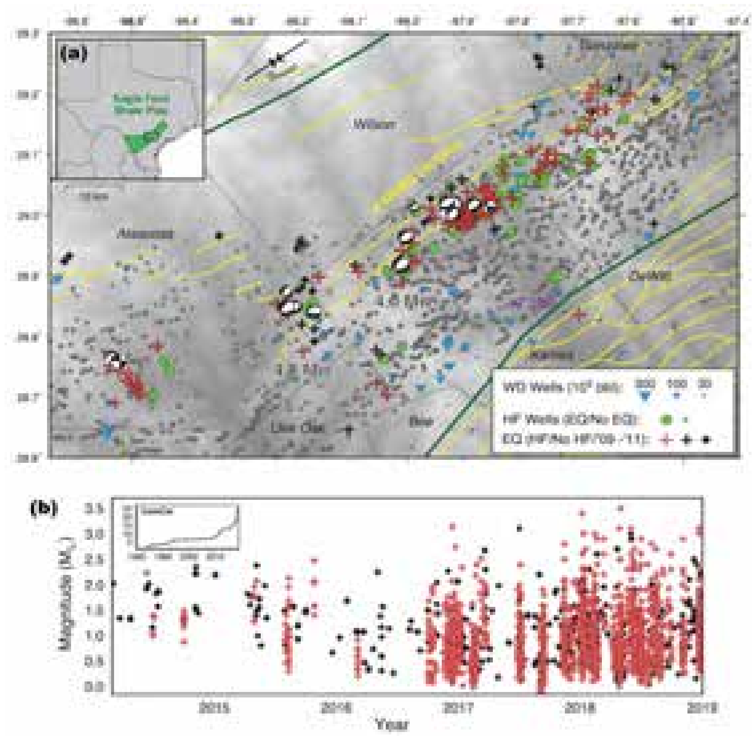
pervasive faulting (see Exhibit 5-4a) (Ewing, 1990; Frohlich et al., 2016). Advancements in horizontal drilling and hydraulic fracturing since 2008 have prompted the Eagle Ford shale play to focus on hydrocarbon production from the Upper Cretaceous Eagle Ford and Austin Chalk Formations (Frohlich and Brunt, 2013; Martin et al., 2011; Pearson, 2012; RRC, 2019).

In 2018, the rate at which ML ≥ 3.0 earthquakes occurred in the Eagle Ford shale play was 33 times higher than background levels (3 earthquakes per 10 years during 1980–2010; see Exhibit 5-4b). Fasola et al. (2019) investigated seismicity that has occurred since 2014, in an effort to identify how hydraulic fracturing has contributed to seismicity within the play. Comparing both times and locations of hydraulic fracturing to a catalog of seismic activity, Fasola et al. (2019) suggest more than 85 percent of the seismicity that occurred was spatiotemporally correlated with hydraulic fracturing. More specifically, there were 94 ML ≥ 2.0 earthquakes correlated will 211 hydraulic fracturing well laterals.

Exhibit 5-4a provides a map from the Texas Seismological Network showcasing earthquakes (crosses) and focal mechanisms (beach balls) that have occurred since 2017. Hydraulic fracturing wells are indicated by black circles in Exhibit 5-4. Correlated earthquakes and hydraulic fracturing wells are displayed as red plus signs and green circles, respectively. Black diamonds show the earthquakes that occurred during 2009–2011 (Frohlich and Brunt, 2013). Purple square shows the seismic station (735B) used for template matching. Wastewater disposal wells are provided as teal triangles sized by median monthly volumes. Arrows show regional orientation (Lund Snee and Zoback, 2016). Faults (Ewing, 1990) are in yellow.

Exhibit 5-4b provides the magnitudes of the various earthquakes both correlated and not correlated with hydraulic fracturing that occurred annually after 2011 within the play (the black and red plus signs shown in Exhibit 5-4a). The inset shows the cumulative number of earthquakes (magnitude ≥ 3.0) occurring in the area, available from the United States Geological Survey (USGS) Comprehensive Catalog.

Exhibit 5-4. Locations and timings of Eagle Ford hydraulic fracturing induced event



Permission pending from Fasola et al. (2019)

5.2 Regulations to Address Induced Seismicity and On-Going Research and Development

State regulators have long been focused on identifying the precise location and magnitude of earthquakes and determining their cause. If earthquakes can be linked to wastewater injection, regulators could instruct operators to cease or limit either injection rates and/or water volumes in nearby wells (EPA UIC National Technical Workgroup, 2015). Many regulators also require that new injection wells avoid areas near known active faults. In Oklahoma, these techniques have effectively reduced the number of felt earthquakes.

Similar procedures have been applied to hydraulic fracturing operations in some states. That is when earthquakes are detected, operations are either modified or suspended (AGI, 2017). Oklahoma, Texas, and Ohio have all taken steps to mitigate induced seismicity linked to hydraulic fracturing. In Oklahoma, regulators have instituted the following actions to address induced seismicity (Boak, 2017).

- Governor creates Coordinating Council on Seismicity (2014)

- Oklahoma Corporation Commission directives reduce injection (2015)
- Oklahoma Geological Survey position paper (2015)
- Secretary of Energy funds $200,000 seismicity projects (2015)
- Governor's Water for 2060 Produced Water Working Group (2015)
- Research Partnership to Secure Energy for America funded stations added to Oklahoma Geological Survey network (2016)
- Governor's Emergency Fund $1,387,000 to Oklahoma Corporation Commission, Oklahoma Geological Survey (2016)
- New tracking system for earthquakes and injection for Oklahoma Corporation Commission (2016)

Texas' Center for Integrated Seismicity Research (TexNet) is charged with monitoring, locating, and cataloging seismicity across the state. Capable of detecting and locating earthquakes with magnitudes ≥ 2.0 TexNet's backbone network improves investigations of ongoing sequences of seismic activity by deploying temporary seismic monitoring stations and conducting site-specific assessments (Young et al., 2017). TexNet will continue conduct fundamental and applied research to better understand both naturally and potentially induced seismic events that are occurring across the state of Texas, their associated risks, and strategies for communicating with stakeholders and responding to public concerns regarding seismicity. (Young et al., 2017)

Components include the following (Young et al., 2017):

- Applicants are required to search USGS seismic database for historical earthquakes within a circular area of 100 square miles around a proposed, new disposal well (~5.6-mile radius)
- Clarifying RRC's authority to modify, suspend or terminate a disposal well permit, or modify operations, if scientific data indicates a disposal well could be contributing to seismic activity
- Increased disclosure of reported volumes and pressures, at RRC's discretion
- RRC may require applicant to provide additional technical information to demonstrate disposal fluid confinement

Ohio has regulated seismic permits for injection wells for some time; obtaining a permit can require the following tests or evaluations of a proposed brine injection well be completed, in any combination that the chief deems necessary (Dade, 2017):

- Geological investigation of potential faulting within the immediate vicinity of the proposed injection well location, which may include seismic surveys or other methods determined by the chief to assist analysis.
- Permit conditions may include seismic monitoring, pressure fall-off tests, spinner tests, radioactive tracer, geophysical and electrical logs, and downhole pressure monitoring.

Restrictions may be placed on wells drilled near faults or areas of known for seismic activity, in which seismic monitors must be installed for a specified period prior to completion operations (Dade, 2017):

- ML ≥ 1.5 – Direct communication starts between operator and division
- ML = 2.0–2.4 – Work with operator to proposed or modify operation
- ML ≥ 2.5 – Temporary halt completions on lateral
- ML = 3.0+ – Completion on pad suspended until an approved plan is submitted by operator

The mitigation techniques employed by Ohio include the following:

- Direct communication with the operator is essential
- Discussion of seismic events and stages of the operation in real-time
- Spatial analysis and time correlation with completion data during the operation

Mitigation techniques when induced seismicity occurs during hydraulic fracturing include the following:

- Change from zipper fracking to stack fracking
- At least 20% reduction in volume and/or pressure
- Skipping stages may be necessary, especially if seismic events indicate a lineament or fault structure near a lateral of the operation
- Switch to smaller sieve sizes for proppant, full effect still unsure

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6 Land Use and Development

The growing land use footprint of energy development, termed "energy sprawl," will likely cause significant habitat loss and fragmentation with associated impacts to biodiversity and ecosystem services (McDonald et al., 2009). Land presents a critical yet often overlooked constraint to energy development including the development of domestic natural gas. Natural gas is set to act as a transition fuel and dominant technology during the grid decarbonization process in the United States, making an understanding of its land use implications critical and necessary consideration (Dai et al. 2023).

Expanding energy development is now the primary source of anthropogenic land cover change in natural ecosystems in North America (Allred et al., 2015; Trainor, McDonald, and Fargione, 2016), including eastern deciduous forests, boreal forests, prairie grasslands, sagebrush-steppe, and deserts (Copeland, Pocewicz, Kiesecker, 2011; McClung and Moran, 2018; Appiah, Opio, Donnelly, 2019). Land use and development issues associated with natural gas production include local surface disturbance; cumulative landscape impacts; habitat fragmentation; and traffic, noise, and light. Vertical wells are typically spaced with 40 acres per well, the drill pads from which each horizontal well originates are typically spaced with 160 acres per well. If wells are drilled conventionally (i.e., vertically) a single square mile of surface area can support 16 pads with one well per pad. If wells are drilled horizontally then the same amount of surface area could support be used to develop 1 pad, from which 6–8 different wells could be drilled (NETL, 2009).

Commented [HSAJ23]: Comment for FE/HQ: In some cases the best source of information we had for land use impacts predated 2014. Please advise if you would like to see these removed.

The Citizens Marcellus Shale Coalition (CMSC) (2011) explored two issues related to impacts of shale gas production on public lands and the other industries that rely on these lands. They also explored the impacts on private property rights. CMSC stated that shale gas development must consider the cumulative impacts on state parks and forests and on timber and tourism industries as part of responsible stewardship of public resources. Property rights and environmental degradation are a growing public concern, and eminent domain laws, drill spacing requirements, and grouping of leased lands could help protect these rights.

6.1 Surface Disturbance and Landscape Impacts

The infrastructure to needed to support the supply chain of electricity produced from natural gas involves production sites (production pads and their access roads), transportation facilities (e.g., gathering and transmission pipelines for natural gas), processing facilities, and power plants (end-use) (Dai et al., 2023). Such activities can disturb Earth's surface, the impacts of which can extend over large areas and result in habitat fragmentation that impacts both plant and animal species. Mitigation options include adoption of best-practices for site development and restoration, avoidance of sensitive areas, and minimization of impacts to disturbed areas.

Dai et al. (2023) used machine learning, remote sensing, and geographic information systems to obtain spatially explicit information on the land required to support natural gas production. Their analysis considered land use across five life cycle stages of natural gas produced for electricity production from wells (production stage), natural gas transportation via gathering pipelines (gathering stage), natural gas processing plants (processing stage), natural gas transportation via transmission pipelines (transmission stage), and the use through combustion in gas-fired power plants (use stage).

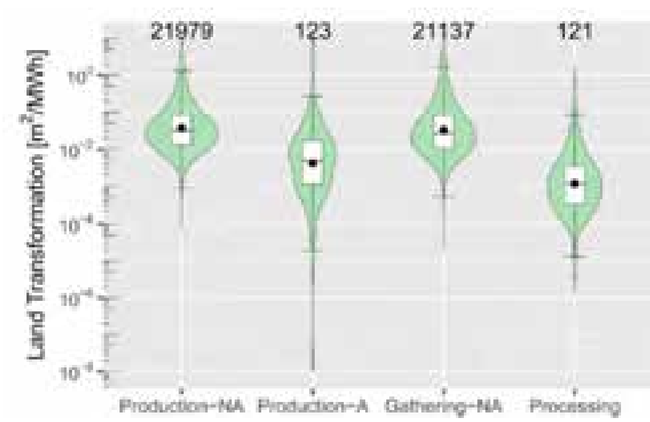
For the production stage, Dai et al. (2023) map land-use for 100,009 wells located at 75,915 different well pads. Among the 100,009 wells examined, 31,716 were co-located. In non-agricultural areas, results suggest vertical wells occupy ~4000 square meters (m^2) less land per site than horizontal-/directional-drilled wells. During the gathering stage in both agricultural and non-agricultural areas, sites with horizontal-/directional-drilled wells, on average require ~230 meters less pipeline in length than sites with vertical-drilled wells, whereas due to the requirement for larger width of right-of-way, the extent of land use is almost doubled for sites with horizontal-/directional-drilled wells. Results from Dai et al. (2023) are summarized in Exhibit 6-1.

Exhibit 6-1. Land use throughout the life cycle of gas-fired electricity

Stage			Unit	Average
Production	Agricultural	Directional	m^2 per site	9,346
		Vertical	m^2 per site	2,100
	Non-agricultural	Directional	m^2 per site	18,170
		Vertical	m^2 per site	14,090
Transportation by gathering	Length	Directional	m^2 per site	597
		Vertical	m^2 per site	818
	Area	Directional	m^2 per site	20,157
		Vertical	m^2 per site	10,128
Processing			m^2 per (MM cubic feet per day)	4,318

Exhibit 6-2 from this study illustrates the land transformation by stage, showing that production in non-agricultural areas utilizes more land than agricultural areas.

Exhibit 6-2. Land transformation in natural gas production



Note: NA = non-agricultural area, A = agricultural area

Used with permission from Dai et al. (2023)

Notably, technological advancements will play a significant role in decreasing the amount of land that will be transformed during the life cycle stages of production, gathering, and use of natural gas (Dai et al., 2023).

6.2 HABITAT FRAGMENTATION

The construction and installation of the infrastructure necessary for development of natural gas can lead to a habitat being converted from a large contiguous patch of similar environments to several smaller, isolated environments. Long-term effects of shale gas production on habitat disturbance will have to be evaluated as the development of these resources continues. Mitigation measures such as avoidance, best management practices, and prompt reclamation of the drilling site have been put forward as ways to best minimize the possible impacts that shale gas production may have on habitats. Habitat disruption can also result from a lack of surface water availability in response to withdrawals to support natural gas production and quality from erosion and chemical spills. The potential water use implications of natural gas are discussed in Chapter 4 – Water Use and Quality.

There are several impacts associated with the development of gas drilling sites and natural gas production that can disrupt the habitat of both plant and animal species. These impacts can arise from a variety of sources and at various points throughout the extraction and production process. Habitat fragmentation occurs when infrastructure must be installed, or land clearing must take place to allow access to a well location. Habitat fragmentation was given as one of the environmental risk pathways that were identified as a consensus priority risk pathway in a survey of 215 experts in government, industry, academia, and non-governmental organizations (RFF, 2013).

When contiguous core habitats are fragmented into smaller patches, many sensitive species are unable or unwilling to cross non-habitat regions to reach alternative habitat patches. While habitat loss can have an immediate impact on wildlife population, the ecological response to fragmentation is lagged, and affects different species at varying timescales (Makki et al., 2013).

A secondary impact of fragmentation is the creation of edges. Edges are generally defined as the 100 meters between core forest and non-forest habitat (PADEP, 2014; Kargbo, Wilhelm, and Campbell, 2010; Johnson et al., 2010). New edges affect the physical or biological conditions at the ecosystem boundary and within adjacent ecosystems (Fischer and Lindenmayer, 2007). Edge effects are believed to be detrimental by increasing predation, changing lighting and humidity, and increasing the presence of invasive species (Johnson et al., 2010).

Exhibit 6-3 provides a schematic depicting the habitat loss and fragmentation from natural gas production. Exhibit 6-3 progresses from infrastructure development that has quantifiable land impacts leading to temporally extended land changes, which account for habitat loss and fragmentation.

Exhibit 6-3. General procedure for depicting land disturbance from natural gas extraction

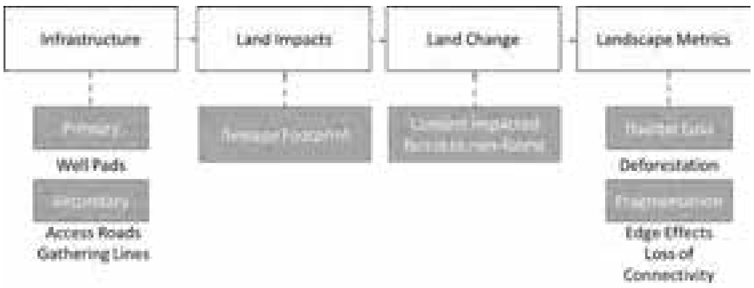
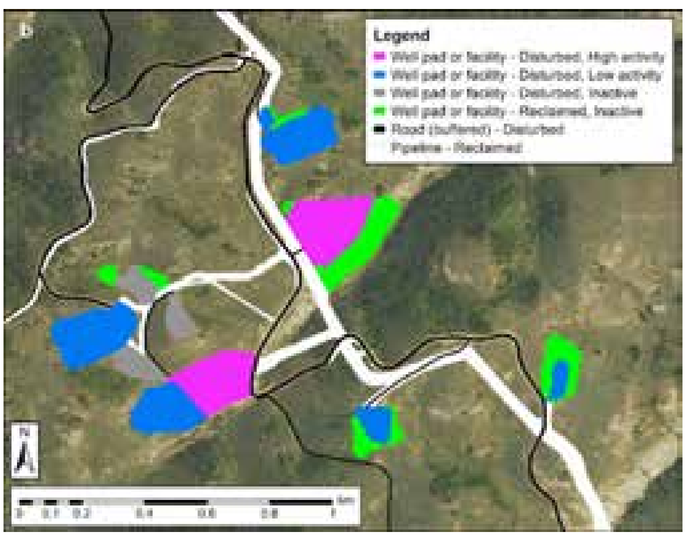


Exhibit 6-4 provides an example of energy infrastructure features digitized from 2013 National Agricultural Inventory Program satellite imagery overlaid with well locations reported in COGCC data. Each mapped feature (or portion thereof) was classified by type (well pad, facility, road, or pipeline) and by surface type (disturbed or reclaimed), and well pads and facilities (or portions thereof) were assigned an activity status (high, low, or inactive) (Walker et al., 2020).

Exhibit 6-4. Footprint of a well pad and surrounding infrastructure



Used with permission from Walker et al. (2020)

Each region where natural gas extraction takes place has unique species that inhabit the particular regions. Within those species, some are more greatly affected than others, whether it be core habitat fragmentation of edging.

6.3 NOISE, LIGHT, AND TRAFFIC

Natural gas development processes are associated with both noise and light pollution, which can contribute to stress among those living in nearby communities (Down, Armes, Jackson, 2013; Korfmacher et al., 2013; Peduzzi et al., 2013; Witter et al., 2008a; Witter et al., 2008b). Construction, vehicles, drilling, compressors, flaring, and other processing equipment and facilities can all pollute through excessive noise and continuous illumination (Cleary, 2012).

6.3.1 Noise Pollution

The health impact assessment in Colorado identified noise pollution as an area of concern and noted that it occurs during drilling and completion operations, flaring, and as a result of traffic (Witter et al., 2013). Workers can be exposed to noise through many sources on site, including diesel engines, drilling, generators, mechanical brakes, operation of heavy equipment, and radiator fans (Witter et al., 2014); therefore, hearing impairment is a noise-related health concern for workers on site.

A biomonitoring study from Texas found residents reporting concerns about odors and noise apparently related to shale gas well and compressor station operations, although this was a separate, independent component from the biomonitoring portion in order to address residents' concerns (Texas Department of State Health Services, 2010). While the authors noted that it was difficult to determine if the levels were above acceptable limits that may be harmful to human health and that noise may affect quality of life, this is speculative because noise levels were not measured to establish decibels of noise in the study area.

Noise standards for a single well pad may be met; however, the cumulative effects of multiple operations in one area might exceed these established decibel levels. In terms of setback distances, some noise regulations distinguish between maximum decibels for day and night, while others distinguish between maximum decibels for certain phases of the operation such as drilling, fracturing, and production; however, there is often variability and, in some areas, it is suggested that distances are set as monitoring points, not necessarily points indicative of being protective of health (Fry, 2013).

6.3.2 Light Pollution

Light pollution has significant implications for the environment and public health, and its effects have become more pronounced over time due to the increasing extent and radiance of artificially-lit areas (Kyba, 2017). Substantial economic values have been attached to affected outcomes, such as biodiversity, recreation, and public health. With respect to human health, artificial lights at night are associated with sleep deprivation and mental health (Patel, 2019; Xiao, 2020); sleep deprivation, in turn, has been shown to reduce cognition and labor market productivity, as well as elevate mortality risks associated with dementia, heart attacks, and vehicle accidents (Hafner et al., 2017; Paksarian et al., 2020; Ma et al., 2020; Jin and Ziebarth, 2020; Prats-Uribe, Tobías, and Prieto-Alhambra, 2018.). A study in Australia quantified the financial and non-financial costs of inadequate sleep in 2016–2017 to be $45 B (Hillman et al., 2018) and another study estimates that $680 B is lost due to sleep deprivation across five

Organisation for Economic Co-operation and Development countries (Hafner et al., 2017; Boslett, 2021).

Light pollution also has significant consequences for wildlife populations. It affects nighttime behavior and habits of terrestrial (Bennie et al., 2015) and marine (Davies et al., 2014) wildlife populations, particularly for species that use sun or moon light for guidance. It disrupts natural sleep and reproductive cycles, geographical orientation, and predator-prey relationships (Longcore and Rich, 2004). Other effects of light pollution include changes in bird singing behavior (Miller, 2006), estrus patterns in nocturnal primates (LeTallec, Théry, and Perret, 2015), insect pollination (MacGregor, 2015), and fish biological rhythms (Brüning et al., 2015). These impacts have led to ecosystem-wide changes in biodiversity and growing disparities between entire taxonomic groups (Davies et al., 2013).

The impacts of light pollution also extend to human health and well-being. Artificial light disrupts melatonin secretion and circadian rhythm (Haim and Zubidat, 2015) with corresponding changes on mood regulation, depression, and sleeping disorders (Cho et al., 2016). Light pollution-driven changes in circadian rhythms may also have contributed to recent growth in obesity and metabolic dysfunction (Fonken et al., 2010). Growing laboratory and epidemiological evidence also support the long-hypothesized relationship between nighttime light exposure and cancer rates (Kerenyi, Pandula, and Feuer, 1990; Kloog, et al., 2010; Schwimmer et al. 2014; Jones, Pejchar, and Kiesecker, 2015).

While there is some work speculating that light pollution associated with shale development induces psychosocial stress (Fisher et al., 2017), sleep and mental health issues (Casey et al., 2018), and local ecosystems (Kiviat, 2013), the literature directly connecting the recent resource boom to light pollution is extremely limited. Importantly, no work has documented the causal impact of U.S. shale development on light pollution.

6.3.3 Traffic Pollution

Traffic may increase in any given area as a result of unconventional natural gas development, but the magnitude of this increase has not been studied in depth. The phases of development that require the most traffic load involve well pad construction, drilling and well completion, and pipeline construction (Witter et al., 2014). It appears that changes in traffic patterns will be dependent upon the area and the individual project or cumulative effects of multiple projects in an area. Industrial truck traffic can be detrimental to health-related air quality due to vehicle exhaust, as well as pose an increased risk of motor vehicle crashes.

In the *Revised Draft Supplemental Generic Environmental Impact Statement on The Oil, Gas and Solution Mining Regulatory Program*, the New York State Department of Environmental Conservation (NYSDEC) identified temporary but adverse noise and visual impacts from construction activity and increased truck traffic among the potential land-use environmental impacts associated with natural gas production (Witter et al., 2014). Significant adverse impacts in terms of damage to local and state roads could also result. Among mitigation measures described for environmental impacts, NYSDEC suggests imposing measures to reduce the adverse noise and visual impacts from well construction. A transportation plan could also be required that would include proposed truck routes and assess road conditions along the proposed routes. Exhibit 6-5 tabulates the number of truck trips for a typical shale gas well (Massachusetts Institute of Technology [MIT], 2011).

Exhibit 6-5. Truck trips for a typical shale gas well drilling and completion

Activity	1 Rig, 1 Well	2 Rigs, 8 Wells
Pad and Road Construction	10–45	10–45
Drilling Rig	300	60
Drilling Fluid and Materials	25–50	200–400
Drilling Equipment (casing, drill pipe, etc.)	25–50	200–400
Completion Rig	15	30
Completion Fluid and Materials	10–20	80–160
Completion Equipment (pipe, wellhead, etc.)	5	10
Fracturing Equipment (pump trucks, tanks, etc.)	150–200	300–400
Fracture Water	400–600	3,200–4,800
Fracture Sand	20–25	160–200
Flowback Water Disposal	200–300	1,600–2,400
TOTAL	1,160–1,610	5,850–8,905

The large volumes of water involved in fracturing operations can create high volumes of road traffic given the majority of the water used for fracturing is transported by truck. It should be emphasized that the large number of traffic movements shown in the table above are worst-case estimates. In particular, re-use of flowback wastewater significantly reduces the amount of road traffic associated with hauling water, which represents much of the traffic movement. Furthermore, large-scale operators are also using pipelines to transport water to the site, substantially reducing the amount of road traffic (MIT, 2011).

The Eagle Ford Shale Task Force Report for the RRC identified increased traffic and deterioration of roads and bridges among the infrastructure impacts from shale gas development (Porter, 2013). Exhibit 6-6 lists estimates of the number of truck-trips-per-shale-gas-well in the Eagle Ford (Porter, 2013).

Exhibit 6-6. Loaded truck trips per gas well

Activity	Number of Loaded Trucks
Bring well into production	1,184
Maintain production (per year)	Up to 353
Re-fracturing (every 5 years)	997

These impacts are enough of a concern that the task force considered alternative financing methods to help meet the increased demands on roads and bridges (Porter, 2013).

Upadhyay and Bu (2010) surveyed the visual impacts of Marcellus drilling and production sites in PA. They reviewed the drilling process, assessed direct visual impacts, and compared the results to the impacts of other technologies (e.g., windmills and cell towers). They also studied drill-pad density from map and aerial perspectives to examine the likelihood of seeing drill towers across a landscape, and the modeled potential impacts for increased drilling, making the following conclusions:

- Serious impacts from light and noise are a potential problem within a small radius of drilling sites.
- Indirect impacts like increased truck traffic, equipment storage, and temporary structures compose the most salient visual impacts, rather than the drill pads themselves.
- Timelines for site restoration of visual impacts vary significantly.

Upadhyay and Bu (2010) recommended that visual impacts be addressed during the siting and design phase and that nighttime impacts could be avoided by pointing lights downward.

The RFF (2013) report also gave several options in their survey of experts under the category of community disruption. Included in this category, as well as habitat fragmentation, were such risks as light pollution, noise pollution, odor, and road congestion. The industry respondents identified a number of these community disruptions as risk pathways of high priorities, while the other respondent groups identified more conventional (air pollution, water pollution, etc.) risks.

6.4 Regulations and Strategies to Reduce Land Impacts

While there are very few regulations to reduce the impacts on land, habitat, noise, light, and traffic pollution, best practices have been developed in some cases.

6.4.1 Mitigation Options for Habitat Fragmentation Impacts

The NYSDEC (2011) study proposed that, if the development area included a region of continuous forest over 150 acres in size or a region of grassland over 30 acres, an ecological assessment should be conducted to identify best management practices.

A 2012 study of hydraulic fracturing practices in the Inglewood oil field in California, operated by the Plains Exploration & Production Company proposed that the best way to mitigate habitat fragmentation impacts is to adopt best management practices, perform wildlife surveys, and implement restrictions during migration and mating seasons (Cardno ENTRIX, 2012). The study also found that ensuring that well pad reclamation occurs is the most productive method to reduce harm to populations (Cardno ENTRIX, 2012).

Avoiding disturbances to sensitive areas such as wetlands, waterways, and wildlife habitats when locating drilling sites could be the best method for mitigating impacts. Reclaiming the land upon completion of drilling activities is the best way to mitigate impacts in those cases when avoiding disturbances is impossible (NETL, 2009). Proceeding with reclamation processes as quickly as possible can minimize the disturbances, but all mitigation measures (including

avoiding disturbances to begin with) are subject to the landscape, plants, and wildlife that are present at a site.

The Western Governors' Association (2006) released a handbook outlining the best management practices for CBM development to be shared among the Association's shareholders. The practices are split into multiple categories, including planning, water, landowner relations, and infrastructure. Several subcategories can be applied to mitigating habitat fragmentation, such as protection of wetland areas, roads and transportation, pipelines and power lines, habitat and species protection, and wells. To protect wetland and riparian areas, facilities such as well pads should be sited outside of such regions as much as possible, and features that cut across the landscape, such as roads and pipelines, should avoid crossing wetlands and riparian areas as much as possible (Western Governors' Association, 2006). Best practices for mitigating disturbance from roads and transportation include keeping road development to a minimum, using existing access roads as much as possible, using unimproved roads as little as possible during wet weather, following road construction and maintenance standards, avoiding sensitive areas, and attending to safety issues and other problems (Western Governors' Association, 2006). Recommendations of best practices for pipelines and other lines include using existing pathways, installing as many lines as possible in a single location, and using the least invasive construction equipment possible. To protect habitat and sensitive species, lines should be buried rather than installed above ground if possible. Well sites should minimize the amount of surface disturbance that occurs and should be reclaimed as quickly as possible upon completion of development activities (Western Governors' Association, 2006). Again, these best management practices have been developed in areas of CBM production by the Western Governors' Association, but many of these practices are applicable to shale gas development.

Drilling on federal or public lands is subject to oversight by federal agencies, and sections of the Endangered Species Act may require that species of plants or animals not be threatened by the permitted drill site (NETL, 2009). Mandatory plans for mitigation and reclamation may be required to ensure that impacts on wildlife and habitat will be as minimal as possible (NETL, 2009).

With approximately 33 units of the National Park System in or near the Marcellus Shale, NPS found it important to be informed and current with development issues. Moss (2012) provides an overview of the geology, technology, current activity, and potential environmental impacts. Among the effects described are widespread development and well spacing, site space needs, water use, aquifer contamination, air quality, and truck transportation. There are then four recommendations to help park units prepare for potential shale gas development on and around NPS lands (Moss, 2012):

1. Check land and mineral ownership – Know if private in-holdings or private or state mineral estate underlie an NPS unit.
2. Be aware of industry interest adjacent to park boundaries – Land speculation, exploration, or drilling could signal increased requests for drilling permits. Contact the state oil and gas agency to express concerns and issues.

3. Work with state agencies – Meet with the state permitting agency, establish agreements, engage before issuance of permits, and if possible, have protective mitigation measures included directly in the lease.

The NPS Geologic Resources Division assists parks with policy and technical issues and reviews permitting and environmental documents to help mitigate or eliminate adverse impacts (Moss, 2012).

In January 2013, the BLM updated a presentation detailing best management practices for wildlife management that can help to minimize habitat fragmentation. The document offers several practices that can be implemented or planned to lessen impacts on habitat. The well pad itself and the immediate surroundings can be fit to the space available to minimize the disturbed area, rather than constructing a generic rectangular pad (BLM, 2013). There are also multiple examples of reclamation practices, both at the drill site and on access roads, that can be implemented to lessen the impact of the infrastructure. The well pad and supporting infrastructure (roads, pads, storage, and pipes) can be designed to be as efficient and minimally obstructive as possible (BLM, 2013). Wells can be remotely monitored using telemetry, pipelines and other lines can be buried where possible, and any existing corridors for roads and lines should be used whenever possible (BLM, 2013). It is helpful to monitor local wildlife populations to ensure that mitigation and reclamation measures are effective, and final reclamation upon abandonment of the well is critical to the long-term effectiveness of mitigation options (BLM, 2013).

6.4.2 Reducing Light Pollution

Even two decades after the establishment of designated programs by non-government organizations to recognize and certify the quality of night skies and nighttime darkness resources, the very notion of what a "dark sky" is remains unsettled from a scientific standpoint (Crumey, 2014); while appropriate instrumentation can quantify night sky brightness, it cannot properly account for the human aesthetic experience of natural night. However, various lines of research increasingly suggest that unsafe thresholds of exposure to artificial light at night in terms of intensity, duration, wavelength, and timing likely exist for humans, plants, and animals. In this sense, light-sensing technologies applied in the field could effectively serve as "dosimeters" for monitoring these exposure parameters (Barentine, 2019).

6.5 DOE Research and Development and Analysis

An independent review of the literature suggests there is currently no research and development or analysis with respect to land use, habitat fragmentation, or light, noise, or traffic pollution being conducted by DOE.

Commented [HSAJ24]: Comment for FE/HQ- Please advise if this is incorrect. We made every attempt to find information on current and ongoing R&D.

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7 Social Justice and Natural Gas/Liquefied Natural Gas Market Development

7.1 Introduction

Granting authorizations to import and/or export natural gas into and from the United States could potentially generate and, in some cases, further perpetuate instances of energy, environmental, and social injustice. Conversely, if potential impacts to disadvantaged and frontline communities[m] are both carefully considered and minimized, then opportunities to advance environmental, energy, and social justice may also be present. Ensuring the advancement of energy, environmental, and social justice across the domestic natural gas market, however, requires meaningfully engaging historically disadvantaged and frontline communities and ensures exposure to harms or burdens for these communities are prevented and minimized.

These types of considerations have driven the implementation of the Biden-Harris Administration's Justice40 initiative that was mandated under Executive Order 14008, and which has an explicit goal that 40 percent of the overall benefits from federal investments should flow to historically disadvantaged and disenfranchised communities and communities burdened by pollution. Specific types of projects include those related to the clean energy transition both in energy production and the advancement for net-zero emission transportation. Additional categories include affordable housing and "green" workforce development and training, as well as those focused on the remediation of legacy pollution, clean water initiatives, and wastewater projects. Introducing the Justice40 (2023) framework to the ways in which government measures the distribution of investment benefits attempts to right the historical wrongs that have resulted in the unequal outcomes seen today by requiring the success of projects to be measured according to whom the benefits and burdens are distributed.

This chapter seeks to summarize the incorporation of social, environmental, and energy justice concepts found in the broader research literature as they relate to natural gas and LNG market development. The goal is to summarize what already exists and provide guidance as to how future research might be pursued at the nexus of social, energy, and environmental justice and project development. This literature review specifically focuses on the development of large-scale energy infrastructure intended to supplement the energy-transition goals outlined by the current administration and its policies. However, the challenge (and opportunity) researchers face in this space is rooted in the relatively less robust focus that has been spent on applying energy, environmental, and social justice concepts to the development of energy infrastructure projects specifically for natural gas and LNG markets.

[m] Per the National Oceanic and Atmospheric Administration (NOAA), frontline communities are "those who are the most vulnerable to and will be the most adversely affected by climate change and inequitable actions because of systemic and historical socioeconomic disparities, environmental injustice or other forms of injustice" (NOAA, 2023).

Due to the nascency of research that links social, environmental, and energy justice issues with the development of natural gas and LNG markets, this literature review will cover research that has already connected these issues and weave together the separate literature areas into the discussion. For reference, this review uses the structure presented in Spurlock et al. (2022) that outlines a tractable framework to incorporate energy justice tenets into energy infrastructure planning decisions and deep decarbonization policy implementation strategies.

Commented [RK25]: While the application of a justice framework to this energy context is conceptual - there is a robust literature on socioeconomic and community impacts of UOG development in the last ten years. Will share a separate doc with recommendations.

Commented [RK26R25]: If these recommendations are included then a title "Societal Considerations, Impacts, and Justice in UNG and LNG infrastructure development"

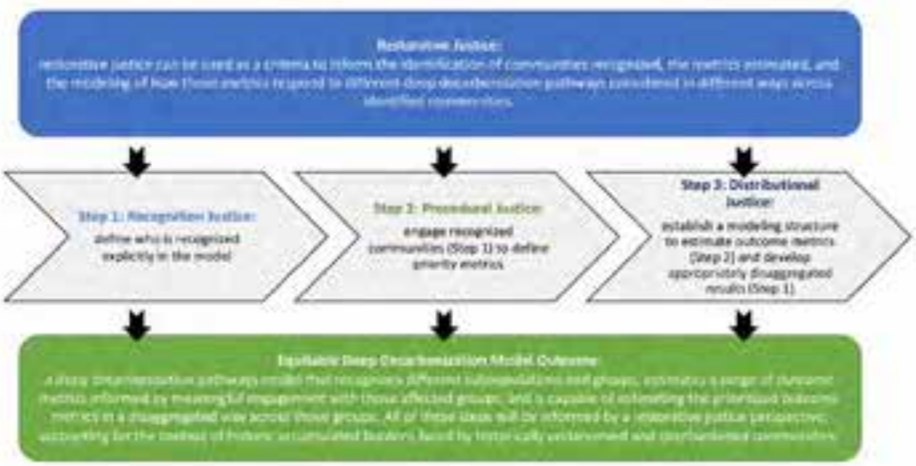
Commented [BO27R25]: I think these recommendations on the impact of development efforts may be better suited to the follow-on effort to this chapter referenced by Tom Curry in Friday's call. They synch up with some of his descriptions of Natenna's recommendation that were more about the next logical extension of a chapter like this.

This discussion is further framed as a struggle to balance energy justice issues rooted in the unequal exposure to pollution and burdens with the need to resolve where communities do not have equitable access to clean, affordable, and reliable energy. This chapter concludes by underscoring the idea that incorporating energy justice tenets (distributional, procedural, and recognition) must be done from the big-picture view of energy project governance as it is the point where all project planning, development, and implementation is most directly influenced. It is from the point of governance that the effort to ameliorate energy poverty through the implementation of environmental and energy justice can produce a just transition away from a GHG-intensive economy and toward a more sustainable outcome.

7.2 Distributional, Procedural, and Recognition Justice

The three core tenets of energy justice are the assurance of distributional, procedural, and recognition justice, as shown in Exhibit 7-1 (Spurlock, Elmallah, and Reames, 2022). To aid in the understanding of the bigger picture of energy justice, the following subsections provide background on these three tenets.

Exhibit 7-1. Flow of energy justice decisions



Permission pending from (Spurlock et al., 2022)

7.2.1 Distributional Justice

Distributional justice is focused primarily on the equitable distribution of benefits and dis-benefits across communities (Spurlock et al., 2022). It is a concept focused on the well-being of individuals, which spans the gambit of human outcomes such as psychological well-being, societal well-being, and physiological well-being (Deutsch, 1975). Distributional justice delves into the nuanced context in which equity versus equality versus need may dominate in identifying unjust distributions.

Fairness is a key concept within distributional justice and can be characterized as a problem for geospatial analysis (Bouzarovski and Simcock, 2017). Across the energy supply chain, distributional justice is a problem of implied risk responsibility as well as costs and benefits (Heffron and McCauley, 2014). In addition to inequities created by a historical lack of inclusiveness is the risk that those structural deficits will compound under a changing climate. In other words, unless addressed, the deficits of the past will likely increase as the climate changes much like a revolving line of credit tends to grow faster over time when a balance is carried from one period to the next.

7.2.2 Procedural Justice

Spurlock et al. (2022) present procedural justice as essentially the effort to include all voices. This is the idea that disadvantaged communities are overburdened and underserved and their disenfranchisement can only be corrected when their voices are intentionally included in the start-to-finish process of project and policy development. In other words, stakeholder engagement must be done early and often to ensure the priorities of disadvantaged communities are codified in the priorities of the project or policy.

Procedural justice takes a more holistic view of outcomes from the perspective of group perception. Researchers break the impacts of procedural justice into three areas of effect: voice, dignitary process, and fair process. The voice effect is the positive behavior observed in communities engaged with a decision-making process when the individual feels heard. The effect of dignitary process is best described as respect. When an individual’s dignity is preserved, the community buy-in to the procedure grows. Finally, the fair-process effect describes the positive community behaviors that arise when the group perceives the existence of procedural justice. In a sense, the effect of fair process augments the effects of the dignitary process and the power of voice (Lind and Earley, 1992).

7.2.3 Recognition Justice

At its core, recognition justice deals with respect and consideration. Spurlock et al. (2022) present the concept as a demand to recognize that divergent views exist on the best pathways for energy project development and strategies to address issues of climate justice. Those views reflect the unique, diverse backgrounds of these communities who present the perspectives and opinions reflective of their histories. Incorporating those voices in the energy transition is critical to ensuring policymakers implement project development that seeks to serve all. Equitable outcomes begin with the recognition that disenfranchised communities will require effort to enfranchise and empower their members to ensure their histories and perspectives are heard in a meaningful way.

Recognition justice seeks to provide for fair representation, safety, and the general creation of an environment that is welcome to all. McCauley et al. (2013) identify issues of recognition injustice in terms of how policy might treat those characterized as "energy poor" with the classic example of the behaviors of elderly household energy use. Looking at the overall higher average energy use, United Kingdom policymakers view the issue as an education problem where the assumption was that elderly people do not understand the long run impacts of small behavior changes. The authors reveal that framing choices in way that nudged elderly households toward the intended policymaker outcome required acknowledging that older people need warmer houses for their health and well-being. Strategies for changing behavior are more effective when normative behaviors within the community, culture, or ethnicity are recognized.

7.3 Energy Justice

Commented [DN28]: Justice40 Initiative | Department of Energy

Commented [DN29R28]: I think it would be good to include other sources of applying energy/environmental justice for gas industry. Recommend reviewing DOE policy on implementing Justice 40 and addressing and developing metrics for incorporating energy justice in energy project implementation. Also be good to review API's recent report on environmental justice in oil & gas industry - https://www.api.org/news-policy-and-issues/environmental-justice

Commented [BO30R28]: Saving for future action per Friday's DOE meeting.

Anchored by the three tenets of distributional, procedural, and recognition justice, energy justice acts as a guiding concept for activism (McCauley et al., 2013). A broad literature review on the topic of energy justice (Qian et al., 2022) shows that the recent growth and focus on energy justice has quickened in pace with the effort to incorporate renewable energy on the grid. Debating the definition of energy justice has been a robust area of discussion for researchers, but there exist a few core concepts that underpin most approaches. At its heart, assuring energy justice deals with the issue of addressing energy poverty and branches out from the broader focus of environmental justice (Iwińska et al., 2021).

While focus on the justice of energy distribution is not new, it has grown in salience as the public increasingly accepts the need to transition from fossil fuels-based systems of energy production and consumption to clean alternatives. Using energy justice as a decision-making framework, Iwińska et al. (2021) outline the focus of this literature as one that seeks to consider how the policy-making framework surrounding the generation and consumption of energy can be fairer. In this sense, energy justice acts as a tool, helping to guide policy design.

On one hand, Iwińska et al. (2021) consider the energy justice concept as a "boundary object" whose conceit is to accelerate the inculcation of these principles in policymaker innovation and across all cultural boundaries—much like a change agent. On the other hand, these authors debate the merits of treating the concept as a standard rather than a boundary object. Standards on energy justice would more easily be incorporated into policy in tractable forms that are quantitative and qualitative, though likely at the loss of a unifying definition (Iwińska et al., 2021).

Digging beyond the core tenets of energy justice, Sovacool and Dworkin (2015) acutely characterize the conceptual metrics by which broader approaches to energy justice may be measured. Those include the need to measure the costs communities face with a special emphasis on the level of inequity across communities relative to the distribution of these costs. Sovacool and Dworkin (2015) also identify the need to distribute benefits to these same communities. Though it seems logical to measure the costs *and benefits* to disadvantaged and disenfranchised communities, historical focus has more often been on mitigating or compensating losers for costs rather than on how project design can seek to benefit disenfranchised communities. Their very disenfranchisement may relegate them to an after-the-event consideration (when considered at all), which highlights costs over benefits. The simple statement that benefits should be considered alongside costs may act to nudge the focus back toward before-the-event planning.

Sovacool and Dworkin (2015) list procedure as the critical element that can act to bridge the cost-benefit gap. The process by which energy project development flows can be exclusive by nature; this would naturally prohibit the participation of disenfranchised communities who, again by definition, are not empowered to advocate as robustly as the enfranchised communities.

Iwińska et al. (2021) outline the various foci of energy justice research. The current dominant topic has been renewable energy, as energy transition efforts have driven the growth of interest in energy justice. Summarizing the remainder of the subtopics of energy justice in broad terms, the research falls within the categories of energy poverty, energy policy, law, and governance.

Results from the transition away from fossil fuels are producing differentiated outcomes that vary by community. Energy justice studies reveal that some communities are clearly benefiting from the increased access to renewable energy technology and opportunities while others assume the burdens of change. Those communities that seem to be accruing the adverse health outcomes and increased cost of cleaner technology are the same historically disenfranchised peoples who often fail to reap the job gains and regional economic growth opportunities of change. Beyond this, the transition away from fossil fuel production harms local governments' ability to provide constituent services in cases where fossil fuels are dominant sources of economic activities. Nonprofit organizations tend to lead in the effort to ameliorate these inequitable outcomes (Carley, Engle, and Konisky, 2021).

Commented [RK31]: One aspect about the transition away from fossil fuel production relates to dependence of fossil fuel revenues, fiscal policy, and consequences to public service and infrastructure provision.

Pellegrini-Masini, Pirni, and Maran (2020) make the case that the prevalence of energy justice definitions inhibits the capacity of policymakers to deploy these concepts toward the greater good. They highlight several useful but nuanced approaches with Guruswamy (2010) underscoring the "energy oppressed poor" as those suffering from an inequitable distribution of energy as a resource, which is innately about distributional justice.

7.4 Energy Poverty and Energy Burden

Poverty is a dominant issue that arises often in research focused on energy. As policies are implemented to attenuate the worst effects of climate change, the focus on carbon emissions as a flow and stock[n] necessarily highlights how these costs are going to be born geospatially. Carbon mitigation policies themselves also present societal costs that are unequally burdening

[n] The term "greenhouse gases" refers to those associated with atmospheric warming; however, GHGs are not uniform in how they affect the global warming process as their lifecycles vary. Carbon dioxide is considered a stock gas as it remains in the atmosphere for long periods. As such, it builds up over time like a "stock" of gas. CH_4 is a much shorter-lived GHG. It enters the atmosphere and remains for just about 12 years. As such, it is considered a gas that "flows" through the atmosphere with short-lived warming impacts for any one unit of methane.

communities based on how much of the remaining carbon budget impoverished communities might need. But at its heart, energy justice is an issue of economic opportunity as access to safe, affordable energy is a necessity to meet basic human needs and pursue economic growth opportunities (Piwowar, 2022).

Bouzarovski and Petrova (2015) identify the criteria and conditions that drive energy poverty as the material and/or social deficit in energy services accrued by communities. The authors outline two key issues. First, deficits in domestic energy access and supply are the direct result of ineffective socio-technical mechanisms that fulfill energy demand at the household level of energy services such as heating and lighting. Second, "vulnerability thinking" often drives or exacerbates these outcomes. That is to say, the perceived likelihood of becoming impoverished can drive outcomes, frame processes, and generally lead to the undesired outcome as a result of historical perceptions or perspectives (Hall et al., 2013).

Okushima (2021) attempts to measure the "basic carbon needs" of a community. These are the total GHG emissions an individual community might bare to attain an "adequate level of domestic energy services." Okushima's case study of Japan highlighted that basic carbon needs varied based on differences in several factors within a community including the type of domestic dwelling, community demographics, and variation in climate characteristics across regions. Affluence allows people to shift away from GHG-intensive energy sources and can change basic carbon needs. Moreover, Okushima (2021) found that balancing the ability of all communities to meet their energy needs with decreases in their basic carbon needs is the critical factor for achieving some equitable progress on climate change.

The importance of energy poverty may have increased in recent years as a function of the world's increased attentiveness to climate change risks, but Campbell (1993) points to the 1970*s* oil crises as the flux point at which energy poverty challenges to political stability were revealed. Those latent risks to social cohesion were evident in communities dominated by lower incomes, access to inefficient heating technology, and sub-standard governmental guidelines for housing insulation. However, the sudden rise in oil prices catalyzed those latent risks into active disruptions that were exacerbated as policymakers introduced mechanisms to ration supply.

Campbell (1993) identifies the conceptual term "poverty" as an issue that confounds action on the problem of energy poverty. Poverty is identified as a multi-generational condition that permeates at the community-level without tangible points of action to take. To most, the state of poverty is a state of being. This is a challenge without boundaries—that formlessness tends to overwhelm policymaker action especially when considering the issue as multi-generational. Measuring those impacts on a quantifiable level is, therefore, a distinct challenge.

Energy poverty, on the other hand, is an energy infrastructure problem that capital expenditures can directly cure because household expenditures on fuel are quantifiable; therefore, a threshold exists in theory where energy poverty begins and ends (Campbell, 1993).

Campbell points to Boardman (1987) who posited that 10 percent of one's household income being spent on energy/fuel was the threshold of concern for energy poverty—a metric adopted by several others (Green et al., 2016; Lloyd, 2006; Lesser, 2015). While a large proportion of research identifies that spending above 10 percent indicated a state of energy poverty whereupon the cost of fuel consumption to meet one's energy service needs was a burden, some researchers have illustrated that threshold is 6 percent (Drehobl et al., 2020).

Follow-on research has expanded on this effort to measure energy poverty by creating a metric of threshold for energy poverty. While some countries have adopted specific metrics for measuring and comparing energy poverty (Faiella and Lavecchia, 2021), there is no clear consensus on best practices. Chapman and Scannell (2005) developed the Affordable Warmth Index based on the calculation of energy ratings to identify sources of energy that need efficiency investments by policymakers and households. Several others have made contributions, for example, Siksnelyte-Butkiene et al. (2021), Thomson and Snell (2013), Heindl (2013), Miniaci et al. (2014), Okushima (2016), and Brunner, Spitzer, and Christanell, (2012).

Regardless of the methodology for measuring energy poverty, the fundamental issue at hand is that the lack of affordable warmth changes people's basic daily routines. The onerous nature of accommodating these energy deficits tends to drive health and wealth outcomes for households (McCrone, 2015). The lack of affordable energy can bind communities to a lack of economic opportunity as they attempt to accommodate for energy deficits or their high costs, which tend to affect minorities and people of color more intensely.

Commented [DN32]: DOE's Office of Economic Impact & Diversity has come up with a methodology to measure energy poverty/burden

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The myriad impacts of energy poverty on health are too numerous to cover in this document, but Faiella and Lavecchia (2021) outline several. Overall, households with limited incomes are energy poor and suffer from subsequent negative health outcomes (Thomson et al., 2017), for example, excess deaths during wintertime (McAvoy et al., 2007) with the elderly particularly at risk (de'Donato et al., 2013) and increasing seasonal variation due to climate change compounding these risks (Healy, 2003). For healthcare systems, this increased seasonal health risk can reduce economic activity and reduce the integrity of the broader healthcare system (Wells, 2007) with compounding effects to the system over time (Torjesen, 2012).

Negative outcomes tend to accumulate across multiple community contexts, but their effect is not felt in isolation. Rather, these negative community outcomes tend to have cumulative effects that interact and compound each other with the risk of cointegrated impacts higher with LNG project development (Gislason and Andersen, 2016).

7.5 JUST ENERGY TRANSITIONS

The current energy transition presents a generational opportunity to make significant progress in ameliorating historical injustices (Wang and Lo, 2021). As technology has evolved and capital has flowed into large-scale energy infrastructure investments, a concerted effort to accrue the economic and social benefits associated with these technologies and investments in disadvantaged communities may prove fruitful in spurring a more just outcome from the energy transition. Equally possible is the ability to start mitigating the systemic injustices that have continued to plague these same communities in response to historical decision-making.

The articulation of energy transition goals varies significantly across the research literature, but it tends to boil down into a handful of broad topics.

These include poverty reduction (Lo and Broto, 2019; Koehn, 2008; Colenbrander et al., 2017), amelioration of historical energy injustices (Jasanoff, 2018; Delina and Sovacool,2018; Carley and Konisky, 2020), and opportunities for economic growth (Yang et al., 2018; Ehresman and Okereke, 2015). Wang and Lo (2021) argue that the energy transition is an apt vehicle for fixing historical wrongs if it can simultaneously account for environmental costs disadvantaged communities already suffer from, the reality that climate change will likely exacerbate these pre-existing environmental costs, and a decision-making process steeped in the tenets of assuring energy justice.

Pellegrini-Masini et al. (2020) attempt to prioritize the approach toward justice and the energy transition across four planes. First, the tradeoff in intergenerational outcomes and opportunities must be a prominent consideration for policymakers. This addresses the core reason that mitigating climate change is essential: subsequent generations should be provided the opportunity for growth and well-being that is at least commensurate with today's generations. Second, building out policy that considers energy vulnerability will help to prevent the transition from being a zero-sum game in which regional, fossil-fuel-reliant economies are left behind. In this sense, energy projects will benefit vulnerable communities. Third, transforming the social self-image of communities whose cultural identity is tied to fossil fuels must be considered to avoid confusing the energy transition with an attack on disadvantaged communities. Finally, the unavoidable damage to local communities must be accounted and compensated.

The ability to move forward into a new energy landscape that is sustainable is a direct function of the ability of policymakers to avoid repeating historical injustices; justice frameworks must be the bedrock of transition planning (Wang and Lo, 2021; Williams and Doyon, 2019). Pai, Harrison, and Zerriffi (2020) provide the framework for researchers to consider strategies for a just transition—one that preserves the well-being of fossil-fuel-reliant communities. Preserving the human capital of these communities is a critical goal for ensuring the energy transition policy provides opportunities for all. Pai, Harrison, and Zerriffi (2020) summarize more than a dozen requirements that would facilitate policymaker efforts to ensure a just transition but underscore one: the requirement of intentional effort for long-term planning with routine efforts to conscientiously engage with affected communities. Historically disenfranchised communities of people must be actively welcomed into the discussion early and often to be re-franchised and ensure their voices are heard (Weller, 2019).

7.6 Fossil Fuel Employment and Revenue

Commented [DN34]: Clean Energy Workforce Development and Manufacturing are two big priorities for DOE. Recommend making sure we have consistent or similar messaging here as the Energy Sec and FECM DASH-1

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As the United States shifts away from a GHG-intensive economy, the delicate issue of fossil fuel unemployment arises. Specifically, the risk of unemployment rising as a result of the shift away from a GHG-intensive economy is pronounced in regions where fossil fuel and other extractive-based or refining industries have historically dominated available employment opportunities and been the core driver of local economic growth in the region. The loss of those jobs represents a significant loss to local government revenues, long-term declines in the economy, and a potential cycle of population loss under which the region cannot recover.

The capacity to politicize energy transition debates is high (Healy and Barry, 2017) with GHG-intensive firms in a unique position to rally action against clean-energy projects (Goods, 2022) as a tradeoff between employment and climate policy. There is some merit to this concern from the community perspective as well. Female employment in the solar industry lags far behind male employment (Carley and Konisky, 2020) and disadvantaged or disenfranchised communities tend to bear a larger overall burden of costs even those associated with cleaner energy projects (Brock et al., 2021). To the extent that governance strategies can acknowledge the dignity of historically disadvantaged communities and groups, efforts to engage with those communities and groups in energy transition and governance strategies will be more successful and less divisive (Grossmann and Trubina, 2021).

Unions are viewed as an amenable structure for elevating and empowering the voices of disadvantaged communities in the energy transition (Pai, Harrison, and Zerriffi, 2020; Newell and Mulvaney, 2013). One reason may be in the high unionization rate of fossil-fuel industries (Pai and Carr-Wilson, 2018). Engaging with unions is in many ways a matter of practicality and the pre-existing internal structures built to advocate for their members make unions a strong vehicle for working toward a just transition[o] (Stevis and Felli, 2015). As an expansion of natural gas/LNG U.S. export capacity could limit the loss of employment for communities historically reliant on the fossil fuel industry, there exists an implicit advantage to directly approaching unions as potential enablers of cooperation with communities. Avoiding the mass loss of employment would help these communities from further decline as they tend to be areas in which the negative health and social impacts of fossil fuels are particularly pronounced.

Intentional efforts to diversify local economies would increase the resilience of local economies (Lobao et al., 2016). Notably, increasing the diversity of local economies is a positive regardless of the effort to transition away from fossil fuels. Any local economy highly dependent on one industry—particularly when that industry is as volatile as extractive-based industry—would introduce a greater resilience supportive of regional growth (Freudenburg and Gramling, 1994).

Among the opportunities a just transition presents are the ability to reduce the gender gap in regions dominated by the fossil fuel industry, increase investment into local energy infrastructure, remediate historical environmental damage, retrain the local workforce to "skill up" the region's human capital, and shore up local government revenues through economic diversification (Pai, Harrison, and Zerriffi, 2020).

In the end, just transitions are achieved when local voices are not just heard but amplified during the energy transition process. An unfortunate trend can play out that misses the mark on this issue where well-intentioned decisionmakers attempt to prescriptively advocate on behalf of disadvantaged communities. Often, policymakers advocate for the environmental protection of disadvantaged communities while neglecting to consider the calls for economic development emanating from those communities. A key example of that rests in the Canadian arctic where LNG projects that could act as local development opportunities for increasing local incomes are prevented by national policies that have banned energy projects out of the best intentions (Nicol and Barnes, 2019).

[o] The term "just transitions" originated within community-organizing efforts centered on labor unions (Eisenberg, 2018).

One obvious benefit of large-scale energy project development rests in the rents accrued from the project's completion. Treating these project benefits as a viable source of income that could be distributed to disadvantaged communities was explored in Chandrashekeran (2021), who studied indigenous populations in Australia after land repossession within Aboriginal populations. Chandrashekeran (2021) found that establishing property rights for historically disenfranchised populations is a key step in empowering collective negotiations for revenue sharing to fund reparations.

7.7 Protests and Political Activism

Excluding communities from decisions creates risks not just for disadvantaged populations, but for the completion of large-scale energy project development overall (Temper et al., 2020). The perpetuation of community disenfranchisement leaves people with a sense that the only option available for advocacy is to organize and protest. The way in which narratives are framed matters a great deal with respect to facilitating community buy-in for policy seeking to pivot away from fossil fuels.

Janzwood and Millar (2022) argue that the duality of natural gas—that it simultaneously accelerates the transition as a baseline electricity input and ensures the perpetuation of GHG reliance—creates the conditions for interpretive politics to dominate discourse around the transition. This is especially true for LNG organizations planning large energy infrastructure projects (Korkmaz and Park, 2019) and when regional economies are reliant on fossil fuels or the topic of natural gas as a "bridge fuel" is debated (Cha, 2020).

On the other side, anti-coal and anti-gas advocacy groups proved their own capacity to organize effectively in developed economies (Durand and Keucheyan, 2022). Social movements such as a the "UK Rights to Warmth" in the United Kingdom coalesced around the fight against entrenched energy poverty to some success (Walker and Day, 2012). Successful efforts to stop LNG export projects were found even in fossil fuel-friendly U.S. states such as Texas (Garrett and Sementelli, 2021) with access to social media and the strategic deployment of online networks increasing their efficacy (Correa-Cabrera et al., 2022).

The willingness to protest varies across cultures. Whereas communities within the United States that are at risk of job losses from national policies might tend to view justice as a regional tug of war that *must be* fought, research into Chinese activism shows that the Confucian perspective on justice as a collective outcome (whose goals are harmony between nature and humanity) shifts the perspective of the debate at its core (Wang and Lo, 2022). However, a nation or region's reliance on fossil fuels is not a reliable indicator of attitudes toward natural gas and LNG projects. Case in point, protestors in Canada and Norway have vehemently advocated against the expansion of oil and gas exploration despite their deep reliance on oil and gas production for both economies (Harrison and Bang, 2022). It has also been found that protests can arise in areas where there is a history of oil extraction when unconventional natural gas exploration is proposed (Chailleux et al., 2018).

The politicization of energy infrastructure can result in starkly divided factions, but the common thread of discontent that binds pro-gas and anti-gas contingencies is rooted in process.

Specifically, deficits in procedural and distributional justice tend to increase the likelihood of activism (Evensen, 2018; Temper et al., 2020).

7.8 ENERGY GOVERNANCE AND ADAPTIVE MANAGEMENT

Governance structures play a vital role in the pursuit of energy project development and the transition away from fossil fuels, but their ability to provide an equitable or just transition is not guaranteed (Moss, 2009). Incorporating the concept of just outcomes begins with the governance structures of energy project development and planning (Newell and Mulvaney, 2013). Those who are in the position of governance are in a position of authority to inculcate more equitable outcomes to benefit disadvantaged populations (Florini and Sovacool, 2009).

As Florini and Sovacool (2009) point out, governance is not simply government. While governance is an activity in which governments participate it exists as a framework for creating and maintaining processes to implement policy. This framework is the conduit for participation that brings together government, intergovernmental organizations, private sector market participants, and communities to collectively manage a process that ideally serves all groups.

Governance is necessary as a result of two issues with which economists often wrestle. One issue is that society is not capable of ensuring equitable access to public goods without some overarching set of rules to facilitate that outcome and a governance structure to provide oversight over implementation. The second issue is that any economic or social activity tends to create what economists call “externalities.” That is, there are unintended results that can occur indirectly from the consumption of goods or social interactions. The decommissioning of a coal power plant is a prime example of the need for governance to protect the public’s well-being from externalities, as an idle power plant could become the source of negative health outcomes for a community without intentional efforts to prevent such outcomes. Governance structures are necessary to deal with these two conceptual issues because there is no economic incentive to do so (Florini and Sovacool, 2009).

Perspectives can clearly vary within communities and that variation can affect governance structures (Wang and Lo, 2021). In studying international natural gas markets, Norouzi (2022) notes that the heterogeneity of individual members within a collective community implies that international natural gas market outcomes are heavily influenced by individual preferences within any collective. Community engagement is important, but it is not the magic elixir that solves the problem by itself. Ciplet and Harrison (2019) identify three conflicts that emerge in efforts to facilitate an energy transition: 1) between inclusivity and sustainability where inclusive processes that invite community engagement require more time to complete projects; 2) between sustainability and the need to recognize the unique value system for each community, which increases the complexity of sustainability goal pursuits; and 3) between equity and sustainability, meaning that the distribution of costs and benefits can conflict with project performance.

The impact of a region’s political economy can also clearly drive outcomes. Inequality is a multi-dimensional concept that varies across countries and individuals (Laurent and Zwickl, 2021). As the communist states of the Eastern Bloc exited the Union of Soviet Socialist Republics, the effort to integrate into energy markets within the European Union revealed that variations in

culture and geography dominated some preferences in energy project outcomes with respect to energy justice (LaBelle, n.d.). On the other hand, a study of sub-Saharan African nations revealed a positive relationship between democracy, energy justice, and growth (Opoku and Acheampong, 2023). Cultural differences aside, income and wealth inequality may drive many of the outcomes. Studies of European Union attitudes toward sustainability policies show that 41 percent country-level variance in negative attitudes is correlated with differences in wealth and income (Pellegrini-Masini et al., 2021).

In short, the lack of consideration for energy justice issues within the global framework of energy governance will likely just perpetuate historical disadvantages within communities (Symons and Friederich, 2022). This is a function of existing power structures within current governance structures. Beyond that, Symons and Friederich (2022) show that the political sovereignty of communities making independent decisions over energy project development will always result in outcomes that serve each group's self-interest and ignore the externality problems. Without intentional adjustments to governance that deal with these structural problems, the current paradigm will continue to create winners and losers and perpetuate the current disenfranchisement of some communities.

Good governance strategies for energy project development require support from the government, reliable capital and operational funding, diversification goals for the economy, and diverse coalitions (Wang and Lo, 2021; Cha, Wander, and Pastor, 2020). Finally, the creation of ownership stake opportunities at the onset of project development for disadvantaged communities is critical to ensuring that the tradeoffs between disenfranchised communities and the regional benefits of energy projects ameliorate losses. Greater rates of acceptance have been found to exist within communities with larger ownership stakes in energy projects (Hogan et al., 2022).

7.9 Sustainable Development

The desire to balance environmental protection and economic development in disadvantaged and frontline communities has led to the championing of a concept called "sustainable development." Summarized broadly, the idea is to balance the needs of current generations without harming the well-being of future generations. Within this movement, the needs of today's impoverished communities are heavily weighted under the theory that gains in wealth and income of today's generation beget gains in tomorrow's generation. In other words, the benefits of economic development compound over generations (Poppel, 2018).

In practical use, the concept of sustainability can be vague (Grossmann et al., 2022). One oft-missing area of focus is the tradeoff between environmental protection advocacy for disadvantaged communities and advocacy with these same communities for energy justice and sustainable development. The concept of embedded sustainable development outlines criteria for energy project development to be measured in terms of how energy justice efforts compare to the energy privilege of communities (Ciplet, 2021).

In 2015, the United Nations outlined a list of 17 Sustainable Development Goals that define the focus of sustainability as a practice (United Nations, 2015). Oriented toward 2030 outcomes, the 17 outcomes broadly fall into Barbier's (1987) canonical "three systems" approach to

process development: environmental, social, and economic. Broadly speaking, the 17 goals break down into the promotion of clean water and sanitation services alongside sustainable cities and sustainable economic growth with full employment as well as the sustainable development of natural resources. They also promote the end to food insecurity and poverty, greater levels of societal health and well-being, lifelong inclusive/equitable educational opportunities, and gender equality, as well as strong judicial and governmental institutions. Finally, the United Nations (2015) advocates for the proactive implementation of climate change policy that results in energy infrastructure resilience where communities have access to reliable and affordable clean energy.

Cherepovitsyn and Evseeva (2020) proffer several criteria to promote sustainable development within the context of LNG project development in the arctic—an area currently receiving a great deal of attention for energy development projects. The authors note the importance of sustainable development in the arctic as it is home to over 20 percent of the world's hydrocarbon resources. To promote sustainable outcomes, they propose seven criteria of sustainable development goals[p]:

- Project development must minimize environmental impacts at the construction and operation site
- Natural resource use should be efficient
- Local community support is paramount as is the effort to preserve indigenous culture and heritage
- Long-run regional economic gains that benefit and reflect stakeholder expectations should be prioritized
- Larger energy infrastructure development goals are achieved
- Innovations to industry technology are achieved
- Strengthening the regional LNG market relative to the global network is achieved

7.10 CONCLUSION

Historical disenfranchisement of communities has often resulted in the creation of winners and losers with respect to policy impacts. To the extent that policy has created the conditions under which disadvantaged communities arise, those policies have likely been rooted in a fundamental lack of inclusivity in the planning and implementation processes of project development. As the United States continues to embark on a transition away from a GHG-intensive economy, the chance to right those historical wrongs presents itself.

DOE deploys the Climate and Economic Justice Screening Tool to identify disadvantaged communities. To do so, the tool pulls in geographic information system data on the universe of communities whose boundaries are defined by the U.S. Census. These communities are identified as disadvantaged if that census tract meets the criteria for disadvantage in one of the

[p] Note that while the framework for measuring outcomes by Cherepovitsyn and Evseeva (2020) focuses on the arctic, this approach may be prudent for any LNG project development strategy. As such, the seven points have been modestly edited to apply more broadly.

categories describing burden or if that community resides within the boundary of a federally-recognize tribe.

The panoply of burdens fall within a framework of several categories. The threshold for being considered disadvantaged under the Climate Change category is that the census tract is at the 90th percentile for agriculture loss, building loss, population loss, or flood and wildfire risk. For Energy, the census tract is at the 90th percentile for energy costs. For Health, the census tract is at the 90th percentile for asthma, diabetes, heart disease, or low life expectancy. For Housing, the census tract is at the 90th percentile for green space deficits, indoor plumbing, or lead paint exposure as well as they have experienced historical disinvestment in housing. For Legacy Pollution, the census tract is at the 90th percentile of exposure to facilities that have dealt with hazardous waste, former defense sites, are proximal to a superfund site or a risk management facility. For Transportation, the census tract is at the 90th percentile for exposure to various environmental particulates, face barriers to transportation access, or barriers due to volume. For Water and Wastewater, the census tract is at the 90th percentile for exposure to storage tanks or releases underground, or the discharge of wastewater. For Workforce Development, the census tract is at the 90th percentile for isolation by their linguistic background, poverty, unemployment, or an overall lower median income.

Currently, the tool identifies roughly 27,251 communities at the census tract level. The deployment of tools like this during the energy transition is key, particularly during the early planning stages, in creating the approach for community outreach, and in the effort to structure governance strategies. Identifying where disadvantaged communities are provides the high-level understanding into where deficits in outreach and inclusion have likely exacerbated the pervasiveness of disadvantage. In doing so, concerted efforts to bring these voices into the development of large-scale energy infrastructure projects related to natural gas/LNG market opportunities is key.

The calls to advocate for energy justice during this transition have grown as the salience of climate change threats grows. Achieving a just transition is largely a functioning of process. The once-in-a-lifetime opportunity to restructure current processes around the core concepts of distributional, procedural, and recognition justice is significant. Re-framing the foundations upon which critical U.S. energy infrastructure is built by bringing diverse voices and stakeholders to the planning table will help to ensure that the best laid plans produce results that facilitate the growth for all, not just some.

To do so, there is a need to accept the existence of frictions innate to energy justice and energy poverty. Providing economic growth opportunities in GHG-intensive regional economies is as paramount as the need for ensuring reliable, affordable, and clean energy for those suffering from a historic lack of energy access. This may require adjusting the method of measuring the benefits and costs of large-scale U.S. energy infrastructure investments. The implementation of the Biden-Harris Administration's Justice40 initiative speaks to this effort.

This chapter provides the framework for pursuing inclusivity goals in its discussion of energy justice and energy poverty. The energy transition is presented as a catalyst for pursuing change with the intended outcome being a just transition for all. In the end, the vehicle for applying

energy justice and energy poverty goals rests in the inclusive design of energy governance structures.

The literature base of energy justice and energy poverty within the space of natural gas and LNG market development is strong and growing. With intentionality, the authors of future research can help to ameliorate those historical disenfranchisements and provide a framework for the kind of shared prosperity that induces strong growth for all.

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Document 59 - Attachment 2, is not included in this production and will be included in a future production.

From: Harker Steele, Amanda J.
Sent: Fri, 16 Jun 2023 18:46:03 +0000
To: Curry, Thomas; Sweeney, Amy; Skone, Timothy; Francisco De La Chesnaye
Cc: Wallace, Robert T. (CONTR); Adder, Justin (NETL)
Subject: RE: LNG Regulatory Analysis Support FWP - Task 4 Env. Review Draft #1
Attachments: Draft_Env.Review_Task4_LNG_LNGRegAnalysisSupport_FWP-DraftPreDecisional_6_16_23.docx

Hi Tom, Amy, and Tim,

*DRAFT*DELIBERATIVE*PRE-DECISIONAL*

Please find the first draft of Chapter 7 for the update to the 2014 Addendum to the Environmental Review attached. We look forward to receiving your feedback.

Sincerely,
Amanda J. Harker Steele, Ph.D. (she/her)
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From: Harker Steele, Amanda J.
Sent: Friday, June 9, 2023 3:56 PM
To: Curry, Thomas <thomas.curry@hq.doe.gov>; Sweeney, Amy R <amy.sweeney@hq.doe.gov>; Skone, Timothy J <timothy.skone@hq.doe.gov>; Francisco De La Chesnaye <francisco.delachesnaye@onlocationinc.com>
Cc: Wallace, Robert T. (CONTR) <Robert.Wallace@netl.doe.gov>; Adder, Justin M. <Justin.Adder@netl.doe.gov>
Subject: LNG Regulatory Analysis Support FWP - Task 4 Env. Review Draft #1

Hi Tom, Amy, and Tim,

*DRAFT*DELIBERATIVE*PRE-DECISIONAL*

Good afternoon! Please find the first draft of the update to the 2014 Addendum to the Environmental Review attached. Chapters 1 through 6 are ready for your review. We should have Chapter 7 ready for your review by next Friday.

We look forward to receiving your feedback but are wondering if it would be possible to receive all comments at once?

Thank you!

Sincerely,

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DRAFT*DELIBERATIVE*PRE-DECISIONAL

NATIONAL ENERGY TECHNOLOGY LABORATORY

ENVIRONMENTAL IMPACTS OF UNCONVENTIONAL NATURAL GAS DEVELOPMENT AND PRODUCTION

June 9, 2023

DOE/NETL-2014/1651

Preliminary – Do Not Cite or Quote

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Commented [RW2R1]: Yes.

Commented [HSAJ3R1]: We will update once finalized. We will also remove any instances of DRAFT*DELIBERATIVE*PRE-DECISIONAL once finalized as well.

*DRAFT*DELIBERATIVE*PRE-DECISIONAL*

Disclaimer

Hartej Singh[2]: *Writing – Original Draft;* **Michael Marquis**[2]: *Writing – Original Draft;* **Odysseus Bostick**[2]: *Writing – Original Draft;* **Robert Wallace**[2]: *Writing – Original Draft;* **Amanda Harker Steele**[1*]: *Supervision*

[1]National Energy Technology Laboratory (NETL)
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The authors wish to acknowledge the excellent guidance, contributions, and cooperation of the NETL staff, particularly:

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Commented [RWSR4]: Yes

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TABLE OF CONTENTS

LIST OF EXHIBITS

ACRONYMS AND ABBREVIATIONS

ADEQ	Arkansas Department of Environmental Quality
AEO	Annual Energy Outlook
ANGA	America's Natural Gas Alliance
API	American Petroleum Institute
AR5	IPCC Fifth Assessment Report
B	Billion
bbl	Barrel
Bcf	Billion cubic feet
BLM	Bureau of Land Management
BMP	Best management practice
BPC	Bipartisan Policy Center
Btu	British thermal unit
CBM	Coalbed methane
CFR	Code of Federal Regulations
CH_4	Methane
CMSC	Citizens Marcellus Shale Coalition
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_2e, CO_2-eq	Carbon dioxide equivalent
CRS	Congressional Research Service
DOE	Department of Energy
DOI	Department of the Interior
EDF	Environmental Defense Fund
EIA	Energy Information Administration
EPA	Environmental Protection Agency
ERP	Energy Resources Program
EUR	Estimated ultimate recovery
ft, FT	Foot
g	Gram
gal	Gallon
GAO	Government Accountability Office
GHG	Greenhouse gas
GWP	Global warming potential
GWPC	Groundwater Protection Council
ha	Hectare
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
kg	Kilogram
kJ	Kilojoule
km	Kilometer
km^2	Square kilometers
L	Liter
LCA	Life cycle analysis
LNG	Liquefied natural gas
M	Magnitude (Richter Scale)
Mcf, MCF	Thousand cubic feet
mg	Milligram
mi^2	Square mile
min	Minute
MIT	Massachusetts Institute of Technology
MJ	Megajoule
MM	Million
MMcf	Million cubic feet
MWh	Megawatt hour
N/A	Not applicable, not available
N_2	Nitrogen
N_2O	Nitrous oxide
NAS	National Academy of Sciences
NETL	National Energy Technology Laboratory
NGL	Natural gas liquids
NOAA	National Oceanic and Atmospheric Administration
NOV	Notice of violation
NO_x	Nitrogen oxides
NPS	National Park Service
NRC	National Research Council
NSPS	New Source Performance Standards
NYSDEC	New York State Department of Environmental Conservation
O_2	Oxygen
ODNR	Ohio Department of Natural Resources
OGS	Oklahoma Geological Survey
ONE Future	Our Nation's Energy Future
PM	Particulate matter
PRV	Pressure release valve

R&D	Research and development
REC	Reduced emission completion
RFF	Resources for the Future
scf	Standard cubic foot
SDWA	Safe Drinking Water Act
SEAB	Secretary of Energy Advisory Board
SF_6	Sulfur hexafluoride
SO_2	Sulfur dioxide
STAR	EPA's Science to Achieve Results
STRONGER	State Review of Oil and Natural Gas Environmental Regulations
T	Trillion
T-D, T&D	Transmission and distribution
Tcf	Trillion cubic feet
TDS	Total dissolved solids
TSS	Total suspended solids
TWDB	Texas Water Development Board
U.S.	United States
UIC	Underground Injection Control
USFS	U.S. Forest Service
USGS	U.S. Geological Survey
VOC	Volatile organic compound
WRI	World Resources Institute
yr	Year

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EXECUTIVE SUMMARY

The Department of Energy's (DOE) Natural Gas Regulatory Program is responsible for granting authorizations to import and/or export natural gas from and/or to foreign countries. An important dimension of considering whether to grant such authorizations is how the additional natural gas production and transport activities needed to support these exports and/or imports would impact the environment. As such, impacts are factors affecting the public's interest.

Although fundamental uncertainties exist regarding the exact amount of production and transport activities that would occur in response to additional authorizations for exports and/or imports of natural gas being granted, it is probable that both conventional and unconventional natural gas markets would be impacted. Accordingly, the DOE prepared has prepared this update to the 2014 Addendum to Environmental Review Documents Concerning Exports of Natural Gas from the United States (hereafter the 2014 Addendum) to provide the public with an improved understanding of the potential environmental impacts associated with such activities (DOE, 2014).

While DOE has made projections about the additional natural gas production that may result, we cannot estimate with certainty where, when, or by what method any additional natural gas would be produced/consumed/exported in response to the authorizations. Therefore, the DOE cannot meaningfully analyze the specific environmental impacts associated with such activities. As such, similar to the 2014 Addendum, this report provides only a review of the profusion of peer-reviewed, scientific literature produced related to the potential environmental consequences of expanding natural gas production and related activities.

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These publications build on a strong body of existing literature that traces the evolution of these resources from their conceptual stages in the 1970s to the technology advancements that started the shale gas boom in the early 2000s. Between 2009 and 2022, government, industry, academic, scientific, non-governmental, and citizen organizations added a substantial body of literature on the environmental impacts that could result from continuing the development of shale gas, tight gas sands, and coalbed methane resources, as well as liquified natural gas.

This report summarizes the current state of published descriptions of the potential environmental impacts of unconventional natural gas upstream operations within the Lower 48 United States. As a survey of the literature, this report is by no means exhaustive. The sources cited are all publicly available documents. Multiple publications on similar topics are compared based only on their technical and methodological distinctions. No opinion or endorsement of these works is intended or implied.

This report is divided into chapters that each contain a separate section of references so that each type of environmental impact can be explored further. The types of environmental impacts that are documented in this review include the following:

- Greenhouse gas (GHG) emissions and climate change (Chapter 2)
- Air quality (Chapter 3)
- Water use and quality (Chapter 4)

- Induced seismicity (Chapter 5)
- Land Use and Development (Chapter 6)
- Environmental & Social Justice (Chapter 7)

In addition to containing information on potential environmental impacts this report provides some background information on domestic natural gas production.

CHAPTER 1 – BACKGROUND

Innovations in existing oil and gas exploration and production technologies revolutionized unconventional natural gas production in the United States (U.S.), particularly in shale formations. Unconventional resources, including shale, tight sands, and coal beds, can be found in more than half of the Lower 48 states; overall production from these resources is forecast to continue growing in the coming decades so that by 2040 half of domestic natural gas production is supplied by unconventional resources. The combined effects of government policies, private sector entrepreneurship, and high natural gas prices spurred advances in horizontal drilling, hydraulic fracturing, and seismic imaging that have opened long-sought energy resources. Unconventional natural gas resources not only make up for declining conventional gas production, but increasing unconventional production is contributing to increased use of gas for power generation, manufacturing, transportation, and residential and commercial heating. These advances swept domestic energy production so fast that between 2009 and 2014, U.S. companies reversed plans to import liquefied natural gas, and many are now proposing exports. Continued increases in production are now most likely to come from the major shale plays, with stable production (as a percentage of total gas production) from tight sands and coal beds. Federal, state, and local governments are re-evaluating statutory and regulatory frameworks, and multiple organizations, separately and in collaboration, are conducting continuing research and development (R&D) to help develop best practices and minimize environmental impacts.

Commented [HSAJ7]: Tim/Tom/Amy – Please let us know if you'd like to see this information reported here. It is mostly repetitive of what is included below for each chapter but does introduce the reader to the various topics considered.

Commented [HSAJ8]: SA Team – Because much of the information provided in the ES is also included below, I've added my comments to the chapters themselves rather than the ES. Please make sure to update the ES to reflect any changes in the next iteration depending on the preferences of Tom/Amy/Tim.

CHAPTER 2 – GREENHOUSE GAS EMISSIONS AND CLIMATE CHANGE

GHG emissions are released by the natural gas supply chain—the extent to which these emissions contribute to climate change has been investigated by government and university researchers. There are five major studies that have accounted for the GHG emissions from upstream natural gas, which include the construction and completion of gas wells, as well as subsequent production, processing, and transport steps. While several studies have been conducted on this topic, these five studies represent the breadth of all-natural gas life cycle work and point to the methane (CH_4) emissions from unconventional well completions and workovers[a] as a key difference between the GHG profiles of conventional and unconventional natural gas. Other key emissions occur during steady-state operations, such as emissions from compressors and pipelines. The assumptions and parameters of the five studies vary, but given

[a] "Workover" is a generic industry term for a variety of remedial actions to stimulate or increase production. As applied here to shale gas wells, it means hydraulic fracturing treatments after the initial drilling and first hydraulic fracturing of the well.

their uncertainties, four of the five studies conclude that the GHG emissions from a unit of delivered unconventional natural gas are comparable to (if not lower than) those from a unit of conventional natural gas. The fifth study concludes that the high CH_4 emissions from unconventional well completion and a lack of environmental controls at unconventional extraction sites translates to higher GHG emissions from unconventional natural gas than from conventional natural gas.

CHAPTER 3 – AIR QUALITY

GHG emissions from natural gas systems have received significant attention in current literature; however, they are not the only type of air emission from natural gas systems. The two key sources of non-GHG emissions are:

- *Uncaptured Venting*: Releases natural gas, which is a source of volatile organic compound (VOC) emissions.
- *Engine Fuel Combustion*: Produces a wide variety of air emissions, including nitrogen oxides (NO_x), carbon monoxide (CO), sulfur dioxide (SO_2), and particulate matter (PM)

VOCs and NO_x react in the lower atmosphere to produce ground-level ozone, a component of smog that adversely affects human respiratory health. The reaction between VOCs and NO_x is unique because it represents an interaction between two emission sources (in this case, uncaptured venting and fuel combustion). The other emissions from fuel combustion have a variety of human health and ecological impacts. CO affects human health by reducing the oxygen-carrying capacity of blood. SO_2 leads to soil or surface water acidification (via acid rain). PM is linked to poor heart and respiratory health (EPA, 2012; GAO, 2012).

CHAPTER 4 – WATER USE AND QUALITY

In the broadest terms, the literature describes water quality and the treatment and management of wastewaters as the central issue in the eastern states, where water is abundant. To the west, where drier climates can limit the availability of freshwater, and deep underground injection wells for wastewater disposal are more readily available, the central issue is the availability of water for drilling and hydraulic fracturing and the impacts this could have on established users. Drilling and hydraulically fracturing a shale gas well can consume 2–6 million gallons of water; local and seasonal shortages can be an issue, even though water consumption for natural gas production generally represents less than 1 percent of regional water demand. Water quality impacts can result from inadequate management of water and fracturing chemicals on the surface, both before injection and after (as flowback and produced water). Subsurface impacts can result from the migration of fracturing fluids, formation waters, and CH_4 along well bores and through rock fracture networks. Management and disposal of wastewaters increasingly includes efforts to minimize water use and recycling and re-use of fracturing fluids, in addition to treatment and disposal through deep underground injection, with the risk of induced seismicity.

CHAPTER 5 – INDUCED SEISMICITY

Induced seismicity is ground motion (earthquakes) caused by human activities. Earthquakes have been detected in association with oil and gas production, underground injection of waste waters, and possibly with hydraulic fracturing. Hydraulic fracturing involves injecting large volumes of fluids into the ground. These injections are short-lived and are injected at lower pressures, so it is likely that they do not constitute a high risk for induced seismicity that can be felt at the surface. In contrast to hydraulic fracturing, wastewater disposal from oil and gas production, including shale gas production, is typically injected at relatively low pressures into extensive formations that are specifically targeted for their porosities and permeabilities to accept large volumes of fluid. Case studies from several states indicate that deep underground fluid injection can, under certain circumstances, induce seismic activity (NRC, 2012; GWPC, 2013).

CHAPTER 6 – LAND USE AND DEVELOPMENT

Although not as extensively documented as other environmental impacts, like water quality and GHG emissions, land use and development impacts that have been discussed in the literature include property rights and use of public lands, local surface disturbance, cumulative landscape impacts, habitat fragmentation, and traffic, noise, and light. Concerns have been expressed with competing uses for public lands, the cumulative impacts of multiple industries (e.g., timber and tourism), and denial of access to areas with active operations. Surface disturbance involves not only site preparation and well pad construction, but also road, pipeline, and other infrastructure development. The cumulative impacts of surface disturbance can extend over large areas and can also result in habitat fragmentation that impacts both plant and animal species and can result in population declines. Mitigation options include adoption of best practices for site development and restoration, avoidance of sensitive areas, and minimization of disturbed areas. Development on federal land is guided by an extensive set of land use stipulations designed to mitigate these effects. As development and production operations proceed, local residents can be confronted with increased truck traffic, sometimes more than 1,000 truck trips per well, and additional noise and light as construction, development, drilling, and production typically proceed 24 hours per day. Vertical wells require spacing of 40 acres per well, the drill pads from which each horizontal well originates require spacing of 160 acres per well. A single square mile of surface area would require 16 pads for 16 conventional wells, while the same area using horizontal wells would require a single pad for 6–8 wells (NETL, 2009).

CHAPTER 7 – SOCIAL JUSTICE AND NATURAL GAS/LIQUEFIED NATURAL GAS MARKET DEVELOPMENT

TBD

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REFERENCES

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1 BACKGROUND

Innovations in existing oil and gas exploration and production technologies revolutionized unconventional natural gas production in the United States (U.S.), particularly from shale formations. Unconventional natural gas resources not only make up for declining conventional natural gas production but have also contributed to an increased use of natural gas for power generation, manufacturing, transportation, and residential and commercial heating. Federal, state, and local governments are re-evaluating statutory and regulatory frameworks, and multiple organizations, separately and in collaboration, are continuing to conduct research and development (R&D) to help develop best practices and minimize environmental impacts.

1.1 UNCONVENTIONAL NATURAL GAS RESOURCES

In current usage, three types of reservoirs comprise unconventional natural gas resources: shale gas, "tight" (low permeability) sandstones, and coalbed methane (CBM). A fourth type of reservoir—methane hydrates—is also used (DOE, 2011). The dispersed nature of the resources in these reservoirs is one of the reasons for calling them unconventional. The gas (and oil) in these reservoirs is less concentrated than natural gas in conventional reservoirs where the gas has accumulated in geologic traps. Lower permeabilities make unconventional natural gas more difficult to extract. Implications of low permeability include the need for greater scales of operations and either more, or directional, wells to contact the larger areas of production in target formations.

As its name suggests, shale gas is found in shale which is a sedimentary rock consisting of mainly clay and clay-sized particles. The crystalline structures of clay minerals form in thin, parallel sheets, somewhat like the skin of an onion. Small flakes of clay carried by streams and rivers settle in low-energy geologic environments like tidal flats and in deep ocean basins where they fall flat and parallel to one another. As these sediments are covered and buried, they are compacted into thin layers with low permeabilities. Like pages in a book, these layers restrict fluid flow, especially vertically across the layers. At the same time, microscopic bits of organic matter, plant and animal debris that were deposited with the clay flakes, decay, and under the heat and pressure of deep burial, form natural gas and liquid hydrocarbons. The low permeability traps the gas and hydrocarbons in the shale, so the shale must be fractured to increase the permeability and allow the gas to flow into wells (NETL, 2009a).

Organic-rich shale formations are widespread across most parts of the world because shale is found in all sedimentary basins and can make up to 80 percent of the sediments in a basin. In many cases, enough is already known about shale formations that little precise exploration is needed as most operators are already aware of the shale gas reserves that exist at a given location. At the same time, operators may not be able to estimate the technically and economically recoverable resources at a reserve until wells have been drilled and tested. Shale formations each have unique geologic characteristics, as such within each formation there are differences that create "sweet spots" for production.

Dozens of gas-bearing shale formations are in sedimentary basins across the United States. Some areas like the Appalachian Basin, the Michigan Basin, and the Illinois Basin have long

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"Unconventional natural gas resources primarily comprise three types of reservoirs: shale gas, "tight" (low permeability) sandstones, and coalbed methane (CBM) histories of natural gas production. With improvements in unconventional technologies such as horizontal drilling and hydraulic fracturing, plays like the Barnett, Fayetteville, Haynesville, Marcellus, and Woodford have witnessed growth in the number of unconventional wells being drilled in addition to existing conventional wells.

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"Tight gas" reservoirs were defined in the 1970s by the federal government as having a permeability to gas flow of less than 0.1 millidarcy (a unit to measure the permeability of rock to determine which gas wells would be eligible for tax credits to encourage production). They are not necessarily deposited differently than conventional sandstone reservoirs but may have lower permeabilities due to more intensive cementing by mineral precipitates. A more technical definition might be "a reservoir that cannot be produced at economic flow rates nor recover economic volumes of natural gas unless the well is stimulated by a large hydraulic fracture treatment, by a horizontal wellbore, or by use of multilateral wellbores" (Holditch, 2006).

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Like conventional sandstone gas reservoirs, tight gas sands form as gas from organic-rich source rocks (like shales) migrates into the sands and is trapped. Like shale gas formations, the low permeabilities mean that tight sand formations must be stimulated to produce commercial quantities of gas. However, once drilled and stimulated, tight gas sand reservoirs tend to have better production factors than shale reservoirs (IEA, 2012). Tight gas sand plays are less extensive than shale plays, with nearly half of the estimated domestic tight sand reserves being located in the Green River, Piceance, and Uinta Basins in Colorado and Utah, and the East Texas Basin (DOE, 2011).

1.2 Technology Advances and Adaptation

Wang and Krupnick (2013) recount the history of the economic, policy, and technology developments that led to large-scale U.S. shale gas production. Their explanation (intended for international stakeholders) of the advent of the U.S. shale gas boom offers a case study of the interactions among government policies, private sector entrepreneurship, technology innovations, land and mineral rights ownership structures, and high gas prices that helped create the boom. In the late-1970s, the United States faced natural gas supply shortages, high prices, and declining prospects for additional conventional natural gas production. The federal government recognized that private corporations lacked incentives to make large-scale, high-risk research and development (R&D) investments for the industry.

To compensate for the difficulty in protecting and patenting new technologies in the oil and gas industry, the federal government funded R&D programs and provided tax credits to promote the development of unconventional resources. Shale gas production from the Barnett Shale region of Texas increased from the early 1980s to the late 1990s, after Mitchell Energy invested a large amount of money in the area. The Barnett Shale was not included in early assessments of potential natural gas resources prior to this time. As a nation, the United States offered favorable geology, water availability, private land and mineral ownership rights, structured energy markets, and existing infrastructure to translate the success in the Barnett into greatly increased natural gas production from other shale plays (Wang and Krupnick, 2013).

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Natural gas production from unconventional resources became economically viable due to advances in development and production technologies, leading to large-scale utilization of resources that had historically been uneconomic to extract (Jackson et al., 2011). Advances in horizontal drilling equipment and hydraulic fracturing techniques allowed greater access to unconventional reservoirs. A key innovation for shale formations was the addition of very fine grains of sand, known as proppants, which are used to hold the fractures open allowing trapped gas to flow into a well (CRS, 2009). Jackson et al. (2011) estimated that a single horizontal well is two to three times more productive than a single vertical well and can reach resources two miles away from the well pad.

However, neither of these technologies (horizontal drilling equipment and hydraulic fracturing) are new. Horizontal drilling has been used since the 1930s, originally to drill from land into formations under the seabed and with advancements in the early 1980s became more commercially viable. Hydraulic fracturing was developed in the 1950s and has been applied to shale gas wells since the mid-1980s (NETL, 2009a). The Interstate Oil & Gas Compact Commission estimates that 90 percent of oil and gas wells in the U.S. use hydraulic fracturing (Jackson et al., 2011). Estimates from industry data indicate that hydraulic fracturing has been used in more than a million wells in all 33 states that produce oil and gas (The Horinko Group, 2012). Exhibit 1-1 illustrates these processes in a representative shale gas well.

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Exhibit 1-1. Horizontal drilling, hydraulic fracturing, and well construction

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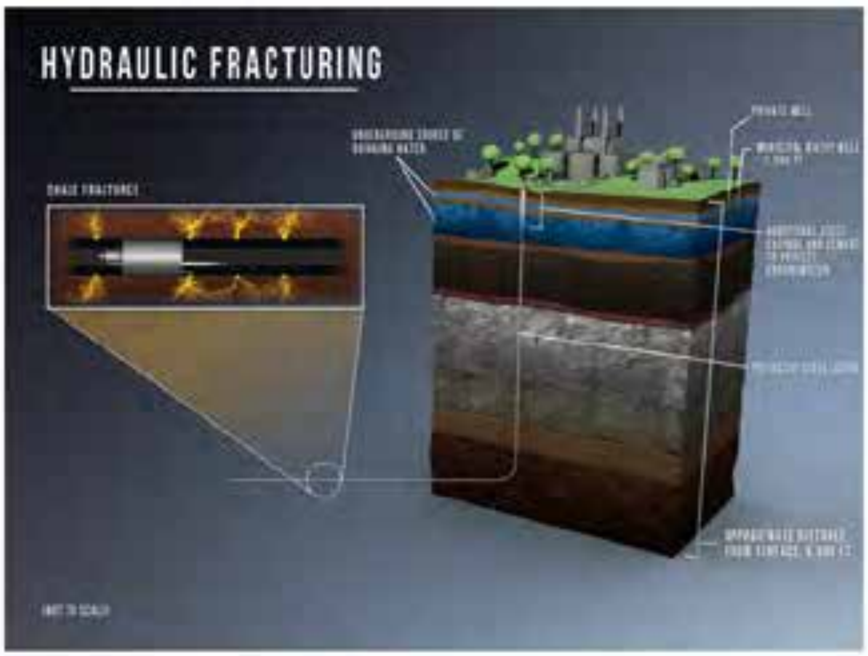

Fracturing fluids used for hydraulic fracturing commonly consist of mostly water and sand along with other chemicals and additives (NETL, 2009a). The specific additives, and the proportion of each, depend on the formation that is being fractured. These additives function as friction reducers, biocides, oxygen (O_2) scavengers, stabilizers, and acids, all of which are necessary to optimize shale gas production (NETL, 2009a). The composition of these fluids and the purposes of the additives are described in more detail in Chapter 4 – Water Use and Quality.

1.3 Unconventional Reserves and Production

There remains significant uncertainty in the estimates of the total technically recoverable natural gas reserves located in the Lower 48 states. Estimates range widely from 2,417.6 trillion cubic feet (Tcf) in the U.S. Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2022 (2022a), to 2,650 Tcf in the Colorado School of Mines' Potential Gas Committee (2021). Differences in these estimates are due to difference combinations of data and different assumptions about policies, technologies, future demand, prices, and macroeconomic conditions being used. For example, some states may continue to limit access to these resources. On the other hand, continuing technological advancements could increase recovery rates and lower production costs (BPC, 2013).

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The Government Accountability Office (GAO) (2012a) analyzed EIA data and concluded that actual shale gas production grew from 1.6 Tcf to 7.2 Tcf between 2007 and 2011, over 75 percent of which came from the Barnett, Fayetteville, Marcellus, and Haynesville Shale plays. With increasing development, EIA (2022b) forecasts a 15 percent net increase in natural gas production between 2022 and 2050 in response to increased development of unconventional resources including shale gas, tight gas, and CBM. EIA also estimates that the largest contributor to this overall growth will be production from shale gas. EIA estimates that in 2022, U.S. dry natural gas production from shale formations was about 28.5 Tcf and equal to about 80 percent of total U.S. dry natural gas production in 2022. Tight gas and CBM production will each increase by about 25 percent but their contributions to total production will decrease slightly, overshadowed by shale. Growth in CBM production is not expected to materialize until after 2035, when prices and demand levels rise enough to promote further drilling.

1.4 Best Practices

In 2011, the Secretary of Energy formed a subcommittee of the Secretary of Energy Advisory Board (SEAB) (2011a) to make recommendations to address the safety and environmental performance of shale gas production. In August 2011, the Shale Gas Production Subcommittee released its first 90-day report presenting 20 recommendations intended to reduce the environmental impacts of shale gas production. (SEAB 2011a) The Subcommittee stressed the importance of continuous improvement based on best practices and tied to measurement and disclosure. The recommendations were made in ten areas (SEAB, 2011a):

- Improve public information about shale gas operations: create a portal to share public information, including data from state and federal regulators.
- Improve communication among state and federal regulators: continue annual support to State Review of Oil and Natural Gas Environmental Regulations (STRONGER) and the Groundwater Protection Council (GWPC).

- Improve air quality: take measures to reduce emissions of air pollutants, ozone precursors, and CH4methane.
- Protect water quality: adopt a systems approach to water management based on consistent measurement and public disclosure.
- Disclose fracturing fluid compositions: accelerate progress in disclosure of all chemicals used in fracturing fluids.
- Reduce use of diesel fuel: reduce use of diesel engines for surface power and replace with natural gas or electric engines where possible.
- Manage short-term and cumulative impacts to communities, land use, wildlife, and ecologies: pay greater attention to combined impacts from drilling, production, and delivery activities and plan for shale development impacts on a regional scale.
- Organize for best practice: create an industry organization for continuous improvement of best practice.
- Identify research and development needs: significantly improve efficiency of shale gas production through technical advances.

1.5 U.S. Statutory and Regulatory Framework

Multiple federal agencies have authority for unconventional natural gas development and production. The Environmental Protection Agency (EPA) regulates deep underground injection and disposal of wastewater and liquids under the Safe Drinking Water Act (SDWA), as well as air emissions under the Clean Air Act. The Occupational Safety and Health Administration is responsible for quantifying standards for application in the oil and gas industry. On public lands, federal agencies are responsible for the enforcement of regulations that apply to unconventional gas wells. These agencies include EPA, the Department of the Interior (DOI) Bureau of Land Management (BLM), the National Park Service (NPS), the Occupational Safety and Health Administration, and the U.S. Forest Service (USFS). The BLM is responsible for protecting the environment on its lands during all oil and gas activities. The USFS is responsible for managing development on federally owned lands along with the BLM (NETL, 2009a). If any types of oil and gas activities are proposed to take place within national park boundaries, the NPS may be able to apply regulations to protect park resources and visitor values, but the applicability of those regulations depends on each case.

Exhibit 1-2 gives some examples of the applicability of federal regulations to unconventional natural gas development (CRS, 2009; NETL, 2009a).

Exhibit 1-2. Selected federal regulations that apply to unconventional oil and gas development

Regulation	Applicability
Clean Air Act	Places requirements on air emissions from sources of emissions at well sites. Addresses compliance with existing and new air regulations, often delegated to local and state agencies. Generally, there is no distinction made between conventional and unconventional wells under the Clean Air Act.
Comprehensive Environmental Response, Compensation, and Liability Act	Only applies if hazardous substances besides crude oil or natural gas are released in quantities that require reporting. Natural gas releases do not require notification under the Comprehensive Environmental Response, Compensation, and Liability Act, but other hazardous substances may be released in reportable quantities during natural gas production.
Clean Water Act	Pollutant limits on produced water discharge under the National Pollutant Discharge Elimination System; storm-water runoff containing sediments that would cause a water-quality violation to require permits under Clean Water Act decisions. Beneficial uses of surface waters are protected under Section 303.
Emergency Planning and Community Right-to-Know Act	Facilities storing hazardous chemicals above the threshold must report such and provide a Material Safety Data Sheet to officials and fire departments.
Endangered Species Act	Section 7 prohibits federal agencies from taking any action that is likely to jeopardize the continued existence of any endangered or threatened species (listed species) or result in the destruction or adverse modification of such species designated critical habitat. Section 9 prohibits the taking of a listed species. Under Section 10, the Fish and Wildlife Service and National Marine Fisheries Service may issue a permit, accompanied by an approved habitat conservation plan that allows for the incidental, non-purposeful “take” of a listed species under their jurisdiction.
National Environmental Policy Act	Requires analysis of potential environmental impacts of proposed federal actions, such as approvals for exploration and production on federal lands.
Oil Pollution Act	Spill prevention requirements, reporting obligations, and response planning (measures that will be implemented in the case of release of oil or other hazardous substances).
Resource Conservation and Recovery Act	Subtitle D concerns non-hazardous solid wastes. The Solid Waste Disposal Act exempts many wastes produced during the development of natural gas resources, including drilling fluids and produced water. EPA has determined that other federal and state regulations are more effective at protecting health and the environment.
Safe Drinking Water Act	Underground Injection Control (UIC) program preventing the injection of liquid waste into underground drinking water sources. Fluids other than diesel fuel do not require a UIC permit. The UIC program gives requirements for siting, construction, operation, closure, and financial responsibility. Forty states control their own UIC programs.

The Western Interstate Energy Board described the importance of unconventional gas reservoirs, technical aspects of hydraulic fracturing, regulation, and potential environmental impacts (McAllister, 2012). Although there are several other federal regulations that the unconventional gas industry must comply with, the SDWA is “of greatest importance to the sector” (McAllister, 2012). While state laws and regulations can vary, stringency has increased in recent years. State agencies typically oversee the well itself while local governments are generally responsible for upstream activities, such as road access to drilling sites. The potential environmental impacts include water and air quality, as well as seismic activity and noise (McAllister, 2012).

In response to concerns raised by the rapid growth in the use of fracturing, the potential impacts to groundwater and drinking water resources, and calls for increased government oversight, the Congressional Research Service (CRS) reviewed past and proposed treatment of hydraulic fracturing under the SDWA (Tiemann and Vann, 2012). The SDWA is the principal federal statute for regulating the underground injection of fluids. The Energy Policy Act of 2005 excluded hydraulic fracturing fluids and proppants (except diesel fuel) from the definition of "underground injection." Therefore, EPA has no SDWA authority to regulate hydraulic fracturing unless diesel fuel is included in the waste fluids to be injected underground.

Two federal agencies have recently taken regulatory actions related to shale gas production. EPA has applied new source performance standards and expanded mandatory greenhouse gas (GHG) reporting to include unconventional natural gas production. The BLM has proposed regulations for hydraulic fracturing on public and Indian lands.

In 2009, EPA promulgated the Mandatory Reporting of Greenhouse Gases Rule at Title 40 Code of Federal Regulations (CFR) Part 98 requiring the reporting of GHG data from large U.S. sources. This rule also requires suppliers to collect timely and accurate data to inform future policy decisions (EPA, 2009). The petroleum and natural gas industry is covered under Subpart W, and unconventional natural gas production is included under provisions for onshore production, natural gas processing, natural gas transmission, and liquefied natural gas (LNG) storage and import/export. Annual carbon dioxide (CO_2), $CH_{4,}$ and nitrogen oxide (NO_x) emissions must be reported separately for each of these segments (EPA, 2012a).

On April 17, 2012, EPA promulgated a final rule at 40 CFR Parts 60 and 63, entitled "Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews," under the Clean Air Act provisions for new source performance standards (NSPS) (EPA, 2012b). EPA expects the rule to reduce volatile organic compound (VOC) emissions by nearly 95 percent, mainly through "green" or "reduced emissions" completions that capture natural gas that currently escapes to the air. Reductions in VOC emissions will help reduce ground-level ozone in natural gas production areas and help protect against potential cancer risks from several air toxins, including benzene. Green completions also reduce CH_4 emissions. EPA estimates the combined rules will yield a cost savings of $11–19 million (MM) in 2015, because of the value of natural gas and condensate that will be recovered and sold, and the value of the climate co-benefits at $440 MM annually by 2015 (EPA, 2012b).

The BLM oversees more than 750 MM acres of federal and Indian mineral estates nation-wide, and on May 11, 2012, published a proposed rule to regulate hydraulic fracturing on public land and Indian land entitled "Oil and Gas Well Stimulation, Including Hydraulic Fracturing, on Federal and Indian Lands" at 43 CFR Part 3160. The rule would require public disclosure of the chemicals used in hydraulic fracturing on public land and Indian land, strengthen regulations related to well-bore integrity, and address issues related to flowback water (fluids used in hydraulic fracturing that are recovered from the well, which must then be disposed of) (BLM, 2012).

The BLM (2013) used comments on its proposed draft rule to make improvements and on May 24, 2013, published a supplemental notice seeking additional comments. The updated draft included provisions to ensure the protection of usable water zones through an expanded set of cement evaluation tools, including a variety of logging methods, seismograms, and other techniques. Detailed guidance on the handling of trade secret claims modeled on State of Colorado procedures was added to address concerns that industry had voiced on the disclosure of fluid constituents that were proprietary. The BLM (2013) also sought opportunities to reduce costs and increase efficiency through coordination with individual states and tribes.

States have the power to implement their own requirements and regulations for unconventional gas drilling under federal oversight. All states that produce gas have at least one agency to permit drilling wells, and many federal regulations for oil and gas production allow states to implement their own programs if these programs have been approved by the appropriate federal agencies (NETL, 2009a). While state requirements differ, any requirements set forth in federal regulations must be met at a minimum—in other words, state requirements can be more stringent than federal regulations, but they cannot be less stringent than federal regulations.

The National Energy Technology Laboratory (NETL) (2009b) and GWPC (2013) evaluated the state regulatory programs for oil and natural gas production for their applicability and adequacy for protecting water resources. NETL reviewed regulations for permitting, well construction, hydraulic fracturing, temporary abandonment, well plugging, tanks, pits, and waste handling and spills. The report presented five key messages:

1. State oil and gas regulations are adequately designed to directly protect water resources through the application of specific programmatic elements such as permitting, well construction, well plugging, and temporary abandonment requirements.
2. Experience suggests that state oil and gas regulations related to well construction are designed to be protective of groundwater resources relative to the potential effects of hydraulic fracturing. However, development of best management practices related to hydraulic fracturing would assist states and operators in insuring continued safety of the practice, especially as it relates to hydraulic fracturing of zones near groundwater, as determined by the regulatory authority.
3. Many states divide jurisdiction over certain elements of oil and gas regulation between the oil and gas agency and other state water protection agencies. This is particularly evident in the areas of waste handling and spill management.
4. The state review process conducted by the national non-profit organization STRONGER (2013) is an effective tool in assessing the capability of state programs to manage exploration and production waste and in measuring program improvement over time.

5. The implementation and advancement of electronic data management systems has enhanced regulatory capacity and focus. However, the inclusion of more environmental data is needed, as well as further work in the areas of paper-to-digital data conversion.

DOE (2011) concluded that oil and gas field activities are best regulated and managed at the state level where regional and local conditions are better understood. Effective regulatory programs use a set of tools that include formal and informal guidance, field rules, and best management practices, in addition to the regulations themselves. (DOE, 2011).

The National Conference of State Legislatures (Pless, 2012) introduces domestic natural gas production, describes legislative involvement at the state level, and summarizes the development of state legislation (Pless, 2012). Pless (2012) calls attention to public health and environmental impacts including protection of surface water, water withdrawals, air quality, habitat, and seismic activity. State policy actions fall into four categories:

1. Increasing Transparency: Disclosure of fracturing fluid chemicals and additives.
2. Generating Revenue through Taxes and Fees: Severance taxes for resources "severed" from the earth can provide significant revenue streams and impact fees can benefit local communities.
3. Water Quality Protection: Leak and spill prevention, wastewater transportation, waste treatment and disposal regulations, and well location restrictions help protect water quality.
4. Monitoring to Improve Knowledge Base: Water withdrawal and quality monitoring can protect water resources. Some states have instituted moratoria on drilling until more is known about the impacts, including New Jersey and Vermont. Other states, such as Illinois, Michigan, New York, North Carolina, Ohio, and Pennsylvania, have legislation pending various moratoria. New Jersey's moratorium was for one year, while Vermont's completely prohibits hydraulic fracturing within the state. Pending legislation would provide for impact studies and assessments, prohibit hydraulic fracturing, or establish moratoria pending the outcome of other studies.

Another analysis was completed by Resources for the Future's (RFF) Center for Energy Economics and Policy (2012) website, which looked at requirements in 31 U.S. states that either have shale gas production development or could have some soon. This review examined similar items related to shale gas development, organized into five general categories (RFF, 2012):

- Site development and preparation
- Well drilling and production
- Flowback and wastewater storage and disposal
- Well plugging and abandonment
- Well inspection and enforcement

In June 2013, RFF (2013) released a full report containing an analysis of state regulations and requirements pertaining to shale gas development, which synthesized much of the information available on the website tool into an actual document. This analysis determined that there is little similarity in the way states are regulating the various categories of shale gas development. The report did not suggest that one method was better than another, but instead identified the differences from state to state (RFF, 2013).

1.6 Federal Research and Development Programs

In 2011, the Department of Energy (DOE) delineated the technical challenges for unconventional gas development as part of the R&D program managed by NETL under the Energy Policy Act of 2005. The technical challenges for tight gas include a need for an improved understanding of the geologic environments and the environmental and safety risks, and the development of improved technologies for drilling, sensors, development, and production. For CBM, the challenges include a need for an improved understanding of the resource, water management, and improved drilling and production, including multi-seam completions. Shale gas has many of the same challenges, including improving understanding of the risks, gaining better understanding of the geologic environments, water management, and improved drilling, development, and production technologies (DOE, 2011).

DOE's shale gas program brings together federal and state agencies, industry, academia, non-governmental organizations, and national laboratories to develop oil and gas technologies under Section 999 of the Energy Policy Act of 2005. The work focuses on safety, environmental sustainability, and calculating the risks of oil and gas exploration and production undertakings. DOE has funded several technology investigations through NETL that deal with produced water management. DOE has been developing a tool that can be used to help the operators of oil and gas operations to meet challenges presented in reducing, reusing, and disposing of produced water from wells (DOE, 2013a). Fact sheets have been produced for various practices for produced water during the operation of wells, including the following (NETL, 2013):

- *Water Minimization*: Reducing the volume of produced water both entering the well and flowback at the surface
- *Water Recycling and Reus*e: Investigating alternative uses for produced water, such as underground injection, use in agricultural settings, and use in industrial settings
- *Water Treatment and Disposa*l: Discovering methods to remove impurities from the produced water and permanently dispose of the produced water

NETL is also conducting research to improve the assessment of air quality impacts in the field with a mobile air monitoring laboratory, and then using these data to model atmospheric chemistry and chemical transport to better understand local and regional impacts (DOE, 2013b). Goals of this research include the following:

- *Document Environmental Changes*: Distinguishing the changes that occur during each phase of shale gas production (e.g., site construction, drilling, well completion, early production, and production after site remediation)
- *Develop Technology and Management Practice*s: Mitigating undesired environmental changes
- *Develop Monitoring Technique*s: Increasing sensitivity and speed while decreasing costs

Projects include efforts to determine air quality, detect fugitive emissions, detect unwanted migration of production fluids, locate existing wells and pipelines, and document changes in avian populations (DOE, 2013b). Additionally, DOE is collaborating with other agencies on EPA's hydraulic fracturing study (EPA, 2012c).

EPA (2013) cooperates with key stakeholders to make sure that unconventional gas resources are managed responsibly and do not inflict unnecessary damage on the environment and on the public. In 2010, at the request of Congress, EPA initiated a study to better understand any potential impacts of hydraulic fracturing on drinking water and groundwater. The overall purpose of the study is to elucidate the relationship, if any, between hydraulic fracturing and drinking water resources, and to identify the driving factors that affect the severity and frequency of any impacts (EPA, 2011). In their plan, EPA designed their study to provide decision-makers and the public with answers to five fundamental questions associated with the hydraulic fracturing water life cycle:

- *Water Acquisition*: What are the potential impacts of large volume water withdrawals from ground and surface waters on drinking water resources?
- *Chemical Mixin*g: What are the possible impacts of surface spills on or near well pads of hydraulic fracturing fluids on drinking water resources?
- *Well Injectio*n: What are the possible impacts of the injection and fracturing process on drinking water resources?
- *Flowback and Produced Wate*r: What are the possible impacts of surface spills on or near well pads of flowback and produced water on drinking water resources?
- *Wastewater Treatment and Waste Disposa*l: What are the possible impacts of inadequate treatment of hydraulic fracturing wastewaters on drinking water resources?

In December 2012, EPA (2012c) published the first progress report for their study describing 18 research projects that are underway, including analyses of existing data, scenario evaluations, laboratory studies, toxicity assessments, and case studies.

The U.S. Geological Survey (USGS) operates both the Energy Resources Program (ERP) and the John Wesley Powell Center for Analysis and Synthesis. The ERP performs oil and gas resources assessments for the United States as well as the world, synthesizing information used to develop energy policies and resource management plans, as well as researching hydraulic fracturing and produced water (USGS, 2010; USGS, 2013a). The USGS has developed a screening process that can be used to determine whether unconventional gas resources exist in each location. The process of hydraulic fracturing and the resulting produced water and other fluids play a large role in the exploration and development of unconventional resources (USGS, 2010).

Current working groups of the Powell Center for Analysis and Strategy include one assessing the potential effect of developing shale gas resources on surface and groundwater and another investigating seismicity resulting from the injection of fluids (USGS, 2013b). The water quality investigation includes several objectives (USGS, 2012):

- *Hydraulic Fracturing*: Gain better understanding of the hydraulic fracturing process in the United States.
- *Water Quality*: Investigate surface water and groundwater quality near unconventional gas production, possible water quality changes due to production operations, and gather baseline water quality data near the production operations.
- *Data Gaps*: Determine areas where further investigation is necessary for evaluation.
- *Future Work*: Ascertain future work that can help increase understanding of how unconventional gas production affects water quality.

1.7 REFERENCES

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2 GREENHOUSE GAS EMISSIONS AND CLIMATE CHANGE

There are several major studies that detail potential GHG emissions from upstream natural gas.[b] The assumptions and parameters of these studies vary, but the majority conclude the GHG emissions from one unit of delivered unconventional natural gas are comparable to (if not lower than) the GHG emissions produced from one unit of conventional natural gas. Studies suggest, in the case of LNG, liquefaction accounts for a significant portion of total associated GHG emissions given the significant energy demand involved in the process.

To account for all sources of GHG emissions in the production of unconventional natural gas, and to evaluate their relative contributions and mitigation opportunities a systems-level perspective is both necessary and prefered. Life cycle analysis (LCA) is one type of systems approach available to account for sources of GHG emissions as LCA specifically considers the material and energy flows of a system from cradle to grave, where the cradle is the extraction of resources from the earth, and the grave is the final use and disposition of all products. NETL has used LCA to calculate the environmental impacts of natural gas production and use for electric power generation for nearly a decade. Their work has been documented in a series of reports produced between 2010 and 2019.[c] Together, these reports provide in-depth assessments of the potential GHG emissions resultant from unconventional natural gas production in the United States.

The GHG results in the NETL 2019 report encompass five stages in the natural gas supply chain, which are visualized in Exhibit 2-1 (NETL, 2019):

1. **Production**: Sources of emissions include the gas vented from pneumatically-controlled devices and fugitive emissions from flanges, connectors, open-ended lines, and valves. When vapor recovery units are feasible, vented gas is captured and flared; otherwise, vented gas is released to the atmosphere. Production operations also include the combustion of natural gas and diesel in compressors and other equipment.
2. **Gathering and Boosting**: Natural gas gathering and boosting networks receive natural gas from multiple wells and transport it to multiple facilities. Gathering and boosting sites include acid gas removal, dehydration, compressors operations, pneumatic devices, and pumps.
3. **Processing**: A natural gas processing facility removes impurities from natural gas, which improves its heating value and prepares it for pipeline transmission. Natural gas processing facilities include acid gas removal, dehydration, hydrocarbon liquids removal, and compression operations.
4. **Transmission Stations, Storage Facilities, and Transmission Pipelines**: A natural gas transmission system is a network of large pipelines that transport natural gas from processing facilities to the city gate (the point at which natural gas can be consumed by large-scale consumers or transferred to local distribution companies). Transmission

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[b] Upstream natural gas includes the construction and completion of gas wells, as well as subsequent production, processing, and transport steps.

[c] The GHG results in the NETL (2019) report supersede the GHG results in the previous NETL reports.

stations are located along natural gas transmission pipelines and use compressors to boost the pressure of the natural gas.

5. **Distribution**: Natural gas distribution networks transport natural gas from the city gate to commercial, residential, and some industrial consumers. This analysis uses the distribution portion of the supply chain only for the upstream functional unit; distribution is not necessary for the functional unit of electricity in which natural gas power plants receive natural gas directly from transmission pipelines.

Exhibit 2-1. Supply chain stages that compose the overall LCA boundary

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The flexible, consistent framework of NETL's LCA model allows different natural gas sources to be compared on a common basis. In the NETL 2019 report, five types of extraction technologies are considered:

1. **Conventional natural gas** is extracted via vertical wells in high permeability formations that do not require stimulation technologies for primary production.
2. **Coalbed methane** is extracted from coal seams and requires the removal of naturally occurring water from the seam before natural gas wells are productive.
3. **Shale gas** is extracted from low permeability formations and requires hydraulic fracturing and horizontal drilling.
4. **Tight gas** is extracted from non-shale, low permeability formations and requires hydraulic fracturing and directional drilling.
5. **Associated gas** is found with petroleum (either dissolved in oil or in a gas cap in a petroleum formation) and is produced by oil wells.

Exhibit 2-2 shows the 2016 production share for the 30 onshore, offshore, and associated natural gas scenarios (NETL, 2019). These production shares are based on filtered Drillinginfo Desktop production data. Exhibit 2-3 extrapolates the production shares of 14 onshore regions to represent all onshore production (which is 79.6 percent of total U.S. production) (NETL, 2019). The remaining balance of U.S. production comes from offshore natural gas wells (4.3 percent) and associated gas (16.1 percent).

Exhibit 2-2. Natural gas production shares by well type and geography

Geography	Well Type						
	Conventional	Shale	Tight	CBM	Offshore	Associated	Total
Onshore Production							
Anadarko	2.2%	2.6%	1.7%				6.5%
Appalachian		29.0%					29.0%
Arkla	0.4%	4.7%	1.4%				6.6%
Arkoma	0.3%	0.9%					1.2%
East Texas	1.6%	1.2%	1.3%				4.2%
Fort Worth Syncline		1.8%	0.0%				1.8%
Green River	1.6%		3.9%				5.5%
Gulf Coast	0.8%	6.6%	1.3%				8.7%
Permian	2.3%	5.3%					7.6%
Piceance			0.3%				0.3%
San Juan	1.4%			1.9%			3.3%
South Oklahoma		1.0%					1.0%
Strawn		3.2%					3.2%
Uinta	0.5%		0.8%				1.3%
*Subtotal Onshore**	*11.0%*	*58.0%*	*10.6%*	*1.9%*			*79.0%*
Offshore Production							
Offshore Gulf of					4.2%		4.2%
Offshore Alaska					0.1%		0.1%
Subtotal Offshore					*4.3%*		*4.3%*
Associated Gas							
United States						15.1%	16.1%
Total							
*Total**	*11.0%*	*58.0%*	*10.6%*	*1.9%*	*4.3%*	*15.1%*	*100%*

* Due to rounding errors, the subtotals for onshore wells and the totals for all well types do not exactly match the sums of values reported for individual well types.

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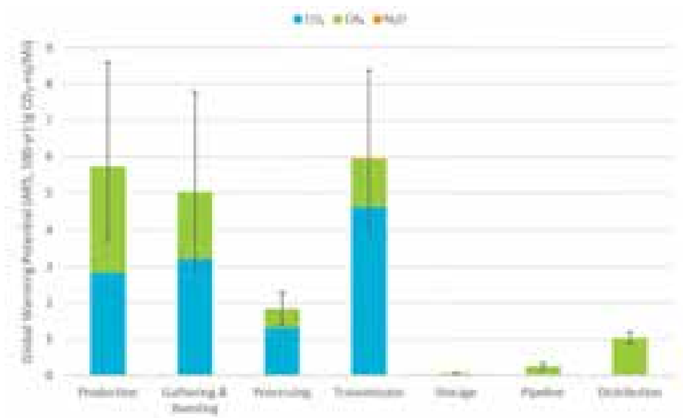
2.1 A Life Cycle Perspective

Exhibit 2-3 shows the upstream GHG emissions from the different parts of the supply chain. The blue bars represent carbon dioxide (CO_2) emissions, the green bars represent methane (CH_4) emissions, and the orange bars represent nitrous oxide (N_2O) emissions. The vertical black lines in Exhibit 2-3 represent the error bars in this analysis. These emissions are expressed in terms of 100-year global warming potential (GWP) as recommended by the Intergovernmental Panel on Climate Change (IPCC) (2023). GWPs normalize GHG species to a common basis. For example, the 2013 version of IPCC's GWPs show that the radiative forcing of CH_4 is 28 times greater than CO_2 over a 100-year period; to arrive at a common basis, the life cycle results for CH_4 are multiplied by 28 so CO_2 and CH_4 can be expressed in common units—carbon dioxide equivalents (CO_2e).

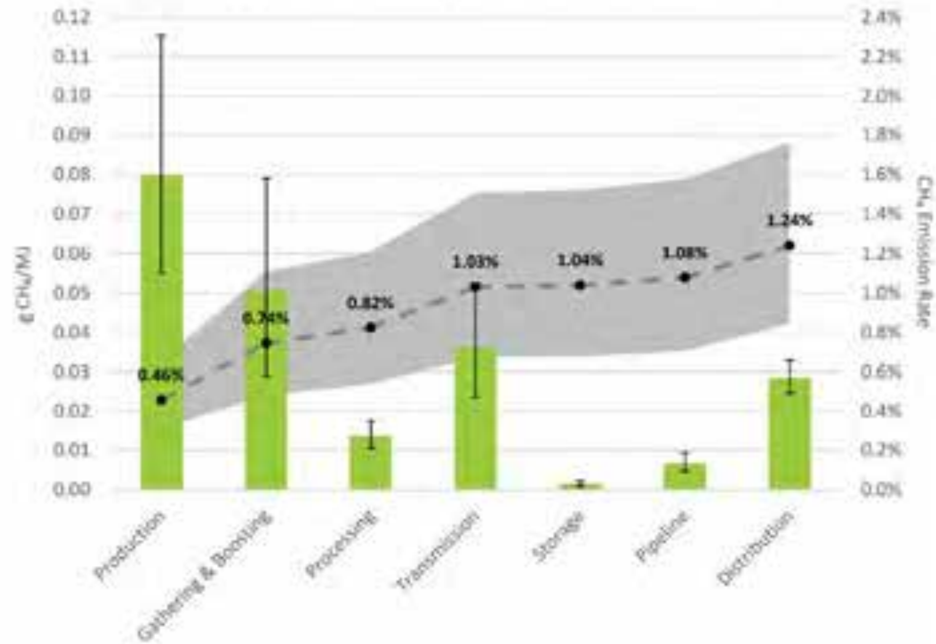
Exhibit 2-3. Life cycle GHG emissions for the U.S. natural gas supply chain



In addition to its characterization of domestic upstream natural gas, NETL also developed life cycle data for exported LNG, including the GHG emissions from liquefaction, transport, regasification, and combustion for electricity generation (NETL, 2019). The burdens of liquefaction, ocean transport, and regasification significantly increase the upstream burdens of LNG relative to natural gas that is not liquefied.

The life cycle GHG emissions from the U.S. natural gas supply chain are 19.9 grams (g) CO_2e/megajoule (MJ) (with a 95 percent mean confidence interval of 13.1–28.7 g CO_2e/MJ) (NETL, 2019). The top contributors to CO_2 and CH_4 emissions are combustion exhaust and other venting from compressor systems. Compressor systems are prevalent in most supply chain stages, so compressor emissions are key emission drivers for life cycle emissions. Exhibit 2-4 shows life cycle GHG emissions from different sectors of the U.S. natural gas supply chain (NETL, 2019). Emission rates are highly variable across the entire supply chain. The national average CH_4 emission rate is 1.24 percent, with a 95 percent confidence interval ranging 0.84–1.76.

Exhibit 2-4. Life cycle CH_4 emissions from the U.S. natural gas supply chain



2.2 Key Contributors to Natural Gas GHG Emissions

The key drivers of GHG results for the entire natural gas value chain are illustrated in Exhibit 2-5 (NETL, 2019). These boundaries are also referred to as "cradle-to-gate," where the cradle is the extraction of natural gas from nature and the gate is the delivery of natural gas to a power plant via a natural gas transmission pipeline. These results use the same boundaries as Exhibit 2-1, but show more detail on the contribution of specific unit processes in the supply chain.

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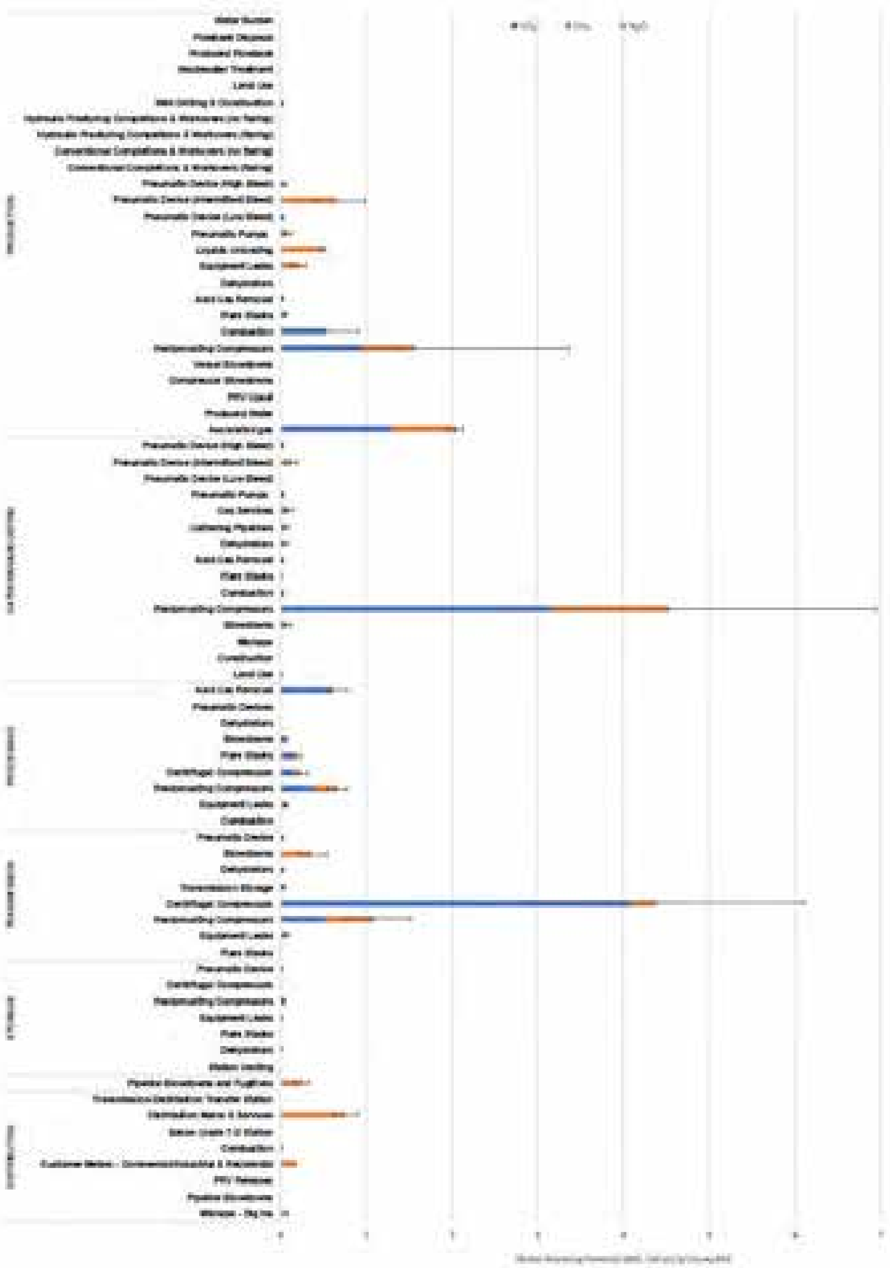
Exhibit 2-5. Detailed GHG emission sources for the U.S. natural gas supply chain

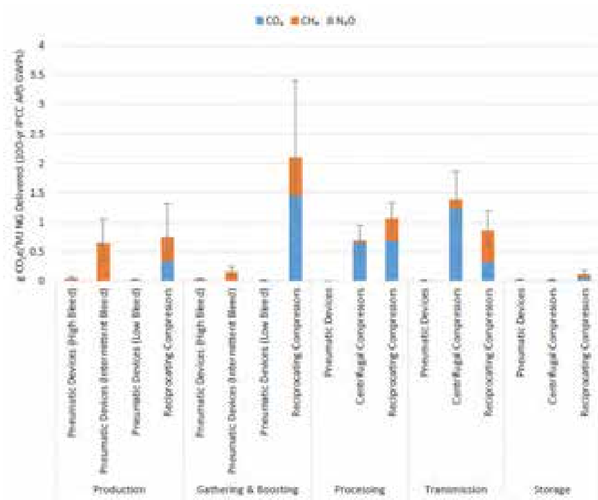


Pneumatic devices and compression systems are two emission's sources representing a significant portion of the life cycle natural gas GHG emissions of the natural gas supply chain (NETL, 2019). Pneumatic devices are used to operate level controllers, valves, and other equipment at natural gas facilities. According to the EPA's Greenhouse Gas Inventory, production pneumatics emitted 1,060 kilotons of CH_4 in 2017, accounting for 16 percent of the total CH_4 emissions from the natural gas supply chain. Pneumatic device activity is concentrated at production facilities and there were 833,000 pneumatic devices used by U.S. production facilities in 2019 (NETL, 2019). The above results show that pneumatic devices are a key contributor to GHG emissions for both conventional and unconventional technologies.

Natural gas is compressed for transport from the processing facility to the consumer, so upstream GHG emissions are sensitive to pipeline distance and the number of compressors that the natural gas must pass through. The energy intensity of compression and the fugitive CH_4 emissions from compressors both contribute to upstream emissions (NETL, 2019). In addition to being a source of CH_4 emissions, compressors are also a source of CO_2 emissions. Most compressors in the U.S. pipeline transmission network are powered by natural gas that is withdrawn from the pipeline itself. Electric motors are not widely used by natural gas pipelines but are installed where local emission regulations limit the use of internal combustion engines or where inexpensive electricity is available (Hedman, 2008). Approximately three percent of compressors used by the natural gas transmission network are electrically driven.

Compression systems have two sources of CH_4 emissions: CH_4 that slips through combustion exhaust and CH_4 that escapes through compressor seals or packing. Natural gas systems use centrifugal and reciprocating compressors. Centrifugal compressors are more appropriate for pressure boosting applications in a steady-state application (such as a transmission pipelines), and reciprocating compressors are more appropriate when gas flow is variable and when large increases in pressure are required. Centrifugal compressors are typically driven by gas-fired turbines but, in some instances, are driven by an electric motor; reciprocating compressors are driven by gas-fueled engines. Exhibit 2-6 illustrates the emissions associated with pneumatic devices and compressors.

Exhibit 2-6. GHG emissions from pneumatic devices and compressors across the NG supply chain

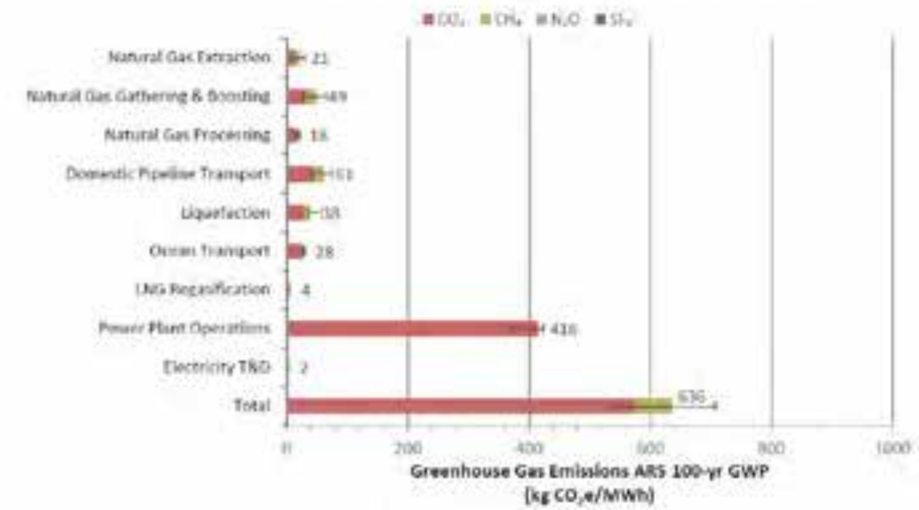


For all natural gas production types, the GHG results are sensitive to production rates and episodic emissions (either liquid unloading or workovers). For the delivery of 1,000 kilograms (kg) of natural gas to a power plant, 12.5 kg of CH_4 are released to the atmosphere, 30.3 kg are flared to CO_2 via environmental control equipment, and 45.6 kg are combusted in process equipment. When these mass flows are converted to a percent basis, CH_4 emissions to air represent a 1.1 percent loss of natural gas extracted, CH_4 flaring represents a 2.8 percent loss of natural gas extracted, and CH_4 combustion in equipment represents a 4.2 percent loss of natural gas extracted. These percentages are based on *extracted* natural gas. Converting to a denominator of *delivered* natural gas gives a CH_4 leakage rate of 1.2 percent (NETL, 2019).

The factors for episodic emissions are based on the supporting documentation for EPA's national GHG inventory. EPA's emission factor for unconventional well completions and workovers are 9,000 thousand cubic feet (Mcf) of natural gas emissions per episode, which was developed from a series of presentations by their Natural Gas Science to Achieve Results (STAR) program. The data behind this emission factor are highly variable, ranging from 6,000 to over 20,000 Mcf per episode (6–20 million cubic feet [MMcf] per episode), and include data collected in the 1990s (EPA, 2010; Cathles, 2012). It should also be noted that this emission (9,000 Mcf/episode) and other emissions from unconventional extraction operations can be captured and flared using current technologies (Cathles, 2012). An increase in flaring rate will significantly reduce the GHG emissions from unconventional natural gas production.

An NETL (2019) report that analyzed the lifecycle emissions of exporting U.S. LNG to Europe yielded the following emissions output (assuming end-use in electricity generation) found in Exhibit 2-7.

Exhibit 2-7. GHG emissions from exporting LNG from the United States to Europe



2.3 Other Natural Gas Analyses

Several other research teams have performed system-level LCAs of natural gas production using methodologies similar to those used and documented by NETL. The results of three non-NETL studies are generally consistent with NETL's planned analysis approach and indicate that the GHG emissions from unconventional production are comparable to, if not lower than, emissions conventional production. The widely cited exception is a study by Howarth et al. (2011) that shows higher emissions for unconventional gas relative to conventional natural gas and higher emissions for both relative to the other studies.

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Jiang et al. (2011) estimated the GHG emissions from Marcellus Shale natural gas and compared them to U.S. domestic average natural gas. They concluded that development and completion of a Marcellus Shale natural gas well has GHG emissions that are 11 percent higher than the development and completion of an average conventional natural gas well. This 11 percent difference is based on a narrow boundary, representing only the differences in well development and completion for Marcellus Shale and conventional natural gas. When the life cycle boundaries are expanded to include combustion to generate electricity, the percentage difference between the GHG emissions from Marcellus Shale and conventional natural gas is reduced to 3 percent. In other words, as the boundaries of the systems are expanded, the differences in emissions between conventional and unconventional wells are overshadowed by other processes in the natural gas supply chain (Jiang et al., 2011).

Burnham et al. (2011) and Clark et al. (2011) estimated the GHG emissions from shale gas and compared it to conventional natural gas and other fossil energy sources. Their results show that shale gas emissions are 6 percent lower than those from conventional natural gas, but the overlapping uncertainty of the results prevents definitive conclusions about whether shale gas has lower GHG emissions than conventional gas.

Weber and Clavin (2012) applied Monte Carlo uncertainty analysis to a set of six natural gas LCAs being performed and concluded that the upstream GHG emissions from conventional and shale gas are similar. The six studies include four of the studies mentioned herein (Burnham et al., 2011; Howarth, 2011; Jiang et al., 2011; NETL, 2012), and two additional studies conducted at University of Maryland (Hultman et al., 2011) and Shell Global Solutions (Stephenson et al., 2011).[e] Weber and Clavin (2012) recommend the use of efficient technologies for converting natural gas to electricity, heat, or transportation applications. They also recommend implementation of reduced emission completions (RECs) for the development of shale gas wells.

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Research conducted by Howarth et al. (2011) concludes that the high volumes of gas released by hydraulic fracturing make the life cycle GHG footprint of shale gas significantly higher than conventional gas. According to Howarth's analysis, 3.6 to 7.9 percent of the natural gas extracted from shale gas wells is released to the atmosphere as CH_4.

It is important to note that the boundaries of these LCAs discussed here are not identical. For example, Jiang et al. (2011) and Weber and Clavin (2012) use the same boundaries as NETL (2019), but Argonne National Laboratory's analysis includes scenarios for vehicles that use compressed natural gas (Burnham et al., 2011) and Howarth's (2011) analysis includes distribution of natural gas beyond the natural gas transmission network to include small-scale end users. Fortunately, the transparency of these analyses allows boundary reconciliation, so the World Resources Institute (WRI) converted them to an upstream basis (from natural gas extraction through natural gas delivery via pipeline) (Bradbury et al., 2013). ***Exhibit 2-8*** shows the GHG results as compiled by WRI's study (Bradbury et al., 2013). These results use a 100-year time scale to show GHG emissions in terms of CO_2e/MJ of delivered natural gas. While WRI shows these results based on similar boundaries, each author used a different basis for calculating uncertainty. The error bars shown in ***Exhibit 2-8*** are a mix of data, parameter, and scenario uncertainties.

WRI also reconciled NETL's upstream natural gas results, shown in ***Exhibit 2-8***. However, WRI's reconciliation is representative of NETL's 2012 natural gas analysis. NETL's current results, representative of modeling updates made in 2012 and 2013, have expected values that are lower than other authors.

[e] The analysis by the University of Maryland (Hultman et al., 2011) concludes that unconventional natural gas has upstream GHG emissions that are approximately 2 percent higher than those from conventional natural gas; the analysis by Shell Global Solutions (Stephenson et al., 2011) concludes that unconventional gas has upstream GHG emissions that are 11 percent higher than those from conventional natural gas. These two analyses do not contradict nor expand upon the conclusions of the other upstream natural gas analyses discussed in this report, so they are not discussed further.

Exhibit 2-8. Upstream GHG comparison between conventional and unconventional natural gas

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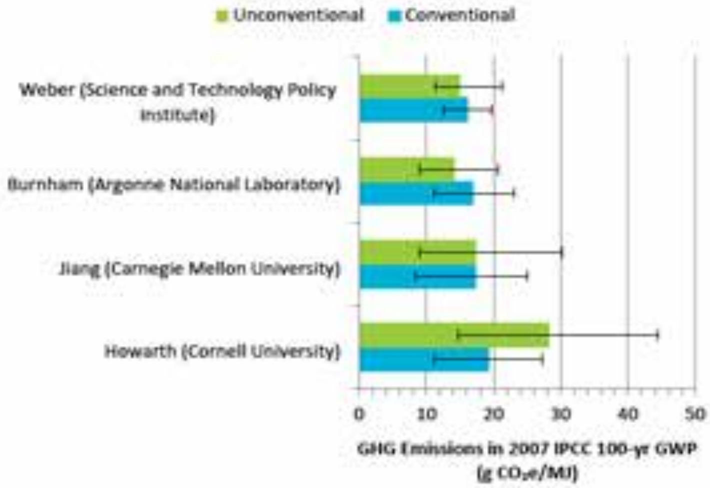

The studies shown in Exhibit 2-9 identify extraction, processing, and transport as sources of CH_4 leakage, but, other than well completion emissions, do not specify the sub-activities that contribute to CH_4 leakage. As identified by NETL's model, the top four contributors to CH_4 leakage from unconventional natural gas are completions, workovers, pneumatically-controlled valves used at extraction, and compressors used during processing and pipeline operations (NETL, 2014).

Exhibit 2-9. Comparison of leakage rates from upstream natural gas

Author	CH_4 Leakage Rate	
	Conventional Onshore	Unconventional
Weber (Science and Technology Policy Institute)	2.80%	2.42%
Burnham (Argonne National Laboratory)	2.75%	2.01%
Howarth (Cornell University)	3.85%	5.75%

Because of the potency of CH_4 as a GHG, CH_4 leakage rates dominate the GHG emissions from upstream natural gas systems. Exhibit 2-9 compares the CH_4 leakage rates for conventional and unconventional natural gas extraction, as calculated by three analyses. As discussed earlier, NETL's leakage rate for the 2010 supply mix of all domestic natural gas sources is 1.2 percent and is expressed in terms of CH_4 emissions per unit of natural gas delivered to a large-scale consumer. Jiang does not explicitly report a CH_4 leakage rate. The boundaries on these leakage rates are from extraction through delivery (Bradbury et al., 2013).

The differences in GHG emissions and CH_4 leakage rates among natural gas analyses are driven by different data sources, assumptions, and scopes (Bradbury et al., 2013). Other differences among these analyses, as identified in literature, are summarized below.

Most analysts use IPCC GWPs to scale CH_4 to an equivalent quantity of CO_2. Howarth does not use IPCC GWPs, but uses GWPs developed by Shindell, a National Aeronautics and Space Administration scientist whose calculations account for the heating and cooling effects of aerosols in addition to GHGs (Howarth et al., 2011). On a 100-year time frame, the IPCC and Shindell GWPs for CH_4 are 25 and 33, respectively (Bradbury et al., 2013; Howarth et al., 2011; MIT, 2011). Howarth uses a CH_4 GWP that is 32 percent higher than used by others, but further analysis and reconciliation is necessary to determine how much Howarth's unique GWP contributes to the difference between Howarth's and others' GHG results; the choice of GWP factors is one of several modeling and data choices unique to Howarth's analysis. Howarth (2012) acknowledges the uncertainty in GWPs and defends his use of Shindell GWPs on the basis that they are representative of the most recent science.

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GWPs will change as scientific understanding of climate change progresses. The IPCC recently finalized its Fifth Assessment Report (AR5) on climate change, which includes GWPs that will supplant the GWPs from the fourth assessment report (released in 2007). AR5 increases the 100-year GWP of CH_4 from 25 to 28. Further, if the global warming caused by the decay of CH_4 to CO_2 is to be included within the boundaries of an analysis, AR5 recommends a 100-year GWP of 30 for CH_4. The GWP of CH_4 is a function of the radiative forcing directly caused by CH_4 in the atmosphere, as well as the radiative forcing from products of CH_4 decay. IPCC increased the GWP of CH_4 based on new data that shows that the lifetime of CH_4 in the atmosphere is 12.4 years (a 12-year lifetime was used in the previous version). IPCC also increased the GWP of CH_4 based on revised assumptions about relationships among CH_4, ozone, and water vapor in the atmosphere (Stocker et al., 2013).

There is uncertainty as to how much CH_4 is released during the initial flowback of water from an unconventional well. The emission of natural gas from flowback water accounts for most of the emissions from the completion of shale gas wells. EPA's emission factor for natural gas released from the flowback from unconventional completions is approximately 9,000 Mcf per episode. The data behind EPA's emission factor are highly variable, ranging 6,000–20,000 Mcf/episode, and include data collected in the 1990s (EPA, 2010). NETL (2014) uses EPA's emission factor for flowback emissions. Carnegie Mellon University's analysis of upstream natural gas assumes that flow back CH_4 emissions are equal to the total gas produced during the first 30 days of production (4,100 Mcf per episode) (Jiang et al., 2011). Howarth (2011) averages the flowback emissions from two shale gas wells and two tight gas wells and concludes that flowback emissions are 1.6 percent of the total gas produced by a well during its entire life. Howarth does not explicitly state a flowback emission factor in terms of Mcf/episode but applying Howarth's 1.6 percent loss factor to the four wells cited in Howarth's analysis translates to flowback emissions of 47,000 Mcf/episode. Another data point is an emission factor of 5,000 Mcf/episode, which was developed by Southern Methodist University for the Environmental Defense Fund (EDF) and is representative of shale gas development in the Barnett Shale (Armendariz, 2009). The flowback emissions used by other authors discussed in this report are not clearly stated in their work.

Howarth (2012) does not use EPA's emission factor to characterize flowback emissions but rather compiles data from five basins where unconventional extraction is occurring (Barnett, Piceance, Uinta, Denver-Jules, and Haynesville) and assumes a 10-day period in the last stages of flowback during which gases "freely flow." The data that Howarth (2012) uses to characterize the Haynesville basin is especially high, ranging 14–38 MMcf/day. Other analysts claim that the flowback fluid does not contain as much gas as indicated by Howarth's data. During flowback, non-gaseous material obstructs the wellbore and prevents the release of CH_4 and other gases (Bradbury et al., 2013; Cathles, 2012; O'Sullivan and Paltsev, 2012).

Commented [HSAJ42]: Production data? Flowback data? Be specific.

Estimated ultimate recovery (EUR) is used to apportion the one-time impact of flowback emissions per unit of natural gas produced (Howarth, 2012; Hughes, 2011; NETL, 2014). NETL (2014) uses EURs of 3.0 and 3.25 billion cubic feet (Bcf) for Barnett Shale and Marcellus Shale, respectively, based on 2009 production data for the Barnett play (levelized over 30 years of production), and a decline curve analysis[e] of initial production rates reported by producers in the Marcellus play. Jiang et al. (2011) use an EUR of 2.7 Bcf over a 25-year period and note that some producers have EURs as high as 7.3 Bcf. Howarth (2012) points to the uncertainty in lifetime production rates for unconventional wells and contends that the EURs used by NETL and Jiang are too high. To represent the EUR of all unconventional wells, Howarth uses a value of 1.24 Bcf, which is based on a decline curve analysis of Barnett Shale wells (Hughes, 2011). The variability in EURs for shale gas wells is due to a lack of long-term historical production data. Shale gas wells use new technologies to extract natural gas from previously unproductive geological formations; EURs are merely estimates of long-term performance using initial production data and assumptions about long-term performance (NETL, 2014). As shale gas extraction develops, the uncertainty in EURs will be reduced.

Flaring is the controlled combustion of natural gas that cannot be easily captured and sold. Unconventional gas is sometimes flared during well completion. Flaring is an important safety practice, and it also reduces the GWP of natural gas extraction and processing operations by converting CH_4 to CO_2. Again, zero venting is the ultimate goal, but if venting happens, then it is environmentally preferable to flare vented gas because flaring reduces the GWP of the vented gas (NETL, 2019). Analysis performed by NETL (2019) and O'Sullivan and Paltsev (2012) assumed a 15 percent flaring rate.

Most natural gas analyses use EPA's national GHG inventory to calculate natural gas pipeline emissions. The national inventory data accounts for the different fates of CH_4 (fugitive emissions, venting from compressors, and combustion in compressors) during natural gas transport (Bradbury et al., 2013; NETL, 2014). Howarth does not use guidance from the national GHG inventory to account for the sources of CH_4 emissions during natural gas transmission (Howarth et al., 2011; Cathles et al., 2011). Howarth assumes that the difference in CH_4 between the inlet and outlet of the pipeline is equal to CH_4 emissions from pipeline operation. This mass balance approach does not account for the consumption of CH_4 by pipeline compressors (Cathles et al., 2011). Pipeline compressors combust CH_4 for compression energy,

[e] The production rate of a well declines as the well gets older. A decline curve analysis plots the production rate of a well over time; the area under the curve represents the total lifetime production of the well. By knowing the initial production rate of a well and then assuming a shape for the production curve, the total lifetime production of the well can be estimated.

converting CH_4 to CO_2 in the process (NETL, 2014). Howarth (2012) acknowledges the limitation of his approach, but also points out that EPA inventory data are more than ten years old and rely too heavily on voluntary industry reporting (Bradbury et al., 2013).

Howarth includes two phases of natural gas transport: transmission and distribution (Howarth et al., 2011; Cathles et al., 2011). Transmission moves natural gas from a processing plant to large-scale consumers near cities or export terminals; distribution is an additional step that moves natural gas to commercial or residential consumers (EIA, 2008). Howarth (2012) points out that heat generation, which includes a large share of small residential and commercial consumers and requires a natural gas distribution network, accounts for the largest share of natural gas consumption in the United States. Other natural gas analyses focus on the use of natural gas for power generation, which does not require natural gas distribution (NETL, 2019; Bradbury et al., 2013).

Collaboration between the University of Texas and EDF is a recent example of how data collected at natural gas extraction sites can inform natural gas analysis. Emissions were measured at 489 natural gas wells across the United States and include conventional and unconventional extraction technologies. Based on these measurements, the University of Texas calculated that the total CH_4 emissions from natural gas extraction represent a 0.42 percent loss of CH_4 at the extraction site; this loss factor is an aggregate of conventional and unconventional wells and represents only the natural gas production activities at the extraction site, not processing or pipeline transmission. The measurements also include emissions from 27 unconventional completions and show that environmental control equipment can reduce the CH_4 emissions from unconventional completion to levels that are 97 percent lower than the completion emissions currently estimated by EPA. The University of Texas and EDF have published only one paper about their research to this point, although additional papers are expected (Allen et al., 2013).

A survey conducted by the American Petroleum Institute (API) and America's Natural Gas Alliance (ANGA) is an example of how data collected by industry can inform the emission factors used by analysts. These organizations surveyed 20 member companies to collect data from 91,000 domestic natural gas wells. Based on the survey, API and ANGA conclude that the rate of workovers for unconventional wells (also known as "refracture frequency") is one-tenth of the rate specified by EPA's documentation of the oil and gas sector (Shires et al., 2012).

Brandt et al. (2014) reviewed 20 years of technical literature on natural gas emissions in North America and demonstrated that the CH_4 emission factors used by different authors are highly variable. One source of variability is the way in which CH_4 emissions data are collected; some emissions are measured at a device level (e.g., the flowback stream from a hydraulic fracturing job), while other emissions are measured at regional boundaries (e.g., atmospheric sampling in a region that has natural gas production). Theoretically, if these two types of measurements are scaled correctly, they should result in similar CH_4 emission factors; however, the two methods lead to GHG results that differ by a factor of ten. Brandt et al. (2014) conclude that improved science for determining CH_4 leakage will lead to cost-effective policy decisions.

Improper well construction and fractures in rock formations can also result in CH_4 emissions from the target formation during production. The current life cycle models for shale gas extraction do not include groundwater as a source of GHG emissions. CH_4 migration as a potential source of drinking water contamination is discussed in greater detail in Chapter 4 – Water Use and Quality.

Littlefield et al. (2022) show that geography matters in terms of GHG emissions from the natural gas supply chain. Where gas is produced and ultimately used plays a tremendous role in total GHG emissions, so much that a national average value is not adequate. Their work provides a detailed life cycle perspective on GHG emissions variability owing to where natural gas is produced and where it is delivered. They disaggregated transmission and distribution infrastructure into six regions, balanced natural gas supply and demand locations to infer the likely pathways between production and delivery and incorporated new data on distribution meters. The average transmission distance for U.S. natural gas is 815 kilometers (km) but ranges 45–3,000 km across estimated production-to-delivery pairings. In terms of total GHG emissions, the delivery of 1 MJ of natural gas to the Pacific region has the highest mean life cycle GHG emissions (13.0 g CO_2e/MJ) and the delivery of natural gas to the Northeast United States has the lowest mean life cycle GHG emissions (8.1 g CO_2e/MJ).

MacKinnon et al. (2018) demonstrate that natural gas generation and the natural gas system could play several important roles in supporting sustainable energy strategies over time that can achieve societal GHG reduction goals and help the transition to renewable sources. Natural gas generation can support transitions to renewable resources 1) by use in advanced conversion devices to provide complementary grid services efficiently and with very low emissions to maximize the benefits of intermittent renewable resources, and 2) natural gas generation and the existing natural gas system can support the use of renewable gaseous fuels with high energy and environmental benefits. In 2020, NETL collaborated with industry and published an analysis of Our Nation's Energy Future's (ONE Future) portfolio of assets (Rai et al., 2020). ONE Future is a natural gas industry partnership dedicated to improving the efficiency of the natural gas supply chain. ONE Future represents 1–13 percent of total throughput in the respective segments of the natural gas industry value chain. The expected life cycle CH_4 emission rate for ONE Future average natural gas is 0.76 percent (with a 95 percent confidence interval ranging of 0.49–1.08 percent). The expected life cycle CH_4 emission rate for the U.S. average scenario is 1.06 percent. In terms of IPCC 100-year GWP, the ONE Future and U.S. average scenarios emit 9.7 and 14.1 g CO_2e/MJ of delivered natural gas, respectively.

Balcombe et al. (2016) document the wide range of CH_4 emissions estimates across the natural gas supply chain. Estimates of combined CH_4 and CO_2 emissions ranged from 2–42 g CO_2e/MJ.

2.4 MITIGATION MEASURES

The NSPS regulates emissions from the oil and gas sector. The new regulations are applicable to new or modified wells. The final NSPS rule that was established in August 2012 focuses on RECs, compressor seals, storage tanks, and pneumatic controllers. RECs use portable equipment that is brought onsite to capture gas from the solids and liquids generated during the flowback of hydraulic fracturing water. RECs equipment includes plug catchers and sand traps that remove drilling cuttings and finer solids that result from well development. Three phase separators are used to separate gas and liquid hydrocarbons from flowback water. These separation processes are necessary only during completions and workovers to prevent the release of CH_4 and other gases to the atmosphere and to reduce the need for flaring (EPA, 2011a).

Compressor seals include the wet seals used by centrifugal compressor and the rod packing used by reciprocating compressors. Wet seals surround the rotating shaft of a centrifugal compressor with oil, which prevents gas leakage from the compressors. The oil used by wet seals must be continuously regenerated, which releases CH_4 to the atmosphere. By replacing wet seals with mechanical dry seals, the CH_4 emissions from centrifugal compressors can be reduced (EPA, 2011b). Reciprocating compressors prevent CH_4 leakage by encasing each compressor rod with a set of oil-coated, flexible rings. Proper maintenance and routine replacement of these rings prevents unnecessary leakage of CH_4 (EPA, 2006c). Storage tanks hold flowback water and liquid hydrocarbons recovered from the production stream. Variable loading levels and temperatures cause the venting of CH_4 and other gases from these tanks. By installing vapor recovery units on storage tanks, producers can reduce emissions from natural gas production (EPA, 2006b). The captured emissions can be combusted onsite to provide process energy, or they can be channeled to the sales stream. Pneumatic controllers use gas pressure to open and close valves throughout a natural gas production and processing system. Natural gas is commonly used to pressurize pneumatic control systems. The bleeding of natural gas from pneumatic controllers vents CH_4 to the atmosphere. The GHG impact of pneumatic control systems can be reduced by installing pneumatic systems that use pressurized air instead of pressurized natural gas (EPA, 2006a). Since the regulations focus on RECs, they are more applicable to unconventional wells. However, the regulations also mandate emission reductions from pneumatically-controlled valves and compressor seals, which are two types of emission sources common to conventional and unconventional technologies.

The 2012 NSPS regulations do not cover emissions from liquid unloading or natural gas pipeline transmission. Participants in the Natural Gas STAR program have demonstrated that automated plunger lift systems can remove liquids from the wellbore at optimal frequencies that prevent the venting of natural gas to the atmosphere. Other technologies for reducing emissions from liquids unloading include the use of smaller diameter tubing that maintains production pressures at levels that reduce the frequency of liquid unloading, and foaming agents that reduce the density and surface tension of accumulated liquid (EPA, 2011c). The replacement of wet seals and rod packing on transmission pipeline compressors and applying the same type of improvements that can be applied to compressors at extraction and processing sites, can further reduce pipeline emissions and product losses. The goal of NSPS is to reduce CH_4 emissions from the targeted sources (completions, compressors, pneumatic valves, and storage tanks) by 95 percent.

An NETL report (Littlefield et al., unpublished) notes that compressed-air pneumatics are a mature technology that reduces CH_4 emissions from pneumatic systems. The technology replaces existing devices, which are actuated by natural gas, with devices that are actuated with compressed air. This requires the addition of electric-powered air compressors at natural gas facilities but can result in zero CH_4 emissions from pneumatics. A barrier to implementation of compressed-air pneumatics is electricity availability. The United States has an extensive electricity grid, but grid connections are not always near production sites. The same report

NETL (Littlefield et al., unpublished) notes that proven technologies exist for reducing CH_4 emissions from compression systems:

- Centrifugal compressors emissions can be reduced by replacing wet seals with dry seals. These seals are used around the rotating shaft of the compressor and prevent high pressure gas from escaping the compressor. Wet seals involve the use of recirculating oil that emits 40–200 standard cubic feet (scf) of natural gas per minute (min). Dry seals use gas to seal the compressor shaft and emit only 6 scf/min (EPA, 2006a). The replacement of wet seals with dry seals reduces centrifugal compressor emissions by 85–97 percent.
- Reciprocating compressor emissions can be reduced by replacement of rod packing. Packing prevents gas from moving around piston rods and escaping the compression cylinder. New packing that is properly installed on a well-maintained compressor will emit about 12 scf/hour. The emission rate for old or poorly installed packing can range 25–67 scf/hour (EPA, 2006a). When compared to emission rate for new packing, this equates to potential emission reductions of 52–82 percent. Rod packing replacement is a mature technology, but there are new technologies that can also reduce reciprocating engine exhaust slip. These new technologies include advanced materials that increase piston rod service life while reducing rod wear and Teflon-coated rings that reduce friction while maintaining a tight seal. There are no data on the emission reduction potentials of these new technologies.
- The majority of the CH_4 emissions from reciprocating compressors are due to the CH_4 slip from engine exhaust. Comparing the exhaust emission factors for rich burn and lean burn engines shows that lean burn engines have a combustion effectiveness of 97 percent and lean burn engines have combustion effectiveness of 99 percent. Air-fuel-ratio controls are an option for improving the combustion effectiveness of lean burn engines while keeping NO_x emissions low. More research is required to understand the limits of air-fuel-ratio controls but, for this analysis, it is assumed that they can increase the combustion effectiveness of a lean burn engine by 97-99 percent (EPA, 2006a).

Exhibit 2-10. Quantification of mitigation measure impact for pneumatic devices and compressors

Strata	Stage	Pneumatic Devices	Compressor (centrifugal)	Compressor (reciprocating)	Exhaust (turbine)	Exhaust (engine)
Before Mitigation	Production	1.02E+06	N/A	4.90E+03	N/A	1.48E+05
	Gathering and Boosting	N/A	1.34E+04	2.34E+03	4.41E+02	3.95E+05
	Processing	N/A	2.01E+04	4.40E+04	9.90E+02	1.35E+05
	Transmission and Storage	N/A	1.54E+04	6.26E+04	1.34E+03	8.71E+04
After Mitigation	Production	5.10E+05	0.00E+00	3.55E+03	N/A	8.38E+04
	Gathering and Boosting	N/A	2.73E+04	2.32E+04	4.41E+02	2.17E+05
	Processing	N/A	8.26E+03	3.17E+04	9.90E+02	8.12E+04
	Transmission and Storage	N/A	1.42E+04	4.24E+04	1.34E+03	5.21E+04

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With respect to liquefaction, Mokhatab et al. (2014) notes that most of the plant energy consumption and resultant emissions in natural gas liquefaction facilities occurs in the compressor drivers where fuel energy (usually natural gas) is converted to mechanical work (or electricity in case of electrically driven compressors). Due to the energy consumption scale of the LNG plants, any enhancement to the energy efficiency of LNG plants will result in a significant reduction in gas consumption and consequently CO_2 emission (Mokhatab et al., 2014). There are two ways to increase the energy efficiency of natural gas liquefaction cycles: liquefaction cycle enhancement and driver cycle enhancement. Liquefaction cycle enhancements reduce the compressor power and consequently the compressor driver's fuel consumption. Driver cycle enhancement reduces the amount of fuel consumption to generate a specific amount of power. Typical natural gas liquefaction cycles utilize either pure refrigerant in cascade cycles, expansion-based cycles, or mixed refrigerant cycles. Pure refrigerant cycles have a constant evaporating temperature that is a function of the saturation pressure. Mixed refrigerant cycles, on the other hand, do not maintain a constant evaporating temperature at a given pressure. Their evaporating temperature range, called temperature glide, is a function of their pressure and composition. A refrigerant mixture of hydrocarbons and nitrogen (N_2) is chosen so that it has an evaporation curve that matches the cooling curve of the natural gas with the minimum temperature difference. Small temperature difference reduces entropy generation and, thus, improves thermodynamic efficiency, reduces power consumption, and reduces emissions associated with liquefaction facilities (Mokhatab et al., 2014).

A study from Pospíšil et al. (2019) notes that a certain part of the energy spent on liquefaction can be recovered by the utilization of cold stream from LNG. The amount of usable cold is given by thermophysical properties of natural gas and corresponds to 830 kilojoule (kJ)/kg of LNG. This cold energy can be recovered during the regasification process. Regasification is carried out either in port terminals before natural gas is transported via gas lines or directly before the use of natural gas. The exploitation of cold from LNG is quite limited at present. Most of the available cold is wasted during the regasification process when LNG is heated up by water or ambient air. Wasting of cold reduces the overall efficiency of this primary energy source and leads to greater emissions. Promising ways of utilizing cold from LNG in the regasification process should be explored and implemented (Pospíšil et al., 2019).

The goal of NSPS is to reduce CH_4 emissions from the targeted sources (completions, compressors, pneumatic valves, and storage tanks) by 95 percent. NSPS implementation is applicable only to extraction and processing activities and, based on NETL's (2014) natural gas model, could reduce upstream GHG emissions from the domestic natural gas mix (which includes conventional and unconventional technologies) by 23 percent.

From a national perspective, a reduction in CH_4 emissions from natural gas systems could reduce the annual U.S. GHG inventory. In 2011, natural gas systems (processes for the extraction, processing, transport, and storage of natural gas) released 145 teragrams of CO_2e of CH_4 to the atmosphere (EPA, 2013). The total U.S. GHG inventory in 2011 was 5,800 teragrams of CO_2e, (EPA, 2013) so CH_4 from natural gas systems is 2.5 percent of the total GHG inventory. As discussed above, NSPS reductions can reduce upstream GHG emissions by 23 percent, which means they can reduce the entire U.S. GHG inventory by 0.6 percent.

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3 Air Quality

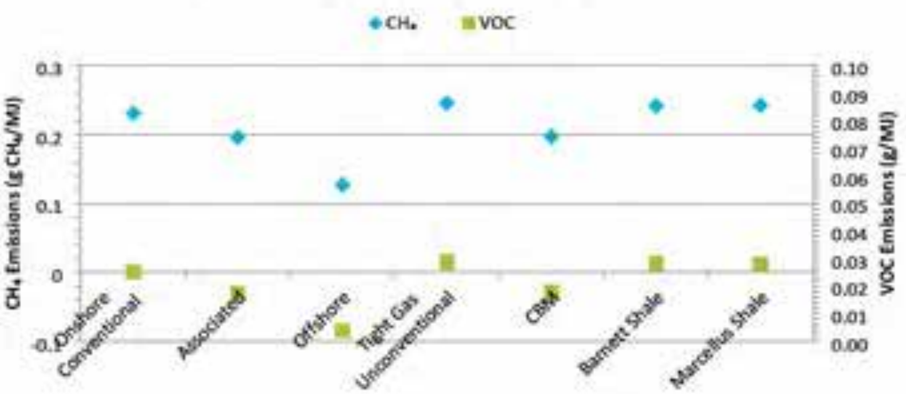
Key sources of non-GHG emissions from natural gas systems affecting air quality are as follows:

- *Uncaptured Venting*: Releases natural gas, which is a source of VOC emissions. Most uncaptured venting comes from compressor systems. Compressor systems are prevalent in most supply chain stages.
- *Fuel Combustion*: Produces a wide variety of air emissions, including NO_x, carbon monoxide (CO), sulfur dioxide (SO_2), and particulate matter (PM).

3.1 Uncaptured Venting

The venting of natural gas during extraction and processing is a key source of VOC emissions. VOCs, like CH_4, are a naturally occurring constituent of natural gas[f] and react with other pollutants to produce ground-level ozone. Since VOCs come from the same sources as CH_4, an understanding of the sources of CH_4 emissions from natural gas provides a basis for understanding the sources of VOC emissions from upstream natural gas. As shown by Exhibit 3-1, the pattern of VOC emissions among natural gas types follows the same pattern as CH_4 emissions among the same natural gas types.

Exhibit 3-1. Comparison of CH_4 and VOC emissions from upstream natural gas



The emissions (VOCs and CH_4) from offshore natural gas extraction (also shown in Exhibit 3-1) are relatively low because offshore platforms have high production rates that justify capital expenditures on loss reduction technologies which help prevent unnecessary venting. The confines of offshore extraction platforms also present a safety challenge, which requires the prevention of flammable gases, such as CH_4 or VOCs (NETL, 2014). The success of offshore

[f] Unprocessed natural gas has an average VOC composition of 18 percent by mass, and processed natural gas has a VOC composition of 5.6 percent by mass (NETL, 2014).

platforms at mitigating natural gas losses illustrates that existing technologies are effective at reducing VOC emissions from natural gas extraction. There are no technological barriers to applying such emission reduction technologies to shale gas or other sources of natural gas.

Commented [HSAJ46]: Add a reference.

The emission reduction opportunities for VOCs are the same as those for CH_4 emissions. RECs use portable equipment that captures and flares natural gas during well development. Optimized timing of plunger lifts for liquid unloading prevents unnecessary venting of natural gas from conventional onshore wells. New technologies for valve control use compressed air instead of natural gas, which prevents the venting of natural gas from the bleeding of pneumatic control lines. Dry seals for centrifugal compressors and routine maintenance of rod packing in reciprocating compressors can reduce VOC emissions from upstream natural gas. These emission reduction opportunities are targeted by the NSPS, and are estimated to be capable of reducing venting emissions, including VOCs, by 95 percent (Clark et al., 2012; NETL, 2014).

Another source of VOC emissions from the oil and gas sector is venting from condensate storage tanks (EPA, 2012b). The use of condensate storage tanks varies by region. If natural gas is produced in a region with wet gas, then the production of natural gas could result in VOC emissions from condensate storage tanks. If natural gas is produced in a region with dry gas, then the production of natural gas does not result in VOC emissions from condensate storage tanks.

A study conducted by Southern Methodist University for EDF used a bottom-up approach to calculate air emissions from natural gas extraction. The analysis focused on gas extraction in the Barnett Shale region. It categorized emissions into point, fugitive, and intermittent sources. Point sources include steady-state operation of compressors and condensate storage tanks. Fugitive sources include uncaptured gas venting from steady-state production processes. Intermittent sources represent the gas vented to the atmosphere during well development or occasional maintenance activities.

Commented [HSAJ47]: Who or what institute at SMU conducted this study? Also add reference.

The study concluded that venting from condensate storage tanks is a key contributor to the VOC inventory in the Barnett region. VOC emissions in this region are especially high in the summer when high ambient temperatures increase the venting rate of condensate storage tanks. The rate of VOC emissions from condensate storage tanks in the Barnett region has smog-forming potential comparable to the on-road vehicle emissions from the five-county region that includes Dallas-Fort Worth (Armendariz, 2009). This does not necessarily mean that the VOC emissions from condensate storage tanks in the Barnett Shale region can cause the same level of smog generated by on-road vehicles in the Dallas-Fort Worth area, just that VOC emissions have the potential. It is important to note, smog formation is a multivariable phenomenon; VOCs cause smog only when they are in the presence of NO_x emissions (EPA, 2012a).

Commented [HSAJ48]: Remove all together or add as a footnote.

In contrast to bottom-up methods for calculating air quality emissions, a study conducted by Pétron et al. (2012) with the National Oceanic and Atmospheric Administration (NOAA) modeled air quality from natural gas activity using a top-down method that divided total measured emissions from an entire region by total natural gas produced in the region (Pétron et al., 2012). The goal of the analysis was to assess the effect of rapid growth in the oil and gas industries on air quality in the Rocky Mountain region, which had over 20,000 wells in 2008. Air quality data were collected from a 300-meter-tall tower (located 35 kilometers north of Denver) and "automobile-based on-road" air sampling equipment. Pétron et al. (2012) concluded that four percent of extracted natural gas (a combination of CH_4 and VOCs) is vented. This result is higher than the natural gas leakage rates calculated by NETL and other authors (which range 2–3 percent) but is within the range of natural gas leakage rates calculated by Howarth (3.6–7.9 percent). A more detailed discussion of natural gas leakage rates is included in Chapter 2 – Greenhouse Gas Emissions and Climate Change.

Commented [HSAJ49]: Add year to complete reference.

Pétron et al. (.2012) was one of the first studies that used actual field measurements to calculate leakage rates from unconventional gas. However, the study uses data from tight gas production, so the conclusions do not necessarily apply to leakage from shale gas production. Further, researchers at the Massachusetts Institute of Technology (MIT) point out that natural gas extraction is not the only activity in northeastern Colorado that produces CH_4 and VOC emissions (O'Sullivan and Paltsev, 2012). When the air quality data were collected in 2008, most wells in the region were in tight sand formations that produced oil and gas (O'Sullivan and Paltsev, 2012). In addition to wells, the region also includes midstream processing and gathering pipelines (O'Sullivan and Paltsev, 2012).

Commented [HSAJ50]: I recommend referencing the study in place of location where the research was performed. For example, instead of MIT this should be O'Sullivan and Paltsev (2012). Same comment applies throughout the rest of this section.

Michael A. Levi, an analyst at the Council of Foreign Relations, challenges the NOAA (Pétron et al., 2012) conclusions. Levi (2012) claims that NOAA relies on "unsupported assumptions about the molecular composition of vented natural gas." Levi applies a molar ratio between CH_4 and VOCs that he believes is more consistent with the sampled region to calculate CH_4 emissions that are more consistent with bottom-up models of natural gas production. Levi's conclusions do not explicitly explain the tradeoff between CH_4 and VOC emissions (given a fixed volume of vented natural gas, the volume of CH_4 decreases as the volume of VOCs increases). Applying a lower CH_4-to-VOC ratio to top-down emission data will *reduce* the calculated CH_4 emissions but will *increase* the calculated VOC emissions.

The Arkansas Department of Environmental Quality (ADEQ) (2011) conducted an air emissions study in 2008 using a hybrid of bottom-up and top-down modeling approaches. The study was funded by a grant from EPA. EPA and ADEQ had the goal of assessing the effects of shale gas development in the Fayetteville Shale in north central Arkansas. ADEQ's study used two methods for calculating air emissions from shale gas: 1) a system-wide inventory based on emission factors and 2) ambient air monitoring. The application of emission factors to represent all natural gas development and production activity in an entire region is an example of a bottom-up modeling approach, while the interpretation of ambient air data is an example of a top-down modeling approach. Both approaches are described in more detail below.

ADEQ developed a system-wide inventory of shale gas development in the Fayetteville Shale by scaling emissions factors by 2008 gas development activity. Emission factors are observed or calculated emissions for a specific process. ADEQ focused on processes specific to hydraulic fracturing, and the operation of compressors.

ADEQ calculated annual air emissions from all hydraulic fracturing in the Fayetteville Shale by applying an emission factor of 5,000 Mcf to the 704 new wells that were completed in 2008. The chosen emission factor of 5,000 Mcf/episode was taken from a similar analysis on Barnett

Shale (Armendariz, 2009) and represents the volume of natural gas vented to the atmosphere during the hydraulic fracturing of a single well. ADEQ's emission factor represents the volume of natural gas (which includes CH_4 and VOCs) released during hydraulic fracturing, and has the same boundaries as the completion emission factors for unconventional wells as discussed in Chapter 2 – Greenhouse Gas Emissions and Climate Change (for example, NETL uses a shale gas hydraulic fracturing emission factor of 9,175 Mcf/episode) and shown in ***Exhibit 2-8***. ADEQ's emission factor (5,000 Mcf/episode) is discussed in this chapter because it was developed with the goal of evaluating shale gas emissions with impacts other than climate change.

ADEQ calculates total compressor emissions by factoring the combustion emissions from the operation of a single compressor by the 356 compressors used for natural gas distribution in the Fayetteville Shale. The emission inventory concluded that the VOC emissions from compressor stations are the largest source of VOC emissions from shale gas development in the Fayetteville Shale (ADEQ, 2011).

ADEQ used photoionization detectors to measure ambient VOC emissions in the Fayetteville Shale. A total of 14 air sampling sites were set up, including six drilling sites, three hydraulic fracturing sites, four compressor stations, and one control site. Elevated levels of VOC emission were measured near the drilling sites but were near minimum detection limits near all hydraulic fracturing sites, compressor stations, and the control site. ADEQ concluded that the open storage tanks for drilling mud and cuttings are the likely cause of elevated VOC emissions around the drilling sites. No data were collected on the composition of VOC emissions, so further data collection is necessary to assess the potential impacts of drilling VOCs on public health (ADEQ, 2011).

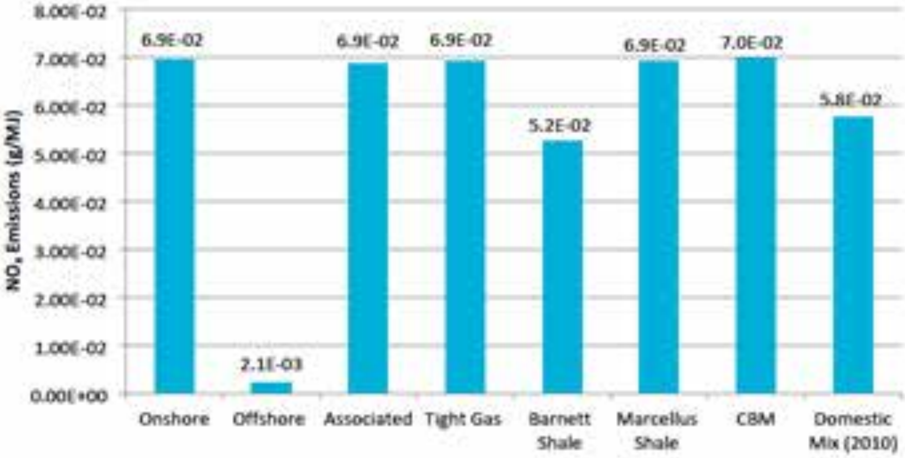
ADEQ did not identify condensate storage tanks as a significant source of VOC emissions from the development and operation of shale gas wells. The Fayetteville Shale produces dry natural gas, with heavy hydrocarbons (i.e., hydrocarbons with a higher mass than CH_4) comprising less than 0.5 percent of raw natural gas. The separation and storage of heavy hydrocarbons can be a significant source of VOC emissions for some regions. However, due to the low concentration of heavy hydrocarbons, the extraction of natural gas in the Fayetteville Shale does not have storage tanks for NGLs (ADEQ, 2011).

3.2 COMBUSTION EMISSIONS

The combustion of natural gas in compressors and gas processing equipment produces NO_x and CO. Similarly, the combustion of diesel in drilling equipment produces NO_x and CO, as well as significant quantities of PM and SO_2 emissions. The generation of grid electricity (used by a small share of natural gas compressors) produces these air pollutants as well.

Exhibit 3-2 illustrates direct NO_x emissions from extraction activities as well as indirect NO_x emissions from the generation of electricity and other ancillary processes (NETL, 2014). NO_x emissions from Barnett Shale extraction and processing are 23 percent lower than those from Marcellus Shale extraction and processing. A key exception in these exhibits is the emissions from offshore extraction; offshore extraction platforms use centrifugal compressors, which have lower combustion emission factors than the reciprocating compressors used at onshore extraction sites (NETL, 2014).

Exhibit 3-2. NO_x emissions from natural gas extraction and processing



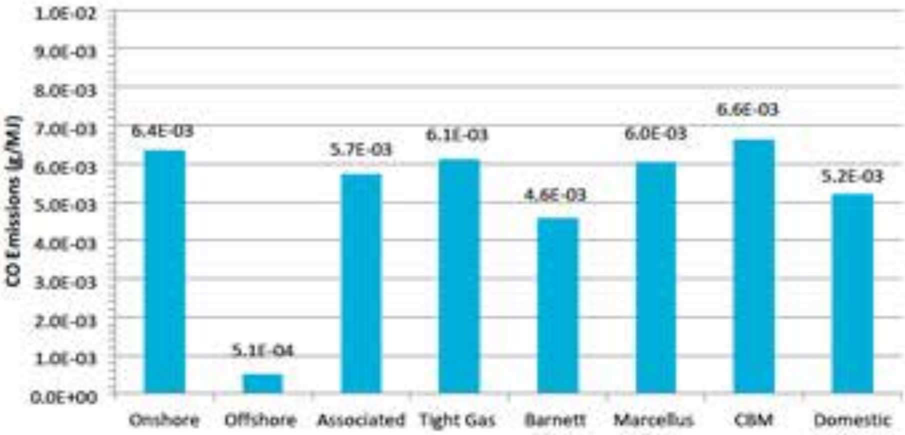
The EDF analysis of the Barnett Shale also applied a bottom-up approach to calculate combustion emissions from natural gas production. They estimated region-wide compressor exhaust emissions of 46 tons of NO_x emissions per day. For comparison, they point out that the combined NO_x emissions from all airports in the area of the Barnett Shale region produce 14 tons of NO_x emissions per day. Suggesting the NO_x inventory from shale gas production in the Barnett Shale is at least three times higher than the NO_x inventory from area airports (Armendariz, 2009).

There are options for reducing NO_x emissions from natural gas production. One option for NO_x emissions reduction is the replacement of gas-fired compressor engines with electrically-powered compressors (ADEQ, 2011). Extraction sites in remote areas may not be near the electricity grid, but if electricity is available, the use of electrically-powered equipment can be a cost-effective way to reduce direct combustion emissions.

Increased use of electricity will increase indirect emissions of NO_x; however, as shown in Exhibit 3-2, which includes direct and indirect emissions, total NO_x emissions from Barnett Shale extraction are lower than those from other natural gas extraction sources. The one exception to this conclusion is offshore extraction, which uses centrifugal compressors that have lower NO_x emissions than the reciprocating compressors used by onshore technologies (NETL, 2014). As discussed in Chapter 2 – Greenhouse Gas Emissions and Climate Change, natural gas pipelines can also use electrically-powered compressors to meet local emission regulations and limit the use of internal combustion engines (Hedman, 2008).

NETL's conclusions for CO emissions are the same as their conclusions for NO_x emissions (NETL, 2014). The CO emissions from unconventional natural gas are comparable to those from conventional natural gas. This is illustrated in Exhibit 3-3, which compares CO emissions among different natural gas types (NETL, 2014). (Again, offshore extraction has low CO emissions, because it uses centrifugal compressor technology.)

Exhibit 3-3. CO emissions from natural gas extraction and processing



According to ADEQ (2011), the combustion of natural gas does not produce significant PM and SO_2 emissions, but the use of diesel engines by drill rigs produces PM and SO_2 emissions. ADEQ's (2011) assessment of Fayetteville Shale identifies the use of drilling rigs during well completion as the largest source of PM emissions from gas production. NETL's assessment of natural gas shows that PM emissions are of the same order of magnitude for all natural gas sources (on the order of magnitude of 0.0001 g/MJ of gas extracted).

Indirect energy consumption can also affect the air quality profile of a gas extraction technology. If the development or operation of a natural gas well uses grid electricity, then the fuel mix of the electricity grid will affect the life cycle performance of the well. The indirect air quality impacts of electricity consumption depend on the fuel mixes and combustion characteristics of power plants that compose a regional electricity grid. For example, NETL's results show variance in SO_2 emissions among natural gas types. The SO_2 emissions from Barnett Shale are an order of magnitude greater than the SO_2 emissions from other onshore natural gas extraction technologies. This difference is due to the use of electricity by a portion of the compressors in the Barnett Shale. The fuel mix for grid electricity includes the combustion of coal, which is a source of SO_2 emissions (NETL, 2014).

3.3 Air Quality Studies on Venting and Combustion Emissions

Due to concerns about the air quality impacts from shale gas development, the East Texas Council of Governments commissioned an air quality assessment of the Haynesville Play, which as of December 2012 had nearly 3,000 shale gas wells (Environ, 2013). The air quality assessment collected data for VOC, NO_x, and CO emissions. The largest sources of these emissions were fugitive releases and combustion emissions from gas processing equipment and compressors. Compressors and gas processing equipment account for 79.7 percent of NO_x emissions and 90.1 percent of VOC emissions in the study. Fuel consumption by drilling rigs accounts for a smaller share of emissions—drilling rigs account for 16 percent of NO_x, and 1.2 percent of VOC emissions. Hydraulic fracturing accounts for less than 2 percent of NO_x emissions and less than 1 percent of VOC emissions. The authors acknowledge that there is significant uncertainty associated with future year projections of regional air emissions, but conclude that continued development of Haynesville Shale gas, even at a slow pace, will be large enough to affect the ozone levels in northeast Texas (Environ, 2013).

Litovitz et al. (2013) estimated the air pollutants from shale gas extraction in the Pennsylvania portion of the Marcellus Shale. They estimated VOC, NO_x, PM, and SO_2 pollutants by analyzing data for diesel trucks, well development (including hydraulic fracturing), natural gas compressor stations, and other natural gas extraction activities. They then scaled their estimates to the county and state levels. They concluded that compressor station activities account for at least 60 percent of extraction-related emissions; development activities, which include hydraulic fracturing, account for, at most, a third of extraction-related emissions. Litovitz et al. (2013) also compared the estimated pollutants from shale gas production to other industrial activities in Pennsylvania. They estimated emissions of VOC, PM, and SO_2 from shale gas production account for less than 1 percent of total air pollutants from all industrial sectors in Pennsylvania; NO_x emissions represent a higher share of total industrial air pollutants, at 2.9 to 4.8 percent of total industrial air pollutants. Shale gas air pollutants may be a small portion of state-wide industrial emissions, but they are not evenly distributed across the state. In counties with the most shale gas extraction, county-aggregated NO_x emissions are higher than the NO_x emissions from a major source, such as a power plant (Litovitz et al., 2013).

Further data collection efforts are necessary to characterize the regional variation in the volume and composition of vented natural gas. The University of Texas at Austin is leading a team of engineering firms and producers to measure CH_4 emissions from hydraulically fractured wells in the Barnett, Eagle Ford, Fayetteville, Haynesville, Denver-Julesberg, and Marcellus regions (Dittrick, 2012). NETL (2013) has air quality sampling in progress, which is using mobile equipment to measure VOCs and other air quality metrics in the Marcellus region.

SEAB views shale gas production as a key opportunity for increasing the U.S. natural gas supply but recommends the use of emission control technologies. SEAB recommends the use of state and federal regulations for timely implementation of emission control technologies. For example, the NSPS rules and National Emissions Standards for Hazardous Air Pollutants for the oil and gas sector will reduce smog precursors and other harmful pollutants. As noted by SEAB, a limitation of the new NSPS[g] rules are that they do not apply to existing shale gas wells unless the wells are re-fractured. Further, producers should also be expected to "collect and publicly share" emissions data (SEAB, 2011).

[g] Since NSPS rules reduce total gas leakage, they have the two-fold benefit of reducing CH_4 emissions (as discussed in Chapter 2 – Greenhouse Gas Emissions and Climate Change) as well as VOC emissions. NSPS implementation has climate and air quality benefits.

3.4 References

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4 WATER USE AND QUALITY

The literature describes the treatment and management of wastewaters as the central environmental concern regarding natural gas production in the eastern states, where water is abundant. To the west, where drier climates can limit the availability of freshwater, and deep underground injection wells for wastewater disposal are more readily available, the central concern discussed in the literature is the availability of water for drilling and hydraulic fracturing. It is estimated that drilling and hydraulically fracturing a shale gas well can consume between 2–6 MM gallons (gal) of water. As such, even the smallest local or seasonal water supply shortages can cause issues, even though water consumption for natural gas production generally represents less than 1 percent of regional water consumption (DOE, 2009). Water quality can be impacted due to inadequate management of water and fracturing chemicals on the surface, both before injection and after flowback and produced water. Subsurface impacts can result from the migration of fracturing fluids, formation waters, and CH_4 along well bores and through rock fracture networks. Management and disposal of wastewaters increasingly includes efforts to minimize water use and recycling and re-use of fracturing fluids, in addition to treatment and disposal through deep underground injection, with the risk of induced seismicity.

Commented [HSAJS1]: Water quality?

4.1 WATER USE FOR UNCONVENTIONAL NATURAL GAS PRODUCTION

Water is used in unconventional natural gas production and, to a lesser extent, in the associated infrastructure for gas processing and testing pipelines (KPMG, 2012). Most of the water used for unconventional natural gas production is used for drilling for hydraulic fracturing. For example, of the total water used by the shale gas industry, hydraulic fracturing consumes about 89 percent, drilling uses 10 percent, and infrastructure consumes the remainder (Hayes and Severin, 2012). Water is also the main component of the fluids used for hydraulic fracturing, making up approximately 99 percent of the total volume.

Details on the types of chemicals and other agents combined with water used during well drilling and hydraulic fracturing are provided in Section 4.2.1. Segall and Goo (2011) cited SEAB (2011) in reporting that hydraulic fracturing uses 1–5 MM gal of water per well. Reduced surface water availability can harm ecosystems and human communities and groundwater withdrawals can permanently deplete aquifers. Hydraulic fracturing fluids, flowback water, and produced waters can pose risks to water quality. Proper treatment of these fluids is essential to protecting water resources.

Commented [HSAJS2]: Reduced surface water availability due to withdraws for fracking? This is an important consideration.

4.1.1 Water Consumption

DOE (2013) examined current and potential future impacts on the U.S. energy sector from three climate trends: increasing air and water temperatures, decreasing water availability, and increasing intensity and frequency of storms. DOE found that, in addition to being vulnerable to other trends, unconventional oil and gas production is vulnerable to decreasing water availability. Disruption of energy infrastructure in coastal regions due to storms and sea-level rise could also disrupt production. DOE cites two recent events as examples of impacts to the industry from decreasing water availability. In 2011, Grand Prairie, Texas (followed by other local water districts) restricted the use of municipal water for hydraulic fracturing and in the summer of 2012, operators in Kansas, Texas, Pennsylvania, and North Dakota faced higher water costs and were denied access to water usage for at least six weeks due to drought conditions (DOE, 2013).

The GAO (2010) examined the environmental impacts associated with commercial oil shale development, because oil shale, like natural gas from shales, uses substantial amounts of water. The GAO noted that the magnitude of impacts on water availability and quality from oil shale development is unknown. While water would likely be available during initial development of an oil shale industry, the size of the industry, particularly in Colorado and Utah, could eventually be constrained by the availability of water. Similar concerns have arisen for shale gas development in arid regions.

Water consumption per shale gas well can vary due to four sets of conditions:

- *Geology*: maturity of the shale and formation depth, thickness, and lateral extent
- *Technology*: horizontal and vertical drilling, water recycling
- *Operations*: operator decisions, availability of nearby freshwater
- *Regulatory*: requirements for use and treatment of water.

Drilling a shale gas well can consume between 65,000–1 MM gal of water or more, depending on the depth, horizontal length, and the geology of the formations through which the hole is drilled (see Exhibit 4-1) (DOE, 2009; Mathis, 2011; GAO, 2012a). Hydraulic fracturing can use 2–6 MM gal of water, which can be more than 95 percent of the water use per borehole as a single borehole can be hydraulically fractured multiple times (CRS, 2009). Nicot and Scanlon (2012) note that water use per well has increased over the last ten years as the lateral lengths and number of fracking stages has increased.

Exhibit 4-1. Average freshwater use per well

Shale Play	DOE (2009) (gal)			Mathis (2011) (gal)			GAO (2012a) (gal)		
	Drilling	Fracking	Total	Drilling	Fracking	Total	Drilling	Fracking	Total
Barnett	400,000	2,300,000	2,700,00	250,000	3,800,000	4,050,000	250,000	4,600,000	4,850,000
Eagle Ford	—	—	—	125,000	6,000,000	6,125,000	125,000	5,000,000	5,125,000
Fayetteville	60,000	2,900,000	3,060,000	65,000	4,900,000	4,965,000	—	—	—
Haynesville	1,000,000	2,700,000	3,700,000	600,000	5,000,000	5,600,000	600,000	5,000,000	5,600,000
Marcellus	80,000	3,800,000	3,880,000	85,000	5,500,000	5,585,000	85,000	5,600,000	5,685,000
Niobrara	—	—	—	300,000	3,000,000	3,300,000	300,000	3,000,000	3,300,000

EPA estimated that if 35,000 wells per year were hydraulically fractured in the United States, these wells would consume the equivalent of the water consumed by 5 MM people (Groat and Grimshaw, 2012). This scale of development was achieved during early shale gas activity when approximately 35,000 shale gas wells were drilled in 2006 (Halliburton, 2008). Data on the number of shale gas wells developed each year since 2006 was not able to be identified. However, the decline in the number of active natural gas drilling rigs over the last few years indicates a decline in the number of shale gas wells that are drilled annually. The weekly natural gas rig count has decreased nearly four-fold since early 2007, from approximately 1,600 active rigs to 400 active rigs (EIA, 2014).

Commented [HSAJ53]: New rigs?

Published estimates of water use typically rely on operator reports. DOE (2009) noted that the volumes reported are "approximate" and come from Chesapeake Energy (Satterfield et al., 2008) and personal communications with operators. Mathis (2011) also presented Chesapeake Energy data. The GAO (2012a) cites data reported by Apache Corporation. Nicot and Scanlon (2012) cite data that the Texas Railroad Commission collects from operators.

CBM wells can also be hydraulically fractured but use significantly less water than shale wells. Published reports indicate that a hydraulic fracturing treatment in a CBM well can use 50,000–350,000 gal of fluids and 75,000–350,000 pounds of sand proppant. Operator data suggests that the maximum average injection volume is 150,000 gal/well and the median volume of 57,500 gal/well (EPA, 2004).

Mielke et al. (2010) summarized the water intensity of various energy sources (see Exhibit 4-2). Natural gas is among the most water-efficient resources. If the amount of water used for shale gas production seems high, it is still less water-intense than the production of many other sources of energy, or the amount of water needed to produce an amount of energy, typically expressed in gal/MM British thermal units (Btu).

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Exhibit 4-2. Ranges of water intensity of energy sources

Energy Source	Range in Water Intensity (gal/MMBtu)
Conventional Natural Gas	~0
Shale Gas	0.6–1.8
Coal (no slurry transport)	2–8
Nuclear (uranium at plant)	8–14
Conventional Oil	1.4–62
Oil Shale Petroleum (mining)	7.2–38
Oil Sands Petroleum (in situ)	9.4–16
Synfuel (coal gasification)	11–26
Coal (slurry transport)	13–32
Oil Sands Petroleum (mining)	14–33
Synfuel (coal Fischer-Tropsch)	41–60
Enhanced Oil Recovery	21–2,500
Fuel Ethanol (irrigated corn)	2,500–29,000
Biodiesel (irrigated soy)	13,800–60,000

Conventional natural gas production requires some water for drilling, primarily for drilling mud, and to cool and lubricate the drill bit, but otherwise may use 1–3 gal/MMBtu for processing and pipeline transport (Mielke et al., 2010). Similarly, water intensity for shale gas drilling ranges 0.1–1.0 gal/MMBtu, but hydraulic fracturing has an intensity of about 3.5 gal/MMBtu. With per-well reserves ranging 2.0–6.5 Bcf, shale gas uses 0.6–1.8 gal/MMBtu with the additional water relative to conventional production needed for hydraulic fracturing (Mielke et al., 2010).

Just as water demand varies by shale play and local conditions, the water intensity also varies by play; for example, water intensity in the Fayetteville at 1.7 gal/MMBtu and the Barnett at 1.5 gal/MMBtu) are greater than in the Marcellus (1.3 gal/MMBtu) or the Haynesville (0.8 gal/MMBtu). These differences, in part, reflect greater reserves per well in the latter two plays (Mielke et al., 2010).

In contrast to shale gas, petroleum from oil shales takes more water for mining and processing or retorting, which uses steam. Oil shales are either mined with surface retorting or undergo in situ retorting to release the oil for extraction through wells. Although data are limited due to the lack of commercial production, available estimates indicate a water intensity of oil shale mining of 7.2–38 gal/MMBtu, and 9.4–16 gal/MMBtu for in situ production (Mielke et al., 2010).

Furthermore, water use in the major shale plays represents only a small fraction of total water use in the regions surrounding the plays. Exhibit 4-3 lists the various uses for water in four representative plays, as percentages of the consumption. The Barnett Shale underlies the Dallas-Fort Worth metropolitan area. More than 80 percent of the water in the area goes to public supplies. In contrast, the Marcellus underlies both populated and industrialized areas where more than 70 percent of water is used for power generation. The Fayetteville area, underlying a rural and agricultural area in Arkansas, consumes more than 60 percent of its water for irrigation. In the Haynesville, beneath eastern Texas and western Louisiana, water is used for multiple purposes, but more than 45 percent goes to public supply. Shale gas production typically consumes less than 1 percent of total water demand, except in arid regions like the Eagle Ford where it is 3–6 percent.

Exhibit 4-3. Total water use for four major shale plays

Play	Public Supply (%)	Industry & Mining (%)	Power Generation (%)	Irrigation (%)	Livestock (%)	Shale Gas (%)	Total Water Use (B gal/yr)
Barnett[A]	82.7	4.5	3.7	6.3	2.3	0.4	133.8
Eagle Ford[B]	17	4	5	66	4	3 – 6	64.8
Fayetteville[A]	2.3	1.1	33.3	62.9	0.3	0.1	378
Haynesville[A]	45.9	27.2	13.5	8.5	4.0	0.8	90.3
Marcellus[A]	12.0	16.1	71.7	0.1	0.01	0.06	3,570
Niobrara[C]	8	4	6	82		0.01	1,280

[A] From Arthur, 2009
[B] From Chesapeake Energy, 2012a
[C] From Chesapeake Energy, 2012b

Nonetheless, water presents logistical and cost challenges to shale gas operators. IHS (2012) estimates that lifecycle water management costs, including sourcing, treatment, transport, and disposal, can account for 10 percent of the operating cost of a hypothetical well in the Marcellus.

4.1.2 Sources of Water and Environmental Impacts

Unconventional natural gas producers generally withdraw water from local surface water and groundwater sources for drilling and hydraulic fracturing (DOE, 2009). So, while production uses a relatively small fraction of all local water withdrawals, to water availability have been cited as a concern, as well as the longer-term prospect for water supplies in some areas.

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Water withdrawals from surface water sources like streams and rivers can decrease downstream flows, which can render these sources more susceptible to changes in temperatures. Reduced in-stream flows can damage riparian vegetation and affect water availability for wildlife. Water withdrawals from shallow aquifers can affect these resources by lowering water levels and reducing flows to connected springs and streams, compounding the effects on surface water bodies. Deeper aquifers are also susceptible to longer-term effects on groundwater flow because recharge to deeper aquifers by precipitation takes longer. Surface water and groundwater withdrawals can also impact the amount of water available for other uses, including potable water supplies. Freshwater is a limited resource in arid and semiarid areas where expanding population and shifting patterns in land use place additional demands on water supplies. Prolonged drought conditions and weather projections associated with warming climates may exacerbate the future availability of water in some parts of the country (GAO, 2012a).

Water demand for unconventional natural gas production is not confined to shale gas and hydraulic fracturing. Gas production from CBM formations poses risks to aquifers as water in the coal bed is removed to lower reservoir pressures and induces CH_4 to desorb water from the coal. According to the USGS, dewatering CBD formations in the Powder River Basin in Wyoming can lower the groundwater table and reduce water available for other uses, such as livestock and irrigation (GAO, 2012a).

Water rights and supplies, which are typically regulated at the state level, reflect the greater general availability of water in the eastern United States. Historical trends in water use have created doctrinal differences in water laws so that east of the Mississippi River, where water tends to be more plentiful, states apply a riparian doctrine, where a water user who owns land adjacent to a water body has a right to make reasonable use of that water. In the West, where water can be scarcer, states apply a doctrine of prior appropriation, where a water user's reasonable and beneficial use of water remains subject to state permits that are generally issued on a first-come, first-served basis (CRS, 2009). In some states, water rights are allocated according to water budgets for individual basins or watersheds, as determined by a state hydrologist or water authority.

4.1.3 Shale Play Water Supply Examples

Case studies of the larger and more active shale gas plays provide a geographically distributed overview of the water demand and supply issues noted in the literature. General properties of the shales discussed are shown on Exhibit 4-4.

Exhibit 4-4. Properties of shale plays

Formation	Age	Depth (ft)	Thickness (ft)	Area (mi^2)	Location
Barnett Shale	Mississippian	6,500–8,500	100–600	18,720	Texas
Eagle Ford Shale	Cretaceous	4,000–12,000	250	20,000	Texas
Fayetteville Shale	Mississippian	1,000–7,000	20–200	9,000	Oklahoma and Arkansas
Haynesville Shale	Jurassic	10,500–13,500	200–300	9000	Texas and Louisiana
Marcellus Shale	Devonian	4,000–8,000	50–200	95,000	New York, Pennsylvania, West Virginia, Maryland, Virginia, Ohio

4.1.3.1 Barnett Shale

The Barnett Shale is a Mississippian-age shale that occurs at depths of 6,500–8,500 feet and thicknesses of 100–600 feet in the Fort Worth Basin in northcentral Texas (DOE, 2009). The Barnett covers 48,000 square kilometers (km^2) and underlies 20 counties, including the Dallas-Fort Worth metropolitan area. However, production from the Barnett comes primarily from the six counties surrounding Fort Worth (Wise, Denton, Parker, Tarrant, Hood, and Johnson) (Galusky, 2009).

Nicot and Scanlon (2012) quantified water use in the three Texas plays (i.e., Barnett, Eagle Ford, and Haynesville) based on operator data submitted to the Texas Railroad Commission. With more than 14,900 wells as of June 2011, water use per well ranges 0.75–5.5 MM gal, while median water use per horizontal well is 2.8 MM gal.

In 2007, 59 percent of the water used for natural gas production in the Barnett region came from surface water, 41 percent from groundwater, and less than 1 percent from reuse and recycling, which was projected to require less than 1 percent of regional surface water supplies and less than 10 percent of groundwater (Galusky, 2007). Public water supply in the Dallas-Fort Worth metropolitan area is the largest user, making up almost 83 percent of total demand in the area (Arthur, 2009).

A combination of growing population, drought conditions, and natural gas production raised concerns about the sustainability of local groundwater resources (Bené et al., 2006). The area has depended on the Trinity and Woodbine aquifers for more than a century, and this has resulted in declining water levels. As pressure on these aquifers has increased, additional surface water resources have been developed. In 2006, local natural gas producers formed the Barnett Shale Water Conservation and Management Committee, who have made it their mission to develop best management practices for water use.

Between April 2006 and November 2013, the Barnett Shale Water Conservation and Management Committee released at least 17 reports on water management, recovery and reuse, and alternative sources. One of their first initiatives was to commission a study on present and projected water use (Galusky, 2007), including projections published by the Texas Water Development Board (TWDB) (Bené et al., 2006). Bené et al. (2006) note that water demand projections depend on population growth estimates, while demand for other uses, including shale gas projection, are driven by economic assumptions. They projected growth of total water use in the area from about 1.0 billion (B) barrels (bbl) (423.6 B gal) per year in 2000 to 16.3 B bbl (684.3 B gal) per year in 2025, a 62 percent increase. They conclude that projections of groundwater use are regionally sustainable, but that continued development will have localized impacts. Further demands on the western parts of the Trinity aquifer in response to population growth, the Trinity aquifer may not be a reliable, long-term source of water for all users. Additional sources and distribution infrastructure could become necessary.

Galusky (2009) revisited his original assessment in the wake of declining natural gas prices in 2008–2009, as the number of well completions in the Barnett dropped by more than half in 2009, to fewer than 1,500 from about 3,000 in 2008. The previous forecasts (Galusky, 2007; Bené et al., 2006) indicated that the fraction of total freshwater from all sources would be less than 2 percent over the course of drilling the Barnett Shale. Galusky (2009) concluded that water use for Barnett Shale gas production may be less than 1.5 percent of regional supplies during periods of peak demand. Nicot and Scanlon (2012) also concluded that water use for shale gas production remains comparatively minor (less than 1 percent) at the regional and state levels, relative to irrigation (56 percent of state-wide water use) and municipal supplies (26 percent state-wide). However, they note that shale gas does consume a much higher percentage of localized water use. In some counties within the Barnett region, shale gas production uses more than 40 percent of groundwater, and as much as 29 percent of total net water use. Projected net water use in some counties could reach as much as 40 percent of the total during peak production years.

4.1.3.2 Eagle Ford Shale

The Eagle Ford Shale is a Cretaceous age formation that trends in an arc parallel to the Texas Gulf Coast from the Mexican border into east Texas, about 50 miles wide and 400 miles long with an average thickness of 250 feet at a depth of approximately 4,000–12,000 feet. It underlies 25 mainly rural counties, passing south of San Antonio and ending west of Houston. The major uses for water in the region are irrigation (66 percent) and public supply (17 percent). Water for shale gas production consumes 3–6 percent of the total water use; the primary sources are groundwater from the Carrizo-Wilcox aquifer in the northern portion of the play, and the Gulf Coast Aquifer to the south (Jester, 2013).

“Water availability” is defined by the TWDB (2012) as “how much water would be available if there were no legal or infrastructure limitations.” In contrast to water availability, the TWDB (2012) defines “water supply” as the amount of water that is provided by existing wells, pipelines, and other infrastructure. The TWDB (2012) projects that water availability from the Carrizo-Wilcox aquifer will decline slightly, by about 1 percent, between 2010 and 2060; water availability from the Gulf Coast aquifer will decline by 15 percent over the same period, mainly due to restrictions on withdrawals to prevent land surface subsidence. Despite the declines in water availability from the Carrizo-Wilcox and Gulf Coast aquifers, the TWDB (2012) projections show that the water available from these aquifers will exceed the water supply capacity within the Eagle Ford region through 2060.

In 2010, the mining sector, which includes natural gas wells, accounted for 1.6 percent of Texas's water demand. The TWDB (2012) projects that this demand will be 1.3 percent of state water demand in 2060. Irrigation and municipal use account for most of the total water used in Texas. In 2010, irrigation and municipal users accounted for 56 and 27 percent, respectively, of state water demand. The TWBD (2012) projects that in 2060, irrigation and municipal water demand will each represent a 38 percent share of state water use (or, in total, 76 percent of state water use).

The Eagle Ford Task Force, appointed by the Texas Railroad Commission, evaluated data on water usage in the Eagle Ford region and concluded that the Carrizo Wilcox Aquifer contains enough water to support continued oil and gas development. Groundwater supplies about 90 percent of the water; oil and gas production, among other mining activities, will consume about 1.5 percent of total water usage in 2060. Water use for hydraulic fracturing is forecast to increase for about the next ten years to about 271 MM bbl (11.4 B gal) per year, and then decline as water recycling technologies improve (Porter, 2013).

Nicot and Scanlon (2012) quantified net water use for shale gas production using data from Texas, which is the dominant producer of shale gas in the United States. Water use in the Eagle Ford play is increasing rapidly; cumulative use (2008–mid-2011) has been 11.4 MM bbl (4.8 B gal). Further, the authors point to counties where projected local use represents a very high proportion of total water use. Projected net water use for shale gas production in peak years could consume more than 30 percent of net water use (DeWitt County: 35 percent; Dimmit County: 55 percent; and Karnes County: 39 percent). In LaSalle County, net water usage may climb as high as 89 percent of net water use, relative to 2008 total net water use. Potential impacts are primarily in competition with other users for surface water resources, which are sensitive to public supplies for increasing populations and cyclic periods of wetter and drier weather. Stress to groundwater supplies shows that impacts to surface water features like springs and streamflows and, in some cases, land subsidence (Nicot and Scanlon, 2012).

4.1.3.3 Fayetteville Shale

The Fayetteville Shale is a Mississippian age formation that straddles approximately 9,000 square miles (mi^2) of eastern Oklahoma and northern Arkansas at depths of 1,000–7,000 feet with a pay zone thickness of 20–200 feet (DOE, 2009). Pay zones are areas within a shale gas formation that, due to lithologic or fracturing differences, tend to produce more gas or produce gas more economically. Total water use in the region in 2005 was 31.9 B bbl (1.34 trillion [T] gal). Irrigation accounts for 62.9 percent of water use in the region and power generation another 33.3 percent. Shale gas production accounts for less than 1 percent of water use (Arthur, 2009).

Veil (2011) calculated the total water demand for natural gas production from the Fayetteville based on historical drilling records and estimates of water consumption per well. A high-production scenario consumes an annual volume of 4.1–5.8 B gal/year. Assuming drilling and water use are distributed evenly through the year, this translates to 11.2–15.8 MM gal/day, less than one percent of total state-wide water use in Arkansas. Veil concluded that there is sufficient water available to support natural gas development but noted that not all sources of surface water will be sufficient, nor that water should be withdrawn at the same rates through the year. Veil recommends that gas producers plan and store water during wet periods to ensure its availability when needed.

4.1.3.4 Haynesville Shale

The Haynesville Shale (also called the Haynesville/Bossier) is a Jurassic-aged formation that underlies 9,000 mi^2 of eastern Texas and northern Louisiana at depths of 10,500–13,500 feet with an average thickness of 200–300 feet (DOE, 2009). Total water use in the Haynesville region that covers eight parishes in northwestern Louisiana and six counties in eastern Texas totals 2.15 B bbl per year (90.3 B gal). The major users are public supply (45.9 percent), industry and mining (27.2 percent), and power generation (13.5 percent). Shale gas production consumes approximately 0.8 percent (Arthur, 2009).

The Texas portion of the Haynesville used 1.7 B gal (2008–mid-2011). In 2017, the projected peak production year, water demand could exceed 136 percent of total county water use for San Augustine County, Texas, 55 percent in Shelby County, and 30 percent in Panola County. Greater precipitation in the Haynesville region than in the Eagle Ford makes surface water resources more abundant but use for shale gas production can impact local streamflows. Similarly, groundwater resources remain readily available, but future conflicts with other users, including public supply and industrial users are possible (Nicot and Scanlon, 2012).

4.1.3.5 Marcellus Shale

The Marcellus Shale is a Middle Devonian-age formation that sprawls across 95,000 mi^2, underlying parts of six states, including 10 counties in southern New York, 32 counties in central Pennsylvania, 29 counties in northern West Virginia, five counties in western Maryland and Virginia, and three counties in eastern Ohio. The Marcellus is 50–200 feet thick at depths of 4,000–8,000 feet (DOE, 2009). Total annual water use in the region is 85 B bbl (3.75 T gal). The major consumers are power generation (71.7 percent), industrial and mining (16.1 percent), and public supply (12.0 percent) (Arthur, 2009). Shale gas production consumes 0.19 percent (Groat and Grimshaw, 2012).

Representative of the Marcellus region, Pennsylvania receives more than 40 inches per year in annual precipitation and has abundant supplies of water with more than 1.9 T bbl (80 T gal) as groundwater, and 58.1 B bbl (2.5 T gal) in surface waters. Despite the size of the groundwater resource, groundwater withdrawals make up just 7 percent of supply, and surface water withdrawal accounts for more than 9 percent of the annual total. As an indicator of water supply for shale gas production, during 2008–2010, water for hydraulic fracturing in the Susquehanna River Basin in central Pennsylvania came from surface water sources (71 percent) and municipal supplies (29 percent) (Abdala and Drohan, 2010).

Despite the ease of water availability in the Marcellus region, water resources agencies and citizens in the Marcellus region have expressed concerns over the local availability of water supplies for natural gas production. Hydraulic fracturing may need up to 3 MM gal of water per treatment and, under drought conditions or in areas with stressed water supplies, adequate supplies for drilling and fracturing could be difficult. In addition to impacting local water resources, concerns include watershed degradation from heavy equipment movement on rural roads, and proper methods for disposing of potentially contaminated fluids from the shale gas wells (Soeder and Kappel, 2009).

4.1.4 Potential Alternatives to Freshwater Use

Increasing demand for water for drilling and hydraulic fracturing shale gas plays has driven operators to seek supplemental sources of water, and alternatives to local freshwater sources. Potential alternative sources include industrial wastewater, water treatment plant outflows, abandoned mine waters, saline groundwater, and reuse of produced waters.

Water use for shale gas in Texas (Barnett, Eagle Ford, and Haynesville) is less than 1 percent of statewide withdrawals; however, local impacts vary with water availability and competing demands. Projections of cumulative net water use during the next 50 years for all plays total about 27.4 B bbl (1.15 T gal), peaking at 9.1 B bbl (38.3 B gal) in the mid-2020s and decreasing to 23 MM bbl [6 B gal] in 2060. The authors note that current freshwater use may shift to brackish water to reduce competition with other users.

Hayes and Severin (2012) report on an investigation of alternative sources of water in the Barnett that analyzed three potential sources: treated wastewater outfalls, small bodies of surface water outside state regulation, and small groundwater sources outside the main Trinity aquifer. Their results indicate that all three of these sources are susceptible to drought conditions, and that such fragmented sources involve dispersed ownership and increased costs to gather these waters.

One alternative source of water is seasonal changes in river flow; states and operators capture water when surface water flows are greatest (DOE, 2009). This echoes a recommendation by Veil (2011) to operators in the Fayetteville to store water during wet periods to ensure its availability during drier periods. However, this requires operators to use or develop places to store water and adds costs for the collection and storage.

Drilling with compressed air offers an alternative to drilling with fluids, due to the increased cost savings from both reduction in mud costs and the shortened drilling times as a result of air-based drilling. The air, like drilling mud, functions to lubricate, cool the bit, and remove cuttings. Air drilling is generally limited to low pressure formations, such as the Marcellus Shale in New York (DOE, 2009).

One of the preferred options is the reuse of produced water from prior hydraulic fracturing jobs. Mantell (2011) describes three factors that control the feasibility of reuse:

- *Quantity* of water produced, including the initial volumes of flowback water
- *Duration* of production and declines over time

- *Continuity* to keep tanks and trucks moving to increase efficiency

The Barnett, Fayetteville, and Marcellus all produce substantial volumes of water, starting with 500,000–600,000 gal/well in the first ten days, or enough to meet 10–15 percent of the total water needed for a new well. The Haynesville produces less water, typically 250,000 gal in the first ten days, or about 5 percent of the water for the next well (Mantell, 2011).

The treatment of produced water is discussed in Section 4.2.3 and Section 4.2.4.2.

4.2 Potential Impacts to Water Quality

The GAO reviewed studies indicating that shale gas development can pose risks to water quality as a result of erosion from ground disturbances, spills and releases of chemicals and other fluids, or underground migration of gases and chemicals. Spilled, leaked, or released chemicals or wastes can flow into surface waters or infiltrate into groundwaters to contaminate subsurface soils and aquifers (GAO, 2012a).

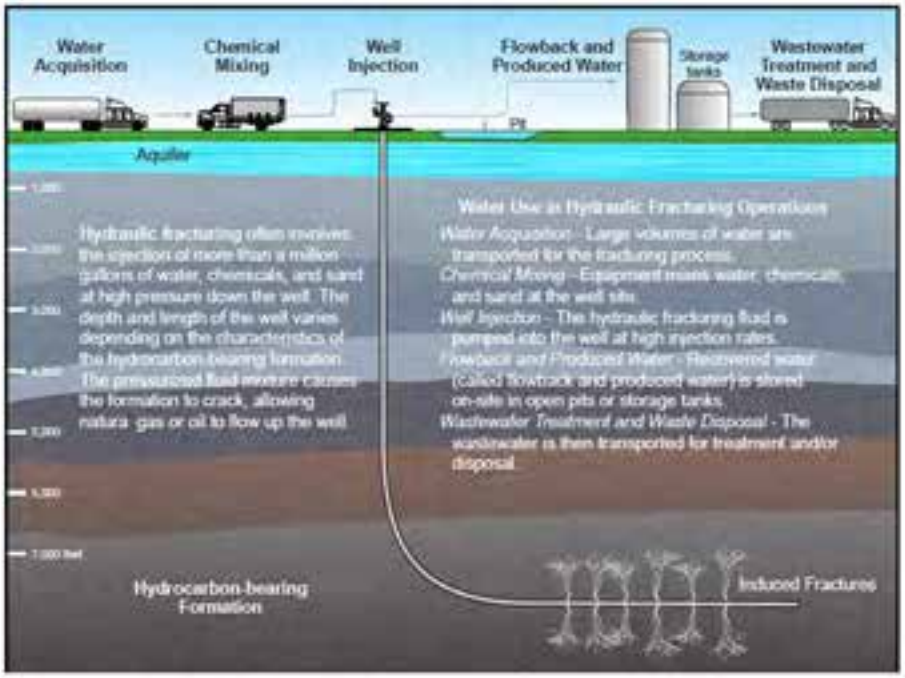
Vengosh et al. (2013) describe three potential risks to the quality of U.S. water resources: 1) contamination of shallow aquifers, primarily due to inadequate well construction; 2) hydraulic pathways connecting deep gas-bearing formations with shallower aquifers; and 3) inadequate disposal of produced and flowback waters.

EPA (2013) distinguishes four stages during hydraulic fracturing water cycle where the use of water and hydraulic fracturing chemicals could lead to possible impacts on drinking water quality:

- *Chemical Mixing*: Surface spills of hydraulic fracturing fluids on or near well pads and stormwater runoff can impact surface and groundwater resources.
- *Well Injection*: Fluid injection and fracturing processes can result in loss and migration of fluids in the subsurface.
- *Flowback and Produced Water*: Surface spills of flowback and produced water on or near well pads can impact surface and groundwater resources.
- *Wastewater Management and Disposal*: Inadequate management and treatment during wastewater transport and treatment or disposal can impact surface and groundwater resources.

These four stages occur in two interconnected environments: 1) the surface where spills during chemical mixing and wastewater management pose potential risks to surface waters and habitats, and 2) groundwaters. In the subsurface, water and chemicals can potentially leak along the well bore, propagating fractures, and existing pathways and fracture networks into shallower formations, including aquifers. Exhibit 4-5 illustrates these four stages in the use of water for hydraulic fracturing.

Exhibit 4-5. Water use in hydraulic fracturing operations



4.2.1 Chemical Mixing

Large quantities of fluids are essential to the drilling process. Drilling fluids circulate cuttings (rock chips produced during drilling, much like sawdust from drilling into wood) to clear the borehole as the drill advances, cool and lubricate the drill bit, stabilize the wellbore to prevent caving in, and control borehole fluid pressures. Drillers typically use lined surface pits or tanks to store water and drilling fluids (DOE, 2009). Shale gas drilling poses potential risks to water quality from spills or releases of chemicals and wastes resulting from tank ruptures, blowouts, equipment, or impoundment failures, overfills, vandalism, accidents, ground fires, operational errors, or stormwater runoff (GAO, 2012a; The Horinko Group, 2012).

EPA describes four key properties that fracturing fluids should possess:

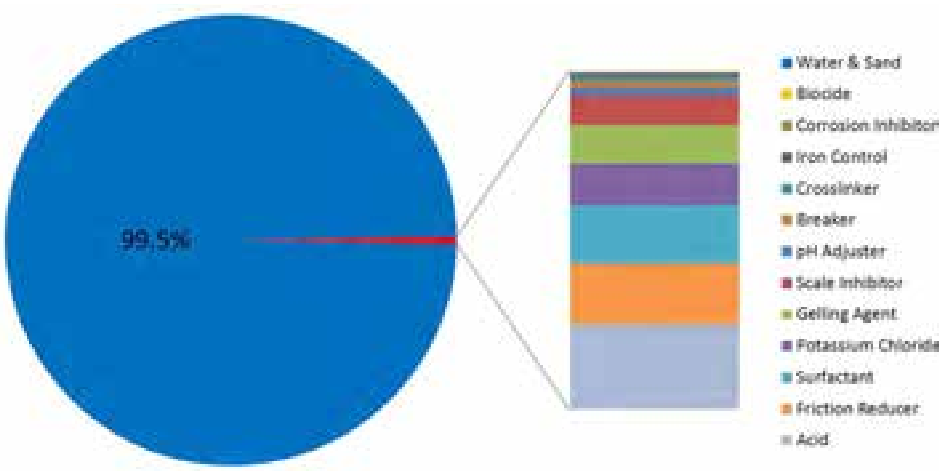
1. *Viscosity*: high enough to create fractures with adequate widths
2. *Penetration*: maximize the distance fluid travel to extend fracture lengths
3. *Transport*: ability to carry large amounts of proppant into the fractures
4. *Degradation*: minimize the amount of gelling agent to make degradation (or "breaking") easier and cheaper (2004)

Hydraulic fracturing can serve multiple purposes; most generally, it is used to increase the productivity of a well, either for injection (as in disposal wells) or extraction (or oil and gas production). In addition to increasing permeabilities and fluid flow rates, fracturing can increase the amount of contact between the well and the formation and the area of drainage within the formation and can be used to manage pressure differences between the well and the formation (EPA, 2004).

4.2.1.1 Shale Gas Drilling and Fracturing Fluids

As mentioned previously, water typically makes up more than 98 percent of the fracturing fluids used for hydraulic fracturing. In addition to water, fracturing fluid consists of a proprietary mix of chemicals and other fluids, with each serving a specific, engineered purpose. Additionally, more than 1 MM pounds of proppants may be used in hydraulic fracturing a well to prop the newly created fractures open and allow formation fluids to flow into the borehole. Proppants are compression-resistant particles, originally mainly fine-grained sand but now also include aluminum or ceramic beads, sintered bauxite, and other materials (KPMG, 2012). In a representative example from a Fayetteville well, water and sand made up more than 99 percent of the volume with various chemicals making up the rest (see Exhibit 4-6) (DOE, 2009).

Exhibit 4-6. Volumetric composition of a hydraulic fracturing fluid



Each of these chemical additives serves a specific purpose, from corrosion and scale inhibitors to friction reducers. The specific compounds used for each drilling operation vary depending on local geologic and hydrologic conditions, and according to different operators. Exhibit 4-7 describes the types of compounds added to fracturing fluids and their purposes (DOE, 2009; FracFocus, 2013).

Exhibit 4-7. Fracturing fluid additives, main compounds, and purposes

Additive	Compound(s)	Purpose	Percentage of Fluid (% of volume)	
			DOE (2009)	FracFocus (2013)
Dilute Acid	Hydrochloric or muriatic acid	Helps dissolve minerals and initiate cracks in the rock	0.123	0.07
Friction Reducer	Polyacrylamide or mineral oil	Minimizes friction between fluid and pipe	0.088	0.05
Surfactant	Isopropanol	Increases the viscosity of the fracture fluid	0.085	N/A
Potassium chloride		Creates a brine carrier fluid	0.060	N/A
Gelling Agent	Guar gum or hydroxyethyl cellulose	Thickens water to suspend sand	0.056	0.5
Scale Inhibitor	Ethylene glycol	Prevents scale deposits in the pipe	0.043	0.023
pH Adjusting Agent	Sodium or potassium bicarbonate	Maintains effectiveness of other components, such as crosslinkers	0.011	N/A
Breaker	Ammonium persulfate	Allows a delayed break down of the gel polymer chains	0.01	0.02
Crosslinker	Borate salts	Maintains fluid viscosity as temperature increases	0.007	0.032
Iron Control	Citric acid	Prevents precipitation of metal oxides	0.004	0.004
Corrosion Inhibitor	N,n-dimethyl formamide	Prevents the corrosion of the pipe	0.002	0.05
Biocide	Glutaraldehyde	Eliminates bacteria in the water that produce corrosive byproducts	0.001	0.001
Oxygen Scavenger	Ammonium bisulfate	Removes oxygen from the water to protect pipe from corrosion	N/A	N/A
Clay Control	Choline chloride, sodium chloride	Minimizes permeability impairment	N/A	0.034
Water and Proppant	Proppant: silica or quartz sand	Allows fractures to remain open so gas can escape	99.51	99.2

To provide the public information about chemicals used in hydraulic fracturing, the Ground Water Protection Council and Interstate Oil and Gas Compact Commission manage a national hydraulic fracturing chemical registry called FracFocus.[h] This site also offers general information on hydraulic fracturing, chemicals, their purposes, and groundwater protection measures. While it is not an official government information system, FracFocus is being used by states for official disclosure. Colorado, Oklahoma, Louisiana, Texas, North Dakota, Montana, Mississippi,

[h] Available at www.fracfocus.org

Utah, Ohio, and Pennsylvania use FracFocus (2013) to disclose chemical use. The FracFocus website reports the average hydraulic fracturing fluid composition for U.S. shale plays, based on August 2012 data. The relative proportions of some additives have changed since the DOE (2009) shale gas primer was published, but the types of chemicals and their purposes remain essentially the same.

4.2.1.2 CBM Drilling and Fracturing Fluids

CBM formations can be fractured with a variety of fluids, including gelled fluids, foamed gels, water with potassium chloride, and acids, or a combination of these fluids. Gellants (or thickeners) are added to water to increase viscosity; the selection of gellants is based on local formation conditions. Foamed gels, typically made by adding N_2 or CO_2 as the foamant, use the bubbles in the foam to carry proppant into the fractures. Some CBM wells need no proppants, and so water, sometimes pumped from the formation itself, can be used for fracturing. Acids are used to dissolve limestone formations that overlay or are interbedded with the coal beds to increase permeabilities. Similar to the fluids used in shale gas production, other fluids can be added to these fracturing fluids to increase the efficiency and productivity of CBM wells. These additives include breakers to decrease viscosities, biocides, fluid-loss additives, friction reducers, and acid corrosion inhibitors, plus proppants (EPA, 2004).

4.2.2 Well Injection

Underground migration of fluids, during and after hydraulic fracturing, poses a risk of contamination to groundwater quality by loss of drilling and fracturing fluids and migration of CH_4 or saline fluids from the target formation.

4.2.2.1 Loss of Drilling and Fracturing Fluids

The GAO (2012b) identified three primary pathways through which drilling and fracturing fluids can migrate through the subsurface and reach groundwater aquifers:

1. *Inadequate or Improper Casing and Cementing*: The well must be isolated with casing and cement to prevent gas or other fluids from contaminating aquifers. Pathways can be created by inadequate depth to casing, inadequate cement in the space around the casing, or cement that degrades under borehole conditions.
2. *Existing Fractures, Faults, and Abandoned Wells*: Drilling and fracturing can create connections with existing fractures or faults, or improperly plugged and abandoned wells, allowing gas and contaminants to migrate through the subsurface.
3. *Fracture Growth*: Fractures induced by hydraulic fracturing can propagate out of the production zone, allowing contaminants to reach groundwater in an aquifer.

Groundwater aquifers used as sources of drinking water typically occur at much shallower depths than the shale formations that produce natural gas. The primary barriers to subsurface contamination are proper siting, drilling, and completion of boreholes to ensure seals between the borehole and the rock outside the production zone, and the vertical separation between the geologic formations that produce shale gas and the shallower aquifers normally used as sources of drinking water.

Current well construction practices include multiple layers of protective steel casing and cement that protect freshwater aquifers and ensure that the producing zone is isolated from overlying formations. The casing is set while the well is being drilled and then, before drilling any deeper, the new casing is cemented to seal the gap between the casing and the formations being drilled through. Each string of casing then serves to protect the subsurface environment by separating the drilling fluids inside and formation fluids outside of the casing. Operators can check and repair the integrity of the casing and the cement bonding during and after drilling (DOE, 2009).

In addition to the engineered barriers in the casings and cements, the rock formations themselves act as natural barriers that contain natural gas and associated fluids in the target formation. Effective seals are what contain oil and gas and allow it to accumulate into economically extractable resources, just as is the case with aquifer formations that hold economic quantities of freshwater. In fact, the technology developments that have allowed extraction of natural gas from shale formations involve ways to release gas otherwise trapped in these formations for millions of years (DOE, 2009).

In some shale plays, the vertical separation between the top of the shale formation and the deepest part of the aquifer can be more than two miles, reducing the likelihood of interconnections through the subsurface. Exhibit 4-8 lists representative separation distances for some of the major shale plays (GAO, 2012a and DOE, 2009).

Exhibit 4-8. Vertical separation distances for groundwater over major shale plays

Shale Play	Depth to Base of Treatable Water (ft)	Separation Distance (ft)	Depth to Shale (ft)	Net Thickness of Shale (ft)
Barnett	1,200	5,300–7,300	6,500–8,500	100–600
Fayetteville	500	500–6,500	1,000–7,000	20–200
Haynesville	400	10,100–13,100	10,500–13,500	200–300
Marcellus	850	2,125–7,650	4,000–8,500	50–200
Woodford	400	5,600–10,600	6,000–11,000	120–220
Antrim	300	300–1,900	600–2,200	70–120
New Albany	400	100–1,600	500–2,000	50–100

In Chapter 1 – Background, Exhibit 1-1 illustrates the major components of the shale gas well construction process. Exhibit 4-9 illustrates the multiple barriers created by the combination of multiple sets of casing and cement.

Exhibit 4-9. Components of the well construction process

Unlike shale gas plays, CBM formations tend to be shallower, and the coal beds can lie within underground sources of drinking water (EPA, 2004). For the three most productive CBM basins, coal seams in the San Juan Basin are found at 600–3,500 feet below ground, Powder River Basin seams lie at 450–6,500 feet below ground, and Black Warrior Basin seams occur at 350–2,500 feet. Because they are shallower than other gas wells, CBM wells can sometimes be drilled with water well equipment rather than the larger and more complex equipment needed for conventional and shale gas wells (EPA, 2010).

Two types of well completions are used for CBM production, open-hole and cased. No lining material is installed in open-hole completions so that the gas can seep into the well bore and be brought to the surface. Cased completions are lined and then the casings are perforated in producing zones to allow the gas to flow into the well. Open-hole completions are used more often for CBM wells than conventional production, especially in the Powder River Basin (EPA, 2010).

In evaluating reports from citizens about water quality issues, EPA found no confirmed evidence that drinking water wells had been contaminated by hydraulic fracturing fluid injection in CBM wells (EPA, 2004). EPA (2010) noted that future CBM development may rely on deeper, thinner, tighter, and lower-rank coals, any of which would increase production costs, and that tighter coals could require hydraulic fracturing to produce gas economically. However, in terms of environmental impacts, EPA subsequently focused on the discharge of produced water (EPA, 2010).

4.2.2.2 *Migration of CH_4 and Formation Fluids*

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A December 2008 explosion in a house in Geauga County, Ohio, was investigated by the Ohio Department of Natural Resources (ODNR) (2008). Local responders quickly recognized that natural gas was leaking into houses through water wells. The gas-bearing formation in the area is the Silurian "Clinton" sandstone, the local term for a sequence of inter-bedded sandstones, siltstones, and shales. The ODNR determined that deep, high-pressure natural gas had over-pressurized the annulus of the English No. 1 Well, allowing gas to migrate from the well annulus into natural fractures in the bedrock below the cemented surface casing. This gas then migrated upward through fractures into the overlying aquifers and escaped from the aquifer through local water wells. The ODNR identified three primary contributing factors: inadequate cement of the production casing, hydraulic fracturing of the well with the inadequate cement, and shutting-in the well for 31 days after the fracturing, which allowed pressure to build. The ODNR determined that 22 domestic and one public water supply had been contaminated by natural gas charging from the English No. 1 Well. The data indicated that groundwater had not been contaminated by brine, crude oil, or fracturing fluids.

In January 2008, the ODNR announced implementation of new permit conditions for northeastern Ohio. CH_4 and formation fluids can migrate naturally within the subsurface, even without disturbance by drilling or hydraulic fracturing. Warner et al. (2012) present evidence that pathways unrelated to drilling or hydraulic fracturing can exist between deep formations and overlying aquifers. Geochemical data and isotopic ratios indicate that mixing between shallow groundwater and brines from deeper formations can cause salinization of groundwater along naturally occurring pathways.

In the Fayetteville region, Kresse et al. (2012) sampled and analyzed 127 domestic water wells to describe the general quality and geochemistry, and to investigate the potential impacts of gas-production on shallow groundwater in the area. Water-quality analyses from this study were compared to pre-development shallow groundwater quality samples. Among the results, the authors found higher chloride, major ion, and trace metal concentrations in the pre-development samples. CH_4 was also detected in a subset of the post-development samples but based on carbon isotope ratios the authors concluded that CH4 had biogenic origins. The groundwater-quality data collected for this study indicated that groundwater chemistry in the shallow aquifer system in the study area, including CH_4, was a result of natural processes.

CH_4 has also been found in water wells in Pennsylvania pre-dating the advent of Marcellus Shale gas development. Breen et al. (2007) investigated occurrences of natural gas in wellwater in Pennsylvania. Gas occurrence in groundwater and accumulation in homes had become a safety concern; the investigators concluded that the weight of evidence pointed to gas from local underground storage fields as the likely origin.

In 2010 and 2011, the Center for Rural Pennsylvania analyzed water samples from private water wells located within 5,000 feet of Marcellus Shale gas wells (Boyer et al., 2012). Water from approximately 40 percent of these wells failed at least one SDWA standard, typically for coliform bacteria, turbidity, and manganese, before gas well drilling. The results also showed dissolved CH_4 in about 20 percent of water wells prior to the development of natural gas wells. Post-drilling analysis showed no significant increases in pollutants from drilling fluids and no significant increases in CH_4. There were outlier samples that exhibited high concentrations of total dissolved solids (TDS) and chloride after the nearby development of natural gas wells; Boyer et al. (2012) found no evidence linking these increased TDS and chloride concentrations to natural gas well development.

Duke University researchers studied shale gas drilling and hydraulic fracturing, and the potential effects on shallow groundwater systems near the Marcellus Shale in Pennsylvania and the Utica Shale in New York (Osborne et al., 2011). CH_4 concentrations were detected generally in 51 drinking water wells, but concentrations were higher closer to shale gas wells. A source of the contamination could not be determined, and no evidence of fracturing fluids was found in any of the samples. Isotopic data for CH_4 detected in shallow groundwater were consistent with deeper sources such as the Marcellus and Utica and matched the natural gas geochemistry from nearby gas wells. Lower-concentration samples from non-active sites had isotopic signatures reflecting a more biogenic or mixed biogenic-thermogenic source. The authors found no evidence of contamination of drinking water samples with deep saline brines or fracturing fluids.

Osborne et al. (2011) describe three possible sources for the CH_4 they detected. The first is physical displacement of gas-rich solutions from shale formations, which is unlikely due to the 1–2 km of strata above the shale. The second is leakage along gas well casings, with CH_4 passing laterally and vertically into existing fracture systems. The third source is the formation of new fractures, or the enlargement of existing ones, due to hydraulic fracturing, thereby increasing the interconnectivity of the fracture system. They concluded that the higher concentrations measured in shallow groundwater from active drilling areas could result from migration from a deep CH_4 source associated with drilling and hydraulic fracturing activities. In contrast, the lower-level concentrations in groundwater aquifers observed in the non-active areas are likely a natural phenomenon. More recently, Jackson et al. (2013) examined concentrations of natural gas and isotopic ratios in drinking water wells in northeastern Pennsylvania and found CH_4 in 82 percent of 141 wells. Concentrations averaged six times higher in wells less than 1 km from natural gas wells. These authors concluded that isotopic signatures, hydrocarbon ratios, and helium/CH_4 ratios indicate a Marcellus-like source in some cases, suggesting that some water wells within 1 km of gas wells are contaminated by stray gases.

Molofsky et al. (2013) tested 1,701 water wells in northeastern Pennsylvania and found that CH_4 was ubiquitous in local groundwater. Higher concentrations were found in valleys than in upland areas and particular water chemistries, which correlates more with topography and hydrogeology than Marcellus Shale gas extraction. The authors concluded that CH_4

concentrations in water wells in this area could be explained without migration of Marcellus shale gas through fractures.

Vengosh et al. (2013) review results from Osborne et al. (2011) and Molofsky et al. (2011) regarding the sources of possible CH_4 contamination in drinking water wells in the Marcellus. Osborne et al. (2011) found that elevated levels of CH_4 correlated in water wells within 1 km of natural gas wells. Isotopic and geochemical signatures indicated that high levels of CH_4 contamination in the closer wells had thermogenic sources rather than the mixed and biogenic sources in wells farther away. New noble gas data corroborate the conclusion that CH_4 in the closer wells had a thermogenic origin. Vengosh et al. (2013) report that the most likely pathway for the CH_4 was leaking through inadequate cement on casing, or through well annulus from intermediate formations.

4.2.3 Flowback and Produced Water

At least 56 MM bbl (2.4 B gal) of water is produced per-day nationwide as a byproduct of drilling oil and gas wells (GAO, 2012b). The five states with the greatest produced water volumes in 2007 were Texas, California, Wyoming, Oklahoma, and Kansas. Texas alone accounted for more than 7.3 B bbl, contributing to 35 percent of the total produced water by volume. Produced water from unconventional natural gas production is not necessarily a major contributor to the total volumes of nationally produced water from oil and gas production. Of the top 10 states for produced water, only five have major unconventional gas play (Clark and Veil, 2009). However, the volumes of produced water from unconventional gas production can present local and regional challenges.

4.2.3.1 Flowback Water

In the days and weeks following the injection of the 2–6 MM gal of water, chemicals, and proppants used to hydraulically fracture a shale gas well, a fraction of this water is recovered as flowback water, while the remainder is temporarily lost into the formation. Estimates vary on what fraction of injected fluids return to the surface. The GAO (2012a) reports that 30–70 percent of the original fluid injected returns to the surface; IHS (2012) puts the figure at 20–80 percent; the CRS (2009) reports that this figure can range 60–80 percent.

Gregory et al. (2011) tabulates a typical range of concentrations for some of the common constituents of flowback water from the Marcellus Shale (Exhibit 4-10). The "low" concentrations were measured in early flowback from one well; "medium" concentrations were from late flowback from the same well; the "high" concentrations were measured in several wells with similar TDS concentrations.

Exhibit 4-10. Typical concentrations for common constituents in flowback water

Constituent	Low (mg/L)	Medium (mg/L)	High (mg/L)
TDS	66,000	150,000	261,000
TSS	27	380	3,200
Hardness (as calcium carbonate)	9,100	29,000	55,000
Alkalinity (calcium carbonate)	200	200	1,100
Chloride	32,000	76,000	148,000
Sulfate	ND	7	500
Sodium	18,000	33,000	44,000
Calcium (total)	3,000	9,800	31,000
Strontium (total)	1,400	2,100	6,800
Barium (total)	2,300	3,300	4,700
Bromide	720	1,200	1,600
Iron (total)	25	48	55
Manganese (total)	3	7	7
Oil and grease	10	18	260
Total Radioactivity	ND	ND	ND

ND = Not detected

The drillers may temporarily retain the flowback and brine in lined retention ponds before reuse or disposal; the pits must be reclaimed when operations end at that site. The well operator must then separate, treat, and dispose of the natural brine co-produced with the gas.

Flowback water can make treatment more difficult because it contains extremely high amounts of TDS. The longer the fracturing fluid remains below ground in contact with the shale, the higher the TDS, metals, and naturally occurring radioactivity it can pick up from the formation (Abdalla et al., 2012). The additives for hydraulic fracturing in a 3 MM gal fracturing job would yield about 15,000 gal of chemicals in the waste or about 0.5 percent of the total volume (CRS, 2009).

4.2.3.2 Produced Water

Once the well begins to produce natural gas, it also yields formation fluids called produced water (IHS, 2012). Because produced water has been held in hydrocarbon-bearing formations, the fluids found in oil and gas bearing formations typically include a variety of hydrocarbons and water or saltwater brines. The properties of produced water vary considerably depending on the geologic formation, the location of the field, and the types of hydrocarbons being produced. Produced water volumes and chemical properties can also vary throughout the producing lifetime of a formation (Clark and Veil, 2009).

The quality of produced water is typically poor, and generally cannot be used for other purposes without treatment. The GAO (2012b) described the range of possible contaminants that includes, but is not limited to the following:

- *Salts*: chlorides, bromides, and sulfides of calcium, magnesium, and sodium
- *Metals*: barium, manganese, iron, and strontium
- *Organics*: oil, grease, and dissolved organics
- *Naturally Occurring Radioactive Materials*: including radium and radon
- *Production Chemicals*: including those used for hydraulic fracturing

CBM wells produce more water than other forms of unconventional natural gas wells. Water pressure in the coal seam helps keep the gas attached to the coal; lowering the pressure by pumping out water helps release the gas (Guerra et al., 2011). Water production from CBM wells normally starts at high volumes, but then falls as the coal seam is depressurized. Produced water from CBM wells varies in quality from very good (meeting state and federal drinking water standards) to very high in TDS with concentrations up to 180,000 parts per million, which is not suitable for reuse (ALL Consulting, 2003). Exhibit 4-11 tabulates representative produced water quality data for the San Juan Basin and Powder River Basin, which together represent nearly 70 percent of CBM production.

Exhibit 4-11. Chemical constituents in CBM produced waters

Constituent	San Juan Basin		Powder River Basin	
	Minimum (mg/L)	Maximum (mg/L)	Minimum (mg/L)	Maximum (mg/L)
TDS	180	171,000	244	8,000
Barium	0.7	63	0.06	2
Calcium	0	228	5	200
Chloride	0	2,350	3	119
Iron	0	228	0.03	11
Magnesium	0	90	1	52
Potassium	0.6	770	2	20
Sodium	19	7,130	89	800
Sulfate	0	2,300	0.01	1,170

The treatment of CBM produced water is discussed below in Section 0 (in particular, Section 4.2.4.4).

4.2.4 Wastewater Management and Disposal

The oil and gas industry applies a three-tiered approach to the management of produced water that follows a hierarchical pollution prevention approach (NPC, 2011; Veil, 2011):

- *Minimization*: mechanical and chemical alternatives to water use

- *Recycle/Re-use*: re-injection for enhanced recovery or continued hydraulic fracturing, re-use for agriculture and industry, and treatment for drinking water
- *Disposal*: underground injection, evaporation, or surface water discharge

How operators manage, treat, and dispose of produced and flowback water is mainly an economic decision made within the limits of the applicable federal and state regulations. For example, underground injection is most often the least-cost option, ranging from $0.07–1.60/bbl. Trucking costs for an injection well can significantly increase the total costs. In Texas, trucking costs can range $0.50–1.00/bbl; in Pennsylvania they can range from $4.00–8.00/bbl. Water treatment can cost between $6.35–8.50/bbl, and advanced treatment by reverse osmosis and ion exchange can cost an additional $0.20–0.60/bbl (GAO, 2012b).

The GAO (2012b) reports that other factors that influence water management options:

- *Geology*: availability of injection wells and their distances from producing wells
- *Climate*: arid climates are more favorable for evaporation from surface impoundments
- *Regulations*: federal and state regulations control the use of management methods
- *Risk Management*: legal liabilities from surface discharges and impoundments

Exhibit 4-12 outlines the main water management technologies used by each shale play (DOE, 2009).

Exhibit 4-12. Produced water management by shale gas basin

Shale Gas Basin	Water Management Technology	Availability	Comments
Barnett	Class II injection wells	Commercial & non-commercial	Disposal into Barnett and underlying Ellenberger Group
	Recycling	On-site treatment & recycling	Reuse in subsequent fracturing
Fayetteville	Class II injection wells	Non-commercial	Disposal into two injection wells owned by a producing company
	Recycling	On-site recycling	Reuse in subsequent fracturing
Haynesville	Class II injection wells	Commercial & non-commercial	N/A
Marcellus	Class II injection wells	Commercial & non-commercial	Limited use of Class II injection wells
	Treatment and discharge	Municipal and commercial treatment facilities	Primarily in Pennsylvania
	Recycling	On-site recycling	Reuse in subsequent fracturing
Woodford	Class II injection wells	Commercial	Disposal into multiple confining formations
	Land application	N/A	Permit required through OK Corporation Commission

Shale Gas Basin	Water Management Technology	Availability	Comments
	Recycling	Non-commercial	Water recycling and storage at central location
Antrim	Class II injection wells	Commercial & non-commercial	N/A
New Albany	Class II injection wells	Commercial & non-commercial	N/A

Different management methods invoke different sets of statutory and regulatory controls. For example, underground injection is regulated by EPA and the states under the SDWA, while discharges of waters are regulated under the Clean Water Act and the National Pollutions Discharge Elimination Systems. Other management practices can be regulated by state authorities (GAO, 2012b). The sections below summarize each of the common management methods.

4.2.4.1 Minimization

Options for minimizing water use available to unconventional natural gas producers mainly involve mechanical and chemical alternatives that reduce the amount of water needed for drilling and hydraulic fracturing. Down-hole mechanical blocking devices such as packers and plugs can cut the amount of water needed in the borehole during development. Other materials, like CO_2 or N_2 can be used in place of water, as can gelled fluids. However, gelled fluids can damage the formation and increase the amounts and types of chemicals used (NPC, 2011). In places like Wyoming where infrastructure, including pipelines are readily available, CO_2 has already been used for fracturing in place of water. However, substituting CO_2 for water on a larger scale (e.g., across the United States) would require large investments in infrastructure to deliver the CO_2 to drilling and fracturing sites (MIT, 2013).

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4.2.4.2 Recycle and Reuse

Shale gas producers have begun reusing produced water for hydraulic fracturing. Water is typically treated first, and then mixed with freshwater if salt concentrations remain high. For reuse to become widespread, among shale gas operators, new, low-cost treatment technologies will be needed. Re-use has become more common among shale gas producers in Pennsylvania, in part due to a change in the state's surface water discharge standards that made treatment and discharge comparatively more expensive (GAO, 2012b).

The feasibility of using produced and flowback water for shale gas production depends on the volume and quality of the re-used water. Operators benefit from larger volumes of water that stabilize the logistics of collecting, storing, and transporting the water, keeping tanks and pits in use and trucks moving. Water quality is important for reuse, particularly the TDS, mainly the salt content, and total suspended solids (TSS), or the amount of fine-grained particulate matter in the water, to control the drilling fluid chemistry and remove some of the contaminants that can return to the surface with the produced water.

Accenture (2012) divides water treatment technologies into two categories, the first for removing inorganic materials, primarily salts, and the second for organic materials, including oil and grease. The unconventional gas industry has concentrated on developing technologies to deal with the inorganic materials given the high TDS in flowback water from shale gas development. Accenture (2012) describes four types of treatment technologies available to shale gas operators:

1. *Filtration* removes suspended solids with anything from simple household water filters to more complex and efficient designs. Shale gas operators use filters with pore sizes of 0.04–3 microns.
2. *Chemical Precipitation* removes scale-forming elements like calcium, magnesium, barium, strontium, iron, manganese, and other metals. By adding chemicals and adjusting pH values, these constituents precipitate out of solution and settle out where they can be collected as sludge for disposal.
3. *Thermal-Based Technologies* remove salts from waters with very high TDS levels. By heating the water to almost the boiling point, the water vapor can be collected as distilled water or evaporated to the atmosphere. The residual solids collected as concentrated brine or crystalline salt.
4. *Membrane Filtration Technologies* have limited use in shale gas production as they are ineffective at filtering TDS concentrations greater than 35,000–45,000 parts per million. Reverse osmosis is a common membrane filtration technology.

Produced water from the Barnett is generally high in TDS, but low in TSS and moderate scaling tendency. The preferred management method is disposal by underground injection. The large volumes of produced water and the availability of Class II disposal injection wells in the Barnett region limit the reuse of water. One operator reports treating and reusing about 6 percent of the total water needed for drilling and fracturing in the Barnett (Mantell, 2010).

Fayetteville Shale produced water is generally of excellent quality for reuse, having very low TDS, low TSS, and low scaling tendency. Since TSS levels are low, very limited treatment (filtration) is needed prior to reuse. The volume of water generated is typically sufficient to justify reuse (Mantell, 2010). One operator is currently meeting approximately 6 percent of its drilling and fracturing needs in the Fayetteville with produced water reuse and has a goal of 20 percent reuse in the play (Veil, 2011). As with the Barnett, logistics and economics are the primary limiting factors that prevent higher levels of reuse in the Fayetteville (Mantell, 2010).

The Haynesville Shale produces a smaller volume of produced water initially, relative to other major plays, but it is of very poor quality. TDS levels are immediately high, TSS is high, and the produced water has high scaling tendency. The quality and volume factors combined with an adequate underground injections infrastructure make produced water reuse in the Haynesville challenging. Low produced water volumes, poor produced water quality and the associated economics have prevented successful reuse of produced water to-date in the Haynesville (Mantell, 2010).

The Marcellus Shale is ideal in terms of produced water generation in that it produces significant volumes of water during the first few weeks and then water production typically declines quickly. Marcellus produced water is good quality with moderate to high TDS, low TSS, and moderate scaling tendency. Operators manage TDS by blending previously produced water with freshwater and the TSS is managed with filtration systems. Scaling is managed through precise monitoring and testing to ensure the compatibility of the blended produced and freshwater (Mantell, 2010). The proportion of flowback water now reused in Pennsylvania is estimated to be as high as 75 percent (Abdala et al., 2012).

Veil (2010) examined the flowback and water management technologies and methods used today that are likely to continue to be used in the Marcellus region. He concluded that the region has sufficient water supplies and coordination with authorities like the Susquehanna River Basin Commission and the Delaware River Basin Commission has not become an obstacle. Marcellus operators have had some success reusing water from previous hydraulic fracturing with lower-TDS freshwaters, which would cut costs and reduce the volumes of freshwater needed.

Treatment of shale gas wastewater became an issue in Pennsylvania in 2011, where there are limited wastewater disposal options. Operators were sending wastewater to municipal wastewater treatment plants, which then treated the water and discharged it to rivers that supply drinking water populations across Pennsylvania and Maryland. The media reported concerns that these treatment plants were neither designed nor capable of treating drilling wastewaters. In March 2011, EPA (2011) wrote to environmental officials in Pennsylvania noting “variable and sometimes high concentrations of materials that may present a threat to human health and aquatic environment, including radionuclides, organic chemicals, metals and total dissolved solids” were present in the wastewater, and urged increased water quality monitoring, particularly for radionuclides. Subsequent concerns about elevated bromide levels in state waterways prompted Pennsylvania regulators to request that operators stop sending their wastewaters to municipal treatment plants that may not be prepared to treat it. According to the Marcellus Shale Coalition, Marcellus operators complied with the state’s request within two days (Williams, 2012).

4.2.4.3 Disposal

The preferred disposal method for water in the oil and gas industry is largely underground injection. In 2007, more than 98 percent of produced water from onshore wells was injected underground (Clark and Veil, 2009). EPA and states regulate this practice under the SDWA and UIC (EPA, 2013). Among the six classes of injection wells recognized by EPA, oil and gas-related wells form Class II, which includes wells for enhanced recovery, disposal, and hydrocarbon storage.

Class II injection wells are specifically designed and constructed to inject fluids into permitted zones and prevent migration of injected fluids into underground sources of drinking water. Most produced water generated onshore is used to maintain reservoir pressures and drive oil toward producing wells for enhanced oil recovery (Clark and Veil, 2009). Produced water does not need treatment before injection, but operating requirements to prevent plugging may cause water to be treated to control solids and dissolved oil, inhibit corrosion and chemical reactions, and retard microbial growth. Settling tanks, chemical additives, and filtration may also be used (GAO, 2012b).

In the Marcellus, only about 5 percent of the water used is disposed of without treatment via underground injection (Abdala et al., 2012). The current disposal practice for Marcellus Shale liquids in Pennsylvania requires processing them through wastewater treatment plants, but the effectiveness of standard wastewater treatments on these fluids is not well understood. In particular, salts and other dissolved solids in brines are not usually removed successfully by wastewater treatment, and reports of high salinity in some Appalachian rivers may be associated with the disposal of Marcellus Shale brines. Concerns in Appalachian States about the possible contamination of drinking water supply aquifers have limited the practice of re-injecting Marcellus fluids (Soeder and Kappel, 2009).

4.2.4.4 Discharge to Surface Water or Evaporation

A very small fraction, less than 1 percent, of onshore produced water is discharged to surface water bodies, generally in the western states when the TDS content is low. Treatment for surface discharge includes settling and filtration of solids, and salt removal with chemical additives. Other methods used to remove salts and other contaminants include thermal distillation, reverse osmosis (filtration), and ion exchange (only at low concentrations) (GAO, 2012b).

Surface water discharge for unconventional natural gas production is associated mainly with water produced from CBM extraction. EPA (2010) estimated that more than 47 B gal of water were produced from coal seams in 2008 and about 45 percent, or about 22 B gal, was discharged to surface waters. Currently, allowing surface water discharges is made by either state agencies or EPA regional offices, depending on the state's permitting authority (Clark and Veil, 2009). More commonly, for example, in the Powder River Basin, produced water is held in ponds or pits for evaporation. Some of this water is used for irrigation when it does not require treatment to meet water quality standards (GAO, 2012b).

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5 Induced Seismicity

Induced seismicity is ground motion (earthquakes) caused by human activities. Earthquakes have been detected in association with oil and gas production, underground injection of wastewaters, and with hydraulic fracturing (Rubinstein and Mahani, 2015). Hydraulic fracturing involves injecting large volumes of fluids into the ground. In contrast to hydraulic fracturing, wastewater from oil and gas production, including shale gas production, is typically disposed of by being injected at relatively low pressures into extensive formations that are specifically targeted for their porosities and permeabilities to accept large volumes of fluid. Case studies from several states indicate that deep underground fluid injection can, under certain circumstances, induce seismic activity (Horton, 2012; Frolich, 2012; ODNR, 2012; Keranen et al., 2013; Hayes, 2012).

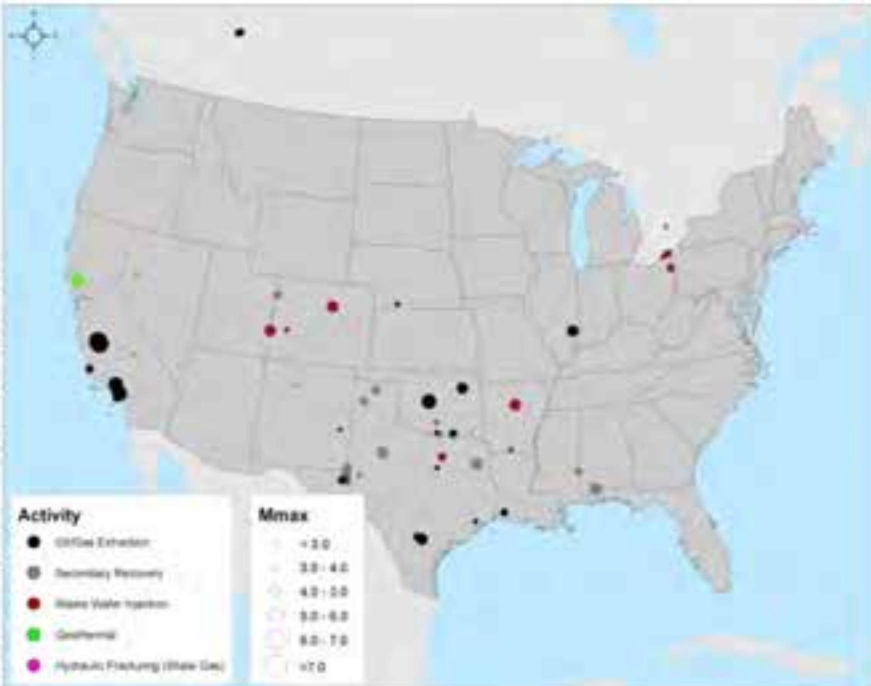
5.1 Induced Seismicity and Energy Technologies

The term seismic activity is used to describe the vibration of mechanical energy passing through the earth, much like sound waves vibrate through the atmosphere. More than 1.4 MM earthquakes greater than magnitude 2.0 (Richter Scale) are measured world-wide each year. Most earthquakes occur naturally in response to sudden slips and shifts of large masses of rock along geologic faults. Earthquakes with magnitudes of 2.0 or less generally cannot be felt at the surface by people. Magnitudes greater than 3.0 tend to produce noticeable shaking and magnitudes greater than 5.0 can potentially cause structural damage to buildings and property.

Commented [HSAJ61]: Add a citation

The NRC (2012) describes seismic events caused by or likely related to energy development in at least 13 states involving oil and gas extraction, secondary recovery, wastewater injection, and geothermal and hydraulic fracturing for shale gas. Exhibit 5-1 shows sites in the United States and Canada with a history of incidents of induced seismicity caused by or related to energy development operations (NRC, 2012). The reporting of small events is limited by the availability of sufficiently sensitive seismic monitoring networks. However, the NRC notes that proving human activity caused by a particular event can be difficult because such conclusions depend on local data, records of prior seismicity, and scientific literature.

Exhibit 5-1. Locations of induced seismicity associated with energy technologies



The GWPC (2013) provides an updated overview of induced seismicity in their white paper titled "Assessing and Managing Risk of Induced Seismicity by Injection," which summarizes a 2013 special technology transfer session held in Sarasota, Florida. The session focused on the risks of induced seismicity and reviewed the recent NRC (2012) case study examples of induced seismicity. The major issues and findings discussed in paper included the following (GWPC, 2013):

Commented [HSAJ62]: Was this session at a specific conference? If so list.

> In nearly all cases, the potential for felt seismicity from hydraulic fracturing is very low, although a few cases have been observed where unique conditions were present. However, these have not led to any significant surface damage. The NAS report [NRC, 2012] concluded that hydraulic fracturing does not pose a high risk for induced seismicity.
>
> Tens of thousands of disposal wells are employed each day to inject produced water and other wastewaters into formations that are not hydrocarbon bearing. Most of these injections pose a low risk of induced seismicity but given the ongoing injection and cumulative formation pressure build up over time, there is some potential that disposal wells can contribute to induced seismicity. Most wells are completed in areas and geological formations that are not likely to lead to induced seismicity, but several well-documented examples are described in this white paper where seismic activity was

linked to disposal wells (e.g., Ohio, Arkansas, Oklahoma, and Texas). These are typically due to some geological anomalies or faults in those locations.

The GAO (2012) concluded that the energy released by hydraulic fracturing does not produce enough ground motion to be felt at the surface. However, disposal of waste fluids through underground injection (see also Chapter 4 – Water Use and Quality), which is commonly used throughout the oil and gas industry, including unconventional natural gas production, has, in some instances, been associated with perceptible earthquakes. The existing research does not establish a direct link between hydraulic fracturing and increased seismic activity, but to the extent that increased hydraulic fracturing increases the amount of water disposed of through underground injection, it could contribute to increased seismicity.

5.2 Hydraulic Fracturing for Unconventional Gas Production

Thompson (2011) outlined four differences between hydraulic fracturing and other types of potential causes of induced seismicity:

Commented [HSAJ63]: This doesn't seem to align with the four statements below. It seems as though Thompson 2011 outlines reasons hydraulic fracturing is not linked to induced seismicity.

1. *Different Type of Stress Release* – Hydraulic fracturing creates small fractures through tensile (extending) stresses where fractures spread as their walls are stretched apart whereas induced seismicity causes shear stresses that cause movement along faults.
2. *Limited Distances from the Wellbore* – Operators avoid creating fractures that propagate adjacent formations, which would waste fluids and energy outside the target formation and potentially allow gas to escape. Typically, shale gas fracturing penetrates 15 feet into the formation from the borehole and fracturing fluids on the order of 100 feet from the hole.
3. *Limited Volume of Fluid* – The amount of fluid used for hydraulic fracturing tends to be only what is needed to stimulate production.
4. *Limited Period of Time* – Hydraulic fracturing is normally completed within a period of hours or days. The operator's objective is to drill and fracture the well as efficiently as possible and pivot well operations to extracting natural gas as quickly as possible.

The seismic behavior caused by hydraulic fracturing shale gas wells is recorded and understood through microseismic monitoring. During hydraulic fracturing, very small earthquakes, or microseismic events, are created by the high-pressure injection of fluids into a target formation. The increased pore pressure causes small natural fractures in the formation to slip, causing "microearthquakes" that are measured and recorded with sensitive sensing equipment and processing algorithms. The location and magnitude of microseismicity is used by oil and gas operators to help identify the orientation and spacing of the hydraulic fractures in the formation, in addition to helping guide horizontal well directions and well spacing, and in planning subsequent fracturing treatments (Warpinski et al., 2012; NRC, 2012).

Warpinski et al. (2012) reviewed thousands of fracture treatments in six major shale basins in North America and found that the seismicity from hydraulic fracturing is small and does not create problems under normal circumstances. At least 12 incidents of induced seismicity associated with shale gas production and hydraulic fracturing have been documented worldwide, and six of these were in the United States. The other incidents occurred in the Horn River Basin in British Columbia, Canada; Blackpool, Lancashire, United Kingdom; and South Sichuan Basin, China (Schultz et al., 2020).

The first incident in the United States occurred in January 2011, when the Oklahoma Geological Survey (OGS) responded to a resident of Garvin County, in south-central Oklahoma, who reported feeling several earthquakes and observed that hydraulic fracturing operations were active nearby. The OGS found that there had been nearly 50 earthquakes ranging from 1.0–2.8 in magnitude and that 43 of the quakes were large enough to be located. The majority of the earthquakes seem to have happened within about 3.5 km of a shale gas well and had started about seven hours after the first well was hydraulically fractured. The correlation in space and time with the hydraulic fracturing suggested to Holland "that there is a possibility these earthquakes were induced by hydraulic fracturing. However, the uncertainties in the data make it impossible to say with a high degree of uncertainty whether these earthquakes were triggered by natural means or by the nearby hydraulic-fracturing operation" (Holland, 2011).

Davies et al*.* (in press) proposed three mechanisms by which the increased fluid pressure in a fault zone of hydraulic fracturing could trigger seismic events. First, fracturing or pore fluids could enter a fault. Second, with a direct connection between the fault and the fractures, a pulse of fluid pressure could be pushed to the fault. Third, fracturing could increase fluid pressure in the fault. The fluids or fluid pressure could follow three types of pathways: directly from the borehole, through newly created fractures, or through existing fractures or faults. Thus, a borehole could intersect the fault or be some distance from it. Theoretically, these mechanisms and pathways could produce the three documented examples of seismicity "probably induced by hydraulic fracturing" (Davies et al*.*, in press).

The Energy institute at The University of Texas at Austin funded an initiative to promote fact-based shale gas policies and regulations (Groat and Grimshaw, 2012). Their report focused on three of the major shale gas plays: Barnett, Haynesville, and Marcellus. Based on their review of the published literature, they found a broad consensus and drew five conclusions related to hydraulic fracturing and induced seismicity (Groat and Grimshaw, 2012):

1. The amount of fluid pumped during the hydraulic fracturing process is of orders of magnitude less than that required to propagate fractures upward to freshwater aquifers.
2. Tensile fractures created by hydraulic fracturing will have a very short life of enhanced permeability if they are not propped open by injected proppant particles.
3. Gas production will lower pressure in the fractured reservoir and drive fluid flow in and down, even after production has ceased.
4. Many of the fracturing fluid chemicals will rapidly dissipate during fracturing by reaction with the fractured rock surface, and some chemicals will be adsorbed on organic components and clay minerals.

5. After fracturing, any residual, depleted, fracturing fluid would mix with formation brines (as is seen in changes over time in the flowback water) and upward migration will essentially be impossible without very high driving pressures that do not exist.

The NRC examined the scale, scope, and consequences of seismicity induced during fluid injection and withdrawal related to energy technologies, including shale gas recovery, and concluded that, "the process of hydraulic fracturing a well as presently implemented for shale gas recovery does not pose a high risk for inducing felt seismic events" (NRC, 2012). The NRC (2012) noted that the very low number of felt events compared to the large number of hydraulically fractured shale gas wells is likely due to the short durations for injecting fluids, the limited volumes of fluid used, and the small spatial area affected by hydraulic fracturing.

5.3 Underground Injection of Liquid Wastes

In contrast to hydraulic fracturing for shale gas production, wastewater from oil and gas production, including shale gas production, is typically disposed by injecting it at relatively low pressures into extensive formations that are specifically targeted for their porosities and permeabilities to accept large volumes of fluid. Many of the well-documented instances of induced seismicity associated with fluid injection involve large amounts of fluids injected over long periods (NRC, 2012).

Underground injection of fluids is a common practice in the United States. The USGS (Nicholson and Wesson, 1990) lists a variety of examples of deep well injection operations, including wastewaters, solution mining, geothermal energy extraction, enhanced hydrocarbon recovery, and the underground storage of natural gas. EPA (2013) UIC regulates the construction, operation, permitting, and closure of injection wells that place fluids underground for storage or disposal. EPA and 39 states regulate more than 150,000 Class II injection wells for disposal of oil and gas wastewaters. The increase in hydraulic fracturing for shale gas production increased public awareness of induced seismicity from underground injection of fluids, so EPA (2013) added injection-induced seismicity as a research focus of its National Technical Workgroup.

Horton (2012) describes an increase in seismic activity in northcentral Arkansas following the installation of eight wells for the disposal of hydraulic fracturing wastewater from the Fayetteville Shale. While the area is prone to natural earthquake activity, the rate of 2.5 magnitude and greater earthquakes increased after the first disposal well started operations in April 2009. While there was one earthquake in 2007 and two in 2008, the number jumped to 10 in 2009, 54 in 2010, and 157 in 2011. Some 98 percent of the recent earthquakes happened within 6 km of one of three of the eight disposal wells. Horton concludes that this "close spatial and temporal correlation supports the hypothesis that the recent increase in earthquake activity is caused by fluid injection at the waste disposal wells" (Horton, 2012).

Frolich (2012) analyzed data from 67 earthquakes with 1.5 magnitude and greater in the Barnett Shale region that occurred between November 2009 and September 2011. He found that the 24 events with the most reliably identified epicenters were in eight groups within 3.2 km of one or more injection wells. All wells nearest the earthquake groups had injection rates greater than 150,000 bbl/month; however, not all wells with these injection rates were accompanied by earthquakes. Frolich (2012) hypothesizes that injection triggers earthquakes only if injected fluids relieve friction on a suitably oriented fault that is already under regional tectonic stress.

Between March 2011 and March 2012, the Ohio Department of Natural Resources (ODNR) recorded 12 low-magnitude seismic events ranging in magnitude from 2.1 to 4.0. Between the establishment of the ODNR "OhioSeis" seismic network in 1999 and 2011, no earthquake activity was recorded in the Youngstown area. The ODNR (2012) did note three earthquakes recorded in the area between 1986 and 2000 with magnitudes of 3.0–5.2, but the 2011–2012 events all occurred within a mile of the Northstar 1 deep injection well, which began operations in December 2010.

Approximately 35 separate inspections of the well in 2011 all concluded that the well was operating within its permitted injection pressure and volume; tests showed that the injections were within the permitted depth intervals, albeit with inconclusive results regarding the fluid volume reaching the bottom of the well at 9,184 feet. In late 2011, additional seismic monitoring equipment deployed in the area measured a 2.7 magnitude earthquake at 2,454 feet below the injection well. The ODNR (2012) determined that a "number of coincidental circumstances appear to make a compelling argument for the recent Youngstown-area seismic events to have been induced." These circumstances 89include the spatial proximity of the seismicity to the well and the temporal proximity to the start of injection, as well as evidence of higher-permeability zones in geophysical well logs.

The ODNR (2012) outlined circumstances that must be met for an injection well to induce seismicity:

- A fault must exist in the underlying basement rock
- The fault must be in a near-failure state of stress
- An injection well must be drilled deep and near enough to the fault to communicate hydraulically with the fault
- The operator must inject enough fluid at high enough pressures for an adequate amount of time to cause movement (failure) along the fault

The well was shut down on December 30, 2011. On December 31, a 4.0 magnitude earthquake in the Youngstown area led the State of Ohio to declare a moratorium on deep injection wells. Since the Youngstown event, Ohio has initiated a set of reforms to its Class II deep injection well program that include additional geologic and geophysical data, well testing, monitoring, and operational controls.

Keranen et al., (2013) interpreted three earthquakes that occurred near Prague, Oklahoma, east of Oklahoma City, in November 2011 with magnitudes of 5.0–5.7 as induced by increased fluid pressures from underground injection. The initial rupture was within 200 meters of active injection wells and within 1 km of the surface; they interpreted the lowered effective stress on nearby faults as the result of 18 years of injection. They described an increase in significant earthquakes in the U.S. continental interior concurrent with an increase in the volumes of fluids related to unconventional resource production being injected into the subsurface. The authors concluded that this indicates that decades can pass between the start of injection and incidents of induced earthquakes.

Following publication of the abstract for Keranen et al. (2013) and subsequent news articles, David Hayes (2012), Deputy Secretary of DOI, clarified some points about the USGS's work. Among the preliminary findings described, he stated:

> USGS's studies do not suggest that hydraulic fracturing, commonly known as "fracking," causes the increased rate of earthquakes. USGS's scientists have found, however, that at some locations the increase in seismicity coincides with the injection of wastewater in deep disposal wells.

Hayes (2012) went on to explain that injection of wastewater is known to have the potential to cause earthquakes. However, of the 150,000 Class II wells in the United States, including approximately 40,000 for oil and gas operations, only a tiny fraction have induced earthquakes large enough for public concern. He noted that there are no methods available to anticipate whether an injection will trigger earthquakes large enough to cause concern. The USGS is working with DOE and EPA to better understand induced seismicity.

In March 2013, the OGS (Keller and Holland, 2013) concluded that the Prague event resulted from natural causes, and that further study will improve monitoring and understanding of seismicity in Oklahoma. These authors analyzed earthquake and 3-D reflection seismology, formation data, and historical data, observing that the Prague event was consistent with what is known about natural earthquakes in Oklahoma.

The NRC (2012) found that underground injection of wastewater poses some risk for induced seismicity, but that very few events have been documented over the last several decades compared to the large number of operating disposal wells. The NRC also noted that "the long-term effects of a significant increase in the number of wastewater disposal wells for induced seismicity are unknown" (NRC, 2012).

The NRC (2012) presented their findings, identified gaps in knowledge or information, proposed actions, and recommended further research to address induced seismicity potential in energy technologies. Referring to all energy technologies, they proposed that a local seismic monitoring array be installed in locations where a relationship may exist between extraction/injection and seismic activity. When seismic events appear to be associated with hydraulic fracturing and are cause for concern for public health and safety, an assessment should be performed to understand the causes of the seismicity. Regarding disposal injection wells, the NRC recommended adoption of a best-practices protocol, and where operations could induce unacceptable levels of seismicity; full disclosure and public discussion are needed before operations begin. The NRC outlined practices to consider induced seismicity and develop technology-specific best practices protocols to reduce the possibility of and to mitigate the effects seismicity. They refer to a recent protocol for geothermal systems developed by DOE for geothermal systems (Majer et al., 2012).

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6 LAND USE AND DEVELOPMENT

Land use and development issues associated with natural gas production include property rights disputes and use of public lands; local surface disturbance; cumulative landscape impacts; habitat fragmentation; and traffic, noise, and light. Concerns have been expressed with competing uses for public lands, the cumulative impacts of multiple industries (e.g., timber and tourism), and denial of access to areas with active operations (CMSC, 2011). Surface disturbance involves not only site preparation and well pad construction, but also road, pipeline, and other infrastructure development. The cumulative impacts of surface disturbance can extend over large areas and can also result in habitat fragmentation that impacts both plant and animal species. Mitigation options include adoption of best-practices for site development and restoration, avoidance of sensitive areas, and minimization of disturbed areas. As development and production operations proceed, local residents can be confronted with increased truck traffic, sometimes more than 1,000 truck trips per well, and additional noise and light as construction, development, drilling, and production typically proceed 24 hours per day. Vertical wells are typically spaced with 40 acres per well, the drill pads from which each horizontal well originates are typically spaced with 160 acres per well. A single square mile of surface area would require 16 pads for 16 conventional wells, while the same area using horizontal wells would require a single pad for 6–8 wells (NETL, 2009).

6.1 PROPERTY RIGHTS AND PUBLIC LANDS

The Citizens Marcellus Shale Coalition (CMSC) (2011) explored two issues related to impacts of shale gas production on public lands and the other industries that rely on these lands. They also explored the impacts on private property rights. CMSC stated that shale gas development must consider the cumulative impacts on state parks and forests and on timber and tourism industries as part of responsible stewardship of public resources. Property rights and environmental degradation are a growing public concern, and eminent domain laws, drill spacing requirements, and grouping of leased lands could help protect these rights.

Stolz (2011) noted that local disturbances result from the large amounts of land that are needed for well pads and impoundments, and from the fact that the pad remains active as long as a well can be re-stimulated. Regionally, Stolz expressed concern that access to leased areas (on both private and public lands) becomes restricted, and public lands and parks, in particular, are no longer "public," because safety renders them off-limits.

A presentation by William Lanning of the BLM (2013b) explained that any oil and gas development on lands owned by the federal government is managed by agencies including the BLM or USFS. For resources that are either privately owned or owned by the state, development and regulation is many times managed at the state level, but federal agencies still control the oversight of the development at a high level (BLM, 2013b).

6.2 SURFACE DISTURBANCE

The Sierra Club expressed concern with regional transformation and landscape change from increasing shale gas production (Segall and Goo, 2012). Regionally, hundreds of thousands of new wells and their accompanying infrastructure can require significant construction activity in rural areas with thousands of trucks moving on a growing network of roads (Segall and Goo, 2012). Locally, each well pad covers about three acres with an equivalent amount for infrastructure, and much of this area remains disturbed through the life of the well, as long as 20–40 years.

The development process begins with preparation and construction of access roads and the well pad site. The operators clear vegetation and level the ground's surface, creating additional space for the trucks and drilling rig. As drilling proceeds, the operators bring in equipment to mix the water, additives, and sand needed for hydraulic fracturing—tanks and pumps, as well as water and sand storage tanks, additive storage containers, and monitoring equipment. Based on the geological characteristics of the formation and climatic conditions, operators may excavate pits or impoundments, or use tanks, to store freshwater, drilling fluids, or drill cuttings. Operators may also install pipes temporarily to move materials on- and off-site. As is the case with other construction activities, erosion controls may be needed to contain or divert sediment away from surface water or else precipitation and runoff can carry sediment and other pollutants into nearby surface waters (GAO, 2012).

A BLM (2013a) presentation stated that the use of land for oil and gas development should have as small a footprint as possible, and the development should be viewed as a temporary use of the region. The three phases of land use include planning before development, minimizing impacts during development, and restoration of the land following completion.

Drohan and Brittingham (2012) investigated topographic and soil characteristics that could affect infrastructure development and reclamation success of shale gas pads in Pennsylvania. They determined that the development related to a single shale gas pad ranges 0.1–20.5 hectares (ha) with a mean size of 2.7. More than half of the pads in Pennsylvania are built on slopes with risks of excess surface water movement and erosion. About three-quarters of the pads are built on soils without drainage problems, while almost a quarter are built on potentially wet soils. Aerial photographs show that some pads have been restored and planted with grass. Some crop production could be observed on restored agricultural lands. Poor soil reclamation may limit re-vegetation of grasslands and forests.

The low natural permeability of shale reservoirs requires closer well spacing intervals than conventional gas reservoirs to optimize production. However, the horizontal drilling technology now used in shale gas plays allows for more wells to radiate outward from a single pad. For example, 6–8 horizontal wells can be drilled from a single pad and equal the production of 16 vertical wells developed on 16 pads to cover an area of 1 mile by 1 mile (259 ha). This also reduces the miles of roads and pipelines, and the amount of infrastructure needed (DOE, 2009). An assessment of impacts from oil and gas development in EPA's Region 8 (Colorado, Montana, North Dakota, South Dakota, Utah, and Wyoming) agreed that using horizontal drilling allows several wells to be drilled from a single pad, which would lower the amount of land required (EPA, 2008).

Considine et al. (2012) analyzed notices of violations (NOVs) issued by the Pennsylvania Department of Environmental Protection from January 2008 through August 2011 that were related to Marcellus shale gas drilling. While 62 percent of the NOVs were administrative or

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preventative, the remaining 38 percent represented 845 polluting environmental events that produced 1,144 environmental violations. The Considine et al. study categorized these environmental violations into major and non-major events and identified 25 major events. Major events included "major site restoration failures, serious contamination of local water supplies, major land spills, blowouts and venting, and gas migration" (Considine et al., 2012). Violations related to site restoration made up two of the 25 major violations (land spills and water contamination composed 17 of the 25, or 68 percent) and 39 percent of minor violations, composing the most frequent category of minor violation.

Site restoration events result when the operator does not restore a drilling site in accordance with Pennsylvania Department of Environmental Protection guidelines, including removal of drilling equipment and waste and restoration of 70 percent of the perennial cover within nine months. Erosion was a problem cited in most NOVs; in some cases, equipment was not removed, or vegetation was not restored. Land disturbances have an environmental impact, but they can be remediated with minor reclamation efforts and are not as serious as spills and water contamination (Considine et al., 2012).

6.3 Cumulative Landscape Impacts

Slonecker et al. (2010) quantified the landscape changes and consequences of Marcellus Shale and CBM natural gas extraction in Pennsylvania. Because the combined effects of these two methods create potentially serious patterns of landscape disturbance, disturbance patterns were digitized and used to measure changes. By 2010, 300,000 ha, or 0.41 percent of the land area, in Bradford County and 223,000 ha, or 0.85 percent of the land area, in Washington County had been disturbed by shale and CBM natural gas production. Their results illustrate the effects of natural gas extraction in Pennsylvania on the landscape, primarily in disturbance to agricultural and forested areas.

Drohan et al. (2012) examined land cover change due to shale gas exploration in Pennsylvania, with an emphasis on forest fragmentation. This development has taken place mostly on private property and on agricultural and forest lands. Most drill pads have one or two wells; fewer than 10 percent of pads have five or more wells. As of June 2011, the development of all permits granted would convert 644–1,072 ha of agricultural land and 536–894 ha of forest, plus at least 649 km of new roads and additional pipelines. Drohan et al. (2012) recommended a regional strategy to help guide infrastructure development and manage habitat loss, farmland conversion, and risks to waterways.

A report compiled for the U.S. Department of Agriculture examined the impacts of natural gas development at a site in the Monongahela National Forest (Adams et al., 2011). Adams et al. estimated that a total land area of 1.4 ha would be cleared, including the well pad site and access road. Major impacts that were investigated include the erosion of soil and sediment, water quality, and vegetation condition. The actual land area cleared for the well pad and access road ended up being 0.83 ha, 0.57 ha less than what was originally estimated.

Silt fences were installed around the well pad and near the road to minimize the loss of sediment; however, these measures were not very effective due to several factors. The amount of sediment trapped by some of the fences allowed a conservative estimate of 2.1 metric tons/ha of soil material eroded. The authors reported an unexpected severe impact on vegetation, which was attributed to both the accidental and purposeful release of drilling fluids to the air. In some regions, there was no reported effect the following year, but in others the impacts continued the following year. There were other reported impacts that were unexpected, including heavier than predicted use, procedural and technical changes, and vehicular accidents (Adams et al., 2011).

Stormwater runoff from drilling sites and related infrastructure can impact water quality and ecosystems along local waterways. A site without runoff controls can allow as much as 16 times the runoff of an equivalent vegetated area and natural gas drilling requires about 7–8 acres per well pad. Stormwater flowing across drill sites may contain pollutants from the stored fracturing fluid and produced water on-site. On the other hand, horizontal drilling reduces the number of well pads needed to reach the target formation, so the amount of surface disturbance is less than that needed for purely vertical drilling (The Horinko Group, 2012).

6.4 Habitat Fragmentation

The construction and installation of the infrastructure necessary for development of natural gas can lead to a habitat being converted from a large contiguous patch of similar environments to several smaller, isolated environments. Long-term effects of shale gas production on habitat disturbance will have to be evaluated as the development of these resources proceeds. Mitigation measures such as avoidance, best management practices, and prompt reclamation of the drilling site have been put forward as ways to best minimize the possible impacts that shale gas production may have on habitats. Habitat disruption can also result from a lack of surface water availability in response to withdrawals and quality from erosion and chemical spills. Water use and quality are discussed further in Chapter 4 – Water Use and Quality.

6.4.1 Description of Habitat Fragmentation Impacts

There are several impacts associated with the development of gas drilling sites and gas production that can disrupt the habitat of both plant and animal species. These impacts can arise from a variety of sources and at various points throughout the extraction and production process. Habitat fragmentation occurs when infrastructure must be installed, or land clearing must take place to allow access to a well location. Habitat fragmentation was given as one of the environmental risk pathways that were identified as a consensus priority risk pathway in a survey of 215 experts in government, industry, academia, and non-governmental organizations (RFF, 2013).

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Before fragmentation takes place, a given habitat is considered a single, contiguous region consisting of a type of landscape or environment. Anthropogenic activities and infrastructure can intersect and divide a landscape into a series of smaller, unconnected patches that become more isolated than they were previously (USGS, 2012). Forested areas are particularly vulnerable when land is cleared and leveled for the installation of infrastructure such as roadways and pipelines, leading to a decrease in the forest cover available for plant and wildlife species, and ecosystems (USGS, 2012; GAO, 2012).

Processes having to do with shale gas production can have impacts on habitat and landscapes during all aspects of the operation, including exploration, development, operations, and closure (NETL, 2009). Land, especially land with vegetative growth already present, must be cleared and then graded or leveled so that infrastructure may be installed. Gaining access to the drilling sites means that new roads must be constructed. This results in land disturbance and fragmentation through a habitat. Pathways for pipelines to transport extracted natural gas must also be constructed, leading to similar disruptions as that of road installation. Other necessary pieces of shale gas production infrastructure, including storage tanks and well pads, also lead to habitat fragmentation (GAO, 2012).

The New York State Department of Environmental Conservation (NYSDEC) (2011) released a draft Supplemental Generic Environmental Impact Statement in 2011 to examine potential environmental impacts that could result from shale gas drilling operations in the Marcellus Shale of New York. The study determined that permitting shale gas drilling operations utilizing high-volume hydraulic fracturing techniques would lead to "significant" environmental impacts, including habitat fragmentation and declines in wildlife population and overall biodiversity. There would be both short- and long-term impacts due to the activities associated with the shale gas drilling process, mainly those discussed in the previous paragraphs (NYSDEC, 2011).

A USGS (2012) report examined the effect of natural gas extraction during 2004–2010 on landscapes in two Pennsylvania counties: Bradford County in northeastern Pennsylvania and Washington County in southwestern Pennsylvania, both of which are located in the interior of the Marcellus Shale region. The authors used several landscape quantification metrics to analyze the landscape changes over the period. Forest regions are especially affected by habitat fragmentation, as large contiguous tracts of forest are broken up into smaller, more isolated patches of forest as a result of drilling infrastructure. Exhibit 6-1 provides a depiction of the effect that drilling infrastructure such as roads, well pads, and pipelines can have on forested land (USGS, 2012). The graphic shows forest area in McKean County, Pennsylvania, where natural gas development has taken place and fragmented the habitat into smaller patches. There were four results that pertained to forest fragmentation from this study (USGS, 2012):

- There were a greater number of individual forest patches, each averaging less area in 2010 than in 2001.
- There were over 300 more individual sections of forest in Bradford County in 2010, with an average area almost 3 ha less in 2010.
- There were over 1,000 more individual sections of forest in Washington County in 2010, with an average area almost 7.5 ha less in 2010.
- Much of the increase in the number of individual forest patches was due to the construction of pipelines for product transport.

Exhibit 6-2 shows cumulative impacts for a non-forested area in Wyoming, which shows some of the increased erosion and soil runoff due to the lack of stabilizing vegetation (USGS, 2013). Areas like this may require different remediation and site restoration approaches.

Exhibit 6-1. The effect of landscape disturbances on forest habitat

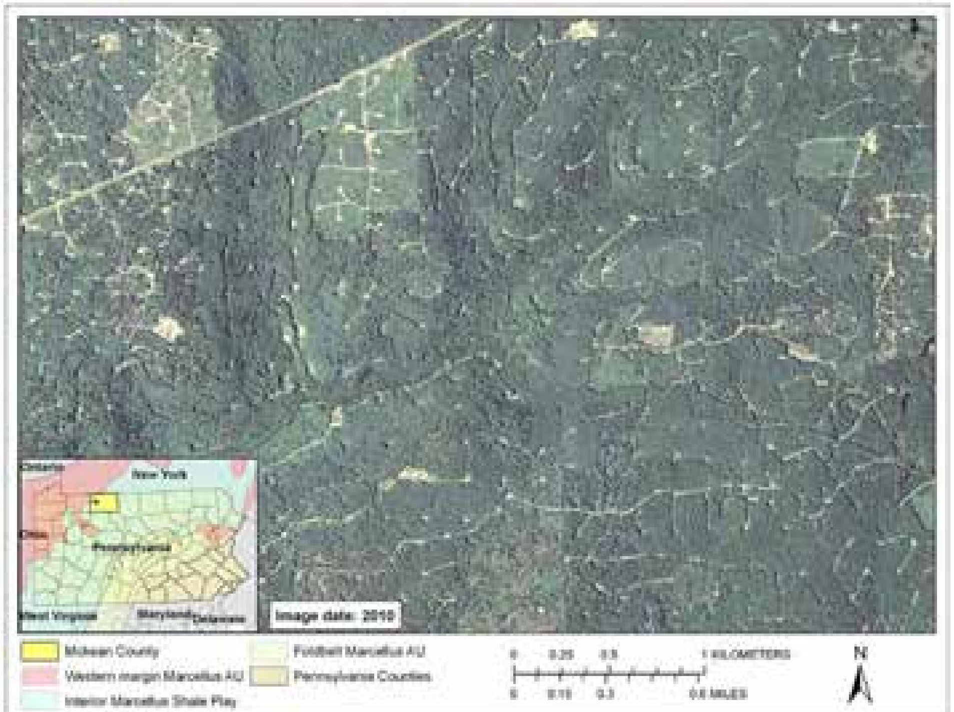

Exhibit 6-2. The effect of landscape disturbance on non-forest habitat (Wyoming, USA)

The Wilderness Society (2008) performed an analysis of the impacts that oil and gas development can have on wildlife due to habitat fragmentation using metrics for road density and distance to the nearest road. The scenario simulation they performed involved randomly locating well pads on a map grid, creating road segments to service the well pads from existing roadways, and converting the data for comparison with current development (The Wilderness Society, 2008). The report found that habitat fragmentation and impacts on wildlife happen even at low well pad density and (though this analysis and available literature can help inform BLM decisions) site-specific evaluations are the best way to determine the extent of habitat fragmentation and impact of development (The Wilderness Society, 2008).

The Wilderness Society (2008) made seven recommendations to allow impact analysis under the National Environmental Policy Act:

- Analyze the impacts of all the available development alternatives
- Evaluate the development impacts at maximum well pad density
- Include possibilities that do not develop important wildlife habitats
- Ensure that analyses are done at the scale of the landscape
- Make use of geographic information systems in analyses
- Recognize more involvement from the public and other stakeholders when landscape analysis is utilized
- Monitor wildlife indicators to measure the effect of any habitat fragmentation

A study by The Nature Conservancy (2010) analyzed Marcellus Shale development in Pennsylvania and projected the impact it would have on natural habitats. Each current Marcellus well pad and accompanying infrastructure results in approximately 8.8 acres of cleared forest and 21.2 additional acres of forest edge habitat. They estimate that by 2030, 60,000 new wells will be drilled, resulting in 6,000 new well pads, if there are 10 wells per pad; 10,000 new well pads, if six wells are drilled per pad; and 15,000 new well pads, if four wells are drilled per pad (The Nature Conservancy, 2010). This amount of development would require 10,000–25,000 miles of additional installed pipeline. The amount of new forest edge habitat as a result of increased development, a range of 400,000–1,000,000 acres, could result in increased predation, changes in the local environment, and increased nonnative species (The Nature Conservancy, 2010).

According to a GAO (2012) report, it is difficult to quantify the long-term effects of shale gas production on habitat fragmentation, because there has not been sufficient time to evaluate these effects. The data do not yet exist to enable a reliable evaluation of what may be the long-term effects of shale gas development. A joint study by the Houston Advanced Research Center and the Nature Conservancy evaluated how surface disruptions, such as the installation of a well pad and drilling rig and the noise levels from equipment running at the drill site, would affect a species of prairie chicken (GAO, 2012). It was determined that the noise did not seem to negatively affect the chickens; however, the drilling rig being there in general led to the chickens temporarily vacating the vicinity (GAO, 2012). The longer the operations are in place, the easier it will be to quantify the long-term effects of shale gas production.

The examination of a natural gas development site in the Monongahela National Forest provided evidence that the installation of a pipeline to transport extracted gas created 3,000 meters of forest edge habitat from approximately 2 ha of cleared right-of-way. These forest edges can provide easy access for predators to nests as well as openings for invasive species (Adams et al., 2011). An assessment performed by EPA (2008) stated that there are concerns over migratory disruption, habitat disruption, and locations where some animals spend the winter that stem from oil and gas development.

Many development operations have been in practice for far longer than shale gas drilling, such as conventional natural gas production and other unconventional gas production (tight gas and CBM). The impacts of habitat fragmentation due to these similar processes are far better known and, therefore, habitat fragmentation impacts and mitigation measures can be understood fairly well. Habitat fragmentation impacts vary greatly depending on the landscape, the extent of exploration, production, and development, and any existing infrastructure or corridors in the vicinity prior to the development of gas resources.

6.4.2 Mitigation Options for Habitat Fragmentation Impacts

The NYSDEC (2011) study proposed that, if the development area included a region of continuous forest over 150 acres in size or a region of grassland over 30 acres, an ecological assessment should be conducted to identify best management practices.

A 2012 study of hydraulic fracturing practices in the Inglewood oil field in California, operated by the Plains Exploration & Production Company proposed that the best way to mitigate habitat fragmentation impacts is to adopt best management practices, perform wildlife surveys, and implement restrictions during migration and mating seasons (Cardno ENTRIX, 2012). The study also found that ensuring that well pad reclamation occurs is the most productive method to reduce harm to populations (Cardno ENTRIX, 2012).

Avoiding disturbances to sensitive areas such as wetlands, waterways, and wildlife habitats when locating drilling sites could be the best method for mitigating impacts. Reclaiming the land upon completion of drilling activities is the best way to mitigate impacts in those cases when avoiding disturbances is impossible (NETL, 2009). Proceeding with reclamation processes as quickly as possible can minimize the disturbances, but all mitigation measures (including avoiding disturbances to begin with) are subject to the landscape, plants, and wildlife that are present at a site.

The Western Governors' Association (2006) released a handbook outlining the best management practices for CBM development to be shared among the Association's shareholders. The practices are split into multiple categories, including planning, water, landowner relations, and infrastructure. Several subcategories can be applied to mitigating habitat fragmentation, such as protection of wetland areas, roads and transportation, pipelines and power lines, habitat and species protection, and wells. To protect wetland and riparian areas, facilities such as well pads should be sited outside of such regions as much as possible, and features that cut across the landscape, such as roads and pipelines, should avoid crossing wetlands and riparian areas as much as possible (Western Governors' Association, 2006). Best practices for mitigating disturbance from roads and transportation include keeping road development to a minimum, using existing access roads as much as possible, using unimproved roads as little as possible during wet weather, following road construction and maintenance standards, avoiding sensitive areas, and attending to safety issues and other problems (Western Governors' Association, 2006). Recommendations of best practices for pipelines and other lines include using existing pathways, installing as many lines as possible in a single location, and using the least invasive construction equipment possible. To protect habitat and sensitive species, lines should be buried rather than installed above ground if possible. Well sites should minimize the amount of surface disturbance that occurs and should be reclaimed as quickly as possible upon completion of development activities (Western Governors' Association, 2006). Again, these best management practices have been developed in areas of CBM production by the Western Governors' Association, but many of these practices are applicable to shale gas development.

Drilling on federal or public lands is subject to oversight by federal agencies, and sections of the Endangered Species Act may require that species of plants or animals not be threatened by the permitted drill site (NETL, 2009). Mandatory plans for mitigation and reclamation may be required to ensure that impacts on wildlife and habitat will be as minimal as possible (NETL, 2009).

With approximately 33 units of the National Park System in or near the Marcellus Shale, NPS found it important to be informed and current with development issues. Moss (2012) provides an overview of the geology, technology, current activity, and potential environmental impacts. Among the effects described are widespread development and well spacing, site space needs, water use, aquifer contamination, air quality, and truck transportation. There are then four recommendations to help park units prepare for potential shale gas development on and around NPS lands (Moss, 2012):

1. Check land and mineral ownership – Know if private in-holdings or private or state mineral estate underlie an NPS unit.
2. Be aware of industry interest adjacent to park boundaries – Land speculation, exploration, or drilling could signal increased requests for drilling permits. Contact the state oil and gas agency to express concerns and issues.
3. Work with state agencies – Meet with the state permitting agency, establish agreements, engage before issuance of permits, and if possible, have protective mitigation measures included directly in the lease.

The NPS Geologic Resources Division assists parks with policy and technical issues and reviews permitting and environmental documents to help mitigate or eliminate adverse impacts (Moss, 2012).

In January 2013, the BLM updated a presentation detailing best management practices for wildlife management that can help to minimize habitat fragmentation. The document offers several practices that can be implemented or planned to lessen impacts on habitat. The well pad itself and the immediate surroundings can be fit to the space available to minimize the disturbed area, rather than constructing a generic rectangular pad (BLM, 2013a). There are also multiple examples of reclamation practices, both at the drill site and on access roads, that can be implemented to lessen the impact of the infrastructure. The well pad and supporting infrastructure (roads, pads, storage, and pipes) can be designed to be as efficient and minimally obstructive as possible (BLM, 2013a). Wells can be remotely monitored using telemetry, pipelines and other lines can be buried where possible, and any existing corridors for roads and lines should be used whenever possible (BLM, 2013a). It is helpful to monitor local wildlife populations to ensure that mitigation and reclamation measures are effective, and final reclamation upon abandonment of the well is critical to the long-term effectiveness of mitigation options (BLM, 2013a).

6.5 Traffic, Noise, and Light

In the *Revised Draft Supplemental Generic Environmental Impact Statement on The Oil, Gas and Solution Mining Regulatory Program*, NYSDEC (2011) identified temporary but adverse noise and visual impacts from construction activity and increased truck traffic among the potential land-use environmental impacts associated with natural gas production. Significant adverse impacts in terms of damage to local and state roads could also result. Among mitigation measures described for environmental impacts, NYSDEC suggests imposing measures to reduce the adverse noise and visual impacts from well construction. A transportation plan could also be required that would include proposed truck routes and assess road conditions along the proposed routes. Exhibit 6-3 tabulates the number of truck trips for a typical shale gas well (MIT, 2011).

Exhibit 6-3. Truck trips for a typical shale gas well drilling and completion

Activity	1 Rig, 1 Well	2 Rigs, 8 Wells
Pad and Road Construction	10–45	10–45
Drilling Rig	300	60
Drilling Fluid and Materials	25–50	200–400
Drilling Equipment (casing, drill pipe, etc.)	25–50	200–400
Completion Rig	15	30
Completion Fluid and Materials	10–20	80–160
Completion Equipment (pipe, wellhead, etc.)	5	10
Fracturing Equipment (pump trucks, tanks, etc.)	150–200	300–400
Fracture Water	400–600	3,200–4,800
Fracture Sand	20–25	160–200
Flowback Water Disposal	200–300	1,600–2,400
TOTAL	1,160–1,610	5,850–8,905

The large volumes of water involved in fracturing operations can create high volumes of road traffic given the majority of the water used for fracturing is transported by truck. It should be emphasized that the large number of traffic movements shown in the table above are worst-case estimates. In particular, re-use of flowback wastewater significantly reduces the amount of road traffic associated with hauling water, which represents much of the traffic movement. Furthermore, large-scale operators are also using pipelines to transport water to the site, substantially reducing the amount of road traffic (MIT, 2011). An assessment performed by EPA (2008) in their Region 8 stated that the trucks and roads that are used during oil and gas development processes affect the surrounding environment through localized noise pollution.

The Eagle Ford Shale Task Force Report for the Railroad Commission of Texas identified increased traffic and deterioration of roads and bridges among the infrastructure impacts from shale gas development (Porter, 2013). Exhibit 6-4 lists estimates of the number of truck-trips-per-shale-gas-well in the Eagle Ford (Porter, 2013).

Exhibit 6-4. Loaded truck trips per gas well

Activity	Number of Loaded Trucks
Bring well into production	1,184
Maintain production (per year)	Up to 353
Re-fracturing (every 5 years)	997

These impacts are enough of a concern that the task force considered alternative financing methods to help meet the increased demands on roads and bridges (Porter, 2013).

Upadhyay and Bu (2010) surveyed the visual impacts of Marcellus drilling and production sites in Pennsylvania. They reviewed the drilling process, assessed direct visual impacts, and compared the results to the impacts of other technologies (e.g., windmills and cell towers). They also studied drill-pad density from map and aerial perspectives to examine the likelihood of seeing drill towers across a landscape, and the modeled potential impacts for increased drilling, making the following conclusions:

- Serious impacts from light and noise are a potential problem within a small radius of drilling sites
- Indirect impacts like increased truck traffic, equipment storage, and temporary structures compose the most salient visual impacts, rather than the drill pads themselves
- Timelines for site restoration of visual impacts vary significantly

Upadhyay and Bu (2010) recommended that visual impacts be addressed during the siting and design phase and that nighttime impacts could be avoided by pointing lights downward.

The RFF (2013) report also gave several options in their survey of experts under the category of community disruption. Included in this category, as well as habitat fragmentation, were such risks as light pollution, noise pollution, odor, and road congestion. The industry respondents identified a number of these community disruptions as risk pathways of high priorities, while the other respondent groups identified more conventional (air pollution, water pollution, etc.) risks.

SEAB recognized that shale gas production brings both benefits and costs to communities, often rapidly, including places that are unfamiliar with natural gas operations. Impacts include traffic, noise, and land use, with little or no allowance for planning or effective mechanisms to engage stakeholders. SEAB does not believe that these kinds of issues will solve themselves or that regulation or legal action will solve them. State and local governments should lead experiments with alternative mechanisms for addressing these issues constructively and seeking practical mitigation. The federal government may also help through mechanisms like the U.S. Department of Interior's Master Leasing and Development Plans, which might help improve planning for production on federal lands (SEAB, 2011).

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7 SOCIAL JUSTICE AND NATURAL GAS/LIQUEFIED NATURAL GAS MARKET DEVELOPMENT

7.1 INTRODUCTION

Granting authorizations to import and/or export natural gas into and from the United States could potentially generate and, in some cases, further perpetuate instances of energy, environmental, and social injustice. Conversely, if potential impacts to disadvantaged communities are both carefully considered and minimized, then opportunities to advance environmental, energy, and social justice may also be present. Ensuring the advancement of energy, environmental, and social justice across the domestic natural gas market, however, requires the foundations upon which the critical infrastructure necessary to support additional authorizations to import and export natural gas is built in such a manner that brings historically disadvantaged communities to the planning table and ensures exposure to harms for these communities are minimized.

These types of considerations have driven the implementation of the Biden-Harris Administration's Justice40 initiative, which has an explicit goal that 40 percent of the benefits from federally funded projects should be accrued within historically disadvantaged and disenfranchised communities and communities burdened by pollution. Specific types of projects include those related to the energy transition both in energy production and the effort to electrify transportation. Additional categories include affordable housing and workforce development and training, as well as those focused on the remediation of legacy pollution, clean water initiatives, and wastewater projects. Introducing the Justice40 framework to the ways in which government measures the distribution of project benefits attempts to right the historical wrongs that have resulted in the unequal outcomes seen today by requiring the success of projects to be measured according to whom the benefits and disbenefits are distributed (Justice40, 2023).

This chapter seeks to summarize the incorporation of social, environmental, and energy justice concepts found in the broader research literature as they relate to natural gas and LNG market development. The goal is to summarize what already exists and provide guidance as to how future research might be pursued at the nexus of social, energy, and environmental justice and project development. This literature review specifically focuses on the development of large-scale energy infrastructure intended to serve the energy-transition goals outlined by the current administration and its policies. However, the challenge (and opportunity) researchers face in this space is rooted in the relatively light focus that has been spent on applying energy, environmental, and social justice concepts to the development of energy infrastructure projects specifically for natural gas and LNG markets.

Due to the nascency of research that links social justice issues with the development of natural gas and LNG markets, this literature review will cover research that has already connected these issues and weave together the separate literature areas into the discussion. For a guiding light, this review uses the structure presented in Spurlock et al. (2022) that outlines a tractable

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Commented [HSAJ71]: Tim/Amy/Tom – Is it okay to include these three pillars of justice or are you wanting to focus on just one (e.g., environmental). It seems as of right now that the bulk of the discussion is related to energy justice. Should we expand and include more on environmental?

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Commented [HSAJ73]: I really appreciate the way this paragraph helps to frame the chapter.

Commented [HSAJ74]: If Tim/Amy/Tom agree change social to social, environmental, and energy throughout.

framework to incorporate energy justice tenets into energy infrastructure planning decisions and deep decarbonization policy implementation strategies.

This discussion is further framed as a struggle to balance energy justice issues rooted in the unequal accrual of pollution and disbenefits with the need to ameliorate energy poverty where communities do not have equitable access to cheap, reliable energy. This chapter concludes by underscoring the idea that the considerations of energy justice tenets (distributional, procedural, and recognition) must be done from the holistic inflection point of energy project governance as it is the fulcrum of all project planning, development, and implementation. It is from the point of governance that the effort to ameliorate energy poverty through the implementation of energy justice can produce a just transition away from a carbon-intensive economy and toward a more sustainable outcome.

7.2 Distributional, Procedural, and Recognition Justice

The three core tenets of assuring energy justice are the assurance of distributional, procedural, and recognition justice (Spurlock et al., 2022). To aid in the understanding of energy justice writ large, the following subsections provide background on these three tenets.

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7.2.1 Distributional Justice

Distributional justice is focused primarily on the equitable distribution of benefits and dis-benefits across communities (Spurlock et al., 2022). It is a concept focused on the well-being of individuals, which spans the gambit of human outcomes such as psychological well-being, societal well-being, and physiological well-being (Deutsch, 1975). Distributional justice delves into the nuanced context in which equity versus equality versus need may dominate in identifying unjust distributions.

Fairness is a key concept within distributional justice and can be characterized as a problem for geospatial analysis (Bouzarovski and Simcock, 2017). Across the energy supply chain, distributional justice is a problem of implied risk responsibility as well as costs and benefits (Heffron and McCauley, 2014). In addition to inequities created by a historical lack of inclusiveness is the risk that those structural deficits will compound under a changing climate. In other words, unless addressed the deficits of the past will likely increase as the climate changes much like a revolving line of credit tends to grow faster over time when a balance is carried from one period to the next.

7.2.2 Procedural Justice

Spurlock et al. (2022) presents procedural justice as essentially the effort to include all voices. They posit that disadvantaged communities are overburdened and underserved and their disenfranchisement can only be corrected when their voices are intentionally included in the start-to-finish process of project and policy development. In other words, stakeholder engagement must be done early and often to ensure the priorities of disadvantaged communities are codified in the priorities of the project or policy.

Procedural justice takes a more holistic view of outcomes from the perspective of group perception. Researchers break the impacts of procedural justice into three core areas of effect: voice, dignitary process, and fair process. The voice effect is the positive behavior observed in communities engaged with a decision-making process when the individual feels heard. The effect of dignitary process is best described as respect. When an individual's dignity is preserved, the community buy-in to the procedure grows. Finally, the fair-process effect describes the positive community behaviors that arise when the group perceives the existence of procedural justice. In a sense, the effect of fair process augments the effects of the dignitary process and the power of voice (Lind and Earley, 1992).

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7.2.3 Recognition Justice

At its core, recognition justice deals with respect. Spurlock et al. (2022) presents the concept as a demand to recognize that divergent views exist on the best pathways for energy project development and strategies to address issues of climate justice. Those views reflect the unique, diverse backgrounds of these communities who present the perspectives and opinions reflective of their histories. Incorporating those voices in the energy transition is critical to ensuring policymakers implement project development that seeks to serve all. Equitable outcomes begin with the recognition that disenfranchised communities will require effort to enfranchise and empower their members to ensure their histories and perspectives are heard in a meaningful way.

Commented [HSAJ80]: I also think of consideration.

Recognition justice seeks to provide for fair representation, safety, and the general creation of an environment that is welcome to all. McCauley et al. (2013) identify issues of recognition injustice in terms of how policy might treat those characterized as "energy poor" with the classic example of the behaviors of elderly household energy use. Looking at the overall higher average energy use, United Kingdom policymakers view the issue as an education problem where the assumption was that elderly people do not understand the long run impacts of small behavior changes. The authors reveal that framing choices in way that nudged elderly households towards the intended policymaker outcome required acknowledging that older people need warmer houses for their health and well-being. Strategies for changing behavior are more effective when normative behaviors within the community, culture, or ethnicity are recognized.

7.3 Energy Justice

Under-girded by the three tenets of distributional, procedural, and recognition justice, energy justice acts as a guiding concept for activism (McCauley et al., 2013). A broad literature review on the topic of energy justice (Qian et al., 2022) shows that the recent growth and focus on energy justice has quickened in pace with renewable energy driving interest. Debating the definition of energy justice has been a robust area of discussion for researchers, but there exist a few core concepts that underpin most approaches. At its heart, assuring energy justice deals with the issue of addressing energy poverty and branches out from the broader focus of environmental justice (Iwińska et al., 2021).

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While the focus on the justice of energy distribution is not new, it has grown in salience as the public increasingly accepts the need to transition from fossil fuels based systems of energy production and consumption to clean alternatives . Using energy justice as a decision-making framework, Iwińska et al. (2021) outlines the focus of this literature as one that seeks to consider how the policy-making framework surrounding the generation and consumption of energy can be fairer. In this sense, energy justice acts as a tool, helping to guide policy design.

On one hand, Iwińska et al. (2021) considers the energy justice concept as a "boundary object" whose conceit is to accelerate the inculcation of these principles in policymaker innovation and across all cultural boundaries—much like a change agent. On the other hand, these authors debate the merits of treating the concept as a standard rather than a boundary object. Standards on energy justice would more easily be incorporated into policy in tractable forms that are quantitative and qualitative, though likely at the loss of a unifying definition (Iwińska et al., 2021).

Digging beyond the core tenets of energy justice, Sovacool and Dworkin (2015) acutely characterize the conceptual metrics by which broader approaches to energy justice may be measured. Those include the need to measure the costs communities face with a special emphasis on the level of inequity across communities relative to the distribution of these costs. Sovacool and Dworkin (2015) also identify the need to distribute benefits to these same communities. Though it seems logical to measure the costs *and benefits* to disadvantaged and disenfranchised communities, historical focus has more often been on mitigating or compensating losers for costs rather than on how project design can seek to benefit disenfranchised communities. Their very disenfranchisement may relegate them to an after-the-event consideration (when considered at all), which highlights costs over benefits. The simple statement that benefits should be considered alongside costs may act to nudge the focus back toward before-the-event planning.

Sovacool and Dworkin (2015) list procedure as the critical element that can act to bridge the cost-benefit foci. The process by which energy project development flows can be exclusive by nature; this would naturally prohibit the participation of disenfranchised communities who, again by definition, are not empowered to advocate as robustly as the enfranchised communities. By shaping the process from the core concept of inclusivity, the authors underscore that achieving inclusivity requires intentionally embracing it as a central goal to achieve fairness in energy project planning.

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Iwińska et al. (2021) outlined the various foci of energy justice research. The current dominant topic has been renewable energy, as energy transition efforts have driven the growth of interest in energy justice. Summarizing the remainder of the subtopics of energy justice in broad terms, the research falls within the categories of energy poverty, energy policy, law, and governance.

Results from the transition away from fossil fuels are producing differentiated outcomes that vary by community. Energy justice studies reveal that some communities are clearly benefiting from the increased access to renewable energy technology and opportunities while others assume the burdens of change. Those communities that seem to be accruing the adverse health outcomes and increased cost of cleaner technology are the same historically disenfranchised peoples who often fail to reap the job gains and regional economic growth opportunities of change. Nonprofit organizations tend to lead in the effort to ameliorate these inequitable outcomes (Carley et al., 2021).

Pellegrini-Masini, Pirni, and Maran (2020) make the case that the prevalence of energy justice definitions inhibits the capacity of policymakers to deploy these concepts toward the greater good. They highlight several useful but nuanced approaches with Guruswamy (2010) underscoring the "energy oppressed poor" as those suffering from an inequitable distribution of energy as a resource, which is innately about distributional justice.

7.4 Energy Poverty

Poverty is a dominant issue that arises often in research focused on energy. As policies are implemented to attenuate the worst effects of climate change, the focus on carbon emissions as a flow and stock necessarily highlights how these costs are going to be born geospatially. Carbon mitigation policies themselves also present societal costs that are unequally burdening communities based on how much of the remaining carbon budget impoverished communities might need. But at its heart, energy justice is an issue of economic opportunity as access to safe, affordable energy is a necessity to meet basic human needs and pursue economic growth opportunities (Piwowar, 2022).

Commented [HSAJ83]: Can we describe further? Flow or stock pollutant?

Bouzarovski and Petrova (2015) identify the criteria and conditions that drive energy poverty as the material and/or social deficit in energy services accrued by communities. The authors outline two key issues. First, deficits in domestic energy access and supply are the direct result of ineffective socio-technical mechanisms that fulfill energy demand at the household level of energy services such as heating and lighting. Second, "vulnerability thinking" often drives or exacerbates these outcomes. That is to say, the perceived likelihood of becoming impoverished can drive outcomes, frame processes, and generally lead to the undesired outcome as a result of historical perceptions or perspectives (Hall et al., 2013).

Okushima (2021) attempts to measure the "basic carbon needs" of a community. These are the total carbon emissions an individual community might need to attain an "adequate level of domestic energy services." Okushima's case study of Japan highlighted that basic carbon needs varied based on differences in several factors within a community including the type of domestic dwelling, community demographics, and variation in climate characteristics across regions. Affluence allows people to rely on carbon-alternative energy sources and can change basic carbon needs. Moreover, Okushima (2021) found that balancing the ability of all communities to meet their energy needs with decreases in their basic carbon needs is the critical factor for achieving some equitable progress on climate change.

Commented [HSAJ84]: Need or bare?

The importance of energy poverty may have increased in recent years as a function of the world's increased attentiveness to climate change risks, but Campbell (1993) points to the 1970s oil crises as the flux point at which energy poverty challenges to political stability were revealed. Those latent risks to social cohesion were evident in communities dominated by lower incomes, access to inefficient heating technology, and sub-standard governmental guidelines for housing insulation. However, the sudden rise in oil prices catalyzed those latent risks into active disruptions that were exacerbated as policymakers introduced mechanisms to ration supply.

Campbell (1993) identifies the conceptual term "poverty" as an issue that confounds action on the problem of energy poverty. Poverty is identified as a multi-generational condition without tangible points of action to take. To most, the state of poverty is a state of being. This is a challenge without boundaries—that formlessness tends to overwhelm policymaker action especially when considering the issue as multi-generational.

Energy poverty, on the other hand, is an infrastructure problem that capital expenditures can directly cure because household expenditures on fuel are quantifiable; therefore, a threshold exists in theory where energy poverty begins and ends (Campbell, 1993). Campbell points to Boardman (1987) who posited that 10 percent of one's household income being spent on energy/fuel was the threshold of concern for energy poverty—a metric adopted by several others (Green et al., 2016; Lloyd, 2006; Lesser, 2015). Spending above 10 percent indicated a state of energy poverty whereupon the cost of fuel consumption to meet one; s energy service needs was a burden.

Follow-on research has expanded on this effort to measure energy poverty by creating a metric of threshold for energy poverty. While some countries have adopted specific metrics for measuring and comparing energy poverty (Faiella and Lavecchia, 2021), there is no clear consensus on best practices. Chapman and Scannell (2005) developed the Affordable Warmth Index based on the calculation of energy ratings to identify sources of energy that need efficiency investments by policymakers and households. Several others have made contributions, for example, Siksnelyte-Butkiene et al. (2021), Thomson and Snell (2013), Heindl (2013), Miniaci et al. (2014), Okushima (2016), and Brunner et al. (2012).

Regardless of the methodology for measuring energy poverty, the fundamental issue at hand is that the lack of affordable warmth changes people's basic daily routines. The onerous nature of accommodating these energy deficits tends to drive health and wealth outcomes for households (McCrone, 2015). The lack of affordable energy can bind communities to a lack of economic opportunity as they attempt to accommodate for energy deficits or their high costs, which tend to affect minorities and people of color more intensely.

The myriad impacts of energy poverty on health are too numerous to cover in this document, but Faiella and Lavecchia (2021) outline several. Overall, households with limited incomes are energy poor and suffer from subsequent negative health outcomes (Thomson et al., 2017), for example, excess deaths during wintertime (McAvoy et al., 2007) with the elderly particularly at risk (de'Donato et al., 2013) and increasing seasonal variation due to climate change compounding these risks (Healy, 2003). For healthcare systems, this increased seasonal health risk can reduce economic activity and reduce the integrity of the broader healthcare system (Wells, 2007) with compounding effects to the system over time (Torjesen, 2012).

Negative outcomes tend to accumulate across multiple community contexts, but their effect is not felt in isolation. Rather, these negative community outcomes tend to have cumulative effects that interact and compound each other with the risk of cointegrated impacts higher with LNG project development (Gislason and Andersen, 2016).

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Commented [HSAJ86]: There is also research suggesting 6% is the more accurate threshold beyond which energy/fuel expenses become a burden.

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7.5 JUST ENERGY TRANSITIONS

The current energy transition presents a generational opportunity to make significant progress in ameliorating historical injustices (Wang and Lo, 2021). As technology has evolved and capital has flowed into large-scale energy infrastructure investments, a concerted effort to accrue the economic and social benefits associated with these technologies and investments in disadvantaged communities should prove fruitful. Equally possible is the ability to start mitigating the systemic injustices that have continued to plague these same communities in response to historical decision-making.

Commented [HSAJ88]: Within what context? In achieving the administration's Justice40 goals?

The articulation of energy transition goals varies significantly across the research literature, but it tends to boil down into a handful of broad topics. These include poverty reduction (Lo and Broto, 2019; Koehn, 2008; Colenbrander et al., 2017), amelioration of historical energy injustices (Jasanoff, 2018; Delina and Sovacool,2018; Carley and Konisky, 2020), and opportunities for economic growth (Yang et al., 2018; Ehresman and Okereke, 2015). Wang and Lo (2021) argue that the energy transition is an apt vehicle for fixing historical wrongs if it can simultaneously account for environmental costs disadvantaged communities already suffer from, the reality that climate change will likely exacerbate these pre-existing environmental costs, and a decision-making process steeped in the tenets of assuring energy justice.

Pellegrini-Masini et al. (2020) attempt to prioritize the approach toward justice and the energy transition across four planes. First, the tradeoff in intergenerational outcomes and opportunities must be a prominent consideration for policymakers. This addresses the core reason that mitigating climate change is essential: subsequent generations should be provided the opportunity for growth and well-being that is at least commensurate with today's generations. Second, building out policy that considers energy vulnerability will help to prevent the transition from being a zero-sum game in which regional, fossil-fuel-reliant economies are left behind. In this sense, energy projects will benefit vulnerable communities. Third, transforming the social self-image of communities whose cultural identity is tied to fossil fuels must be considered to avoid confusing the energy transition with an attack on disadvantaged communities. Finally, the unavoidable damage to local communities must be accounted and compensated for.

The ability to move forward into a new energy landscape that is sustainable is a direct function of the ability of policymakers to avoid repeating historical injustices; justice frameworks must be the bedrock of transition planning (Wang and Lo, 2021; Williams and Doyon, 2019). Pai et al. (2020) provide the framework for researchers to consider strategies for a just transition—one that preserves the well-being of fossil-fuel-reliant communities. Preserving the human capital of these communities is a critical goal for ensuring the energy transition policy provides opportunities for all. Pai et al. (2020) summarize more than a dozen requirements that would facilitate policymaker efforts to ensure a just transition but underscore one: the requirement of intentional effort for long-term planning with routine efforts to conscientiously engage with affected communities. Historically disenfranchised communities of people must be actively welcomed into the discussion early and often to be re-franchised and ensure their voices are heard (Weller, 2019).

7.6 FOSSIL FUEL EMPLOYMENT

As the United States shifts away from a carbon-intensive economy, the delicate issue of fossil fuel employment arises. Specifically, in regions where fossil fuel and other extractive-based or refining industries have historically dominated available employment opportunities and been the core driver of local economic growth in the region.

The capacity to politicize energy transition debates is high (Healy and Barry, 2017) with carbon-intensive firms in a unique position to rally action against clean-energy projects (Goods, 2022) as a tradeoff between community well-being and climate policy. There is some merit to this concern from the community perspective as well. Female employment in the solar industry lags far behind male employment (Carley and Konisky, 2020) and disadvantaged or disenfranchised communities tend to bear a larger overall burden of costs even those associated with cleaner energy projects (Brock et al., 2021). To the extent that governance strategies can acknowledge the dignity of historically disadvantaged communities and groups, efforts to engage with them in energy transition and governance strategies will be more successful and less divisive (Grossmann and Trubina, 2021).

Unions are viewed as an amenable structure for elevating and empowering the voices of disadvantaged communities in the energy transition (Pai et al., 2020; Newell and Mulvaney, 2013). One reason may be in the high unionization rate of fossil-fuel industries (Pai and Carr-Wilson, 2018). Engaging with unions is in many ways a matter of practicality, but the pre-existing internal structures built to advocate for their members make them a strong vehicle for working toward a just transition[i] (Stevis and Felli, 2015).

Intentional efforts to diversify local economies would increase the resilience of local economies (Lobao et al., 2016). Notably, increasing the diversity of local economies is a positive regardless of the effort to transition away from fossil fuels. Any local economy highly dependent on one industry—particularly when that industry is as volatile as extractive-based industry—would introduce a greater resilience supportive of regional growth (Freudenburg and Gramling, 1994).

Among the opportunities a just transition presents are the ability to reduce the gender gap in regions dominated by the fossil fuel industry, increase investment into local infrastructure, remediate historical environmental damage, retrain the local workforce to "skill up" the region's human capital, and shore up local government revenues through economic diversification (Pai et al., 2020).

In the end, just transitions are achieved when local voices are not just heard but amplified during the energy transition process. An unfortunate trend can play out that misses the mark on this issue where well-intentioned decisionmakers attempt to prescriptively advocate on behalf of disadvantaged communities. Often, policymakers advocate for the environmental protection of disadvantaged communities while neglecting to consider the calls for economic development emanating from those communities. A key example of that rests in the Canadian arctic where LNG projects that could act as local development opportunities for increasing local

Commented [HSAJ89]: This section could provide a clearer description of the main justice considerations related to employment within a fossil-fuel based industry during the energy transition. It seems like a good place to introduce employment declines in regions where fossil-based extractive industries are located and discuss how authorizations to import and export natural gas could address these employment declines but lead to further injustices.

Commented [HSAJ90]: Maintaining or addressing losses of ?

Commented [HSAJ91]: Can we put this statement in terms of employment?

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[i] The term "just transitions" originated within community-organizing efforts centered on labor unions (Eisenberg, 2018).

incomes are prevented by national policies that have banned energy projects out of the best intentions (Nicol and Barnes, 2019).

One obvious benefit of large-scale energy project development rests in the rents accrued from the project's completion. Treating these project benefits as a viable source of income that could be distributed to disadvantaged communities was explored in Chandrashekeran (2021), who studied indigenous populations in Australia after land repossession within Aboriginal populations. Chandrashekeran (2021) found that establishing property rights for historically disenfranchised populations is a key step in empowering collective negotiations for revenue sharing to fund reparations.

7.7 Protests and Political Activism

Excluding communities creates risks not just for disadvantaged populations, but for the completion of large-scale energy project development overall (Temper et al., 2020). The perpetuation of community disenfranchisement leaves people with a sense that the only option available for advocacy is to organize and protest. The way in which narratives are framed matters a great deal with respect to facilitating buy-in from communities.

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Janzwood and Millar (2022) argue that the duality of natural gas—that it simultaneously accelerates the transition as a baseline electricity input and ensures the perpetuation of carbon reliance—creates the conditions for interpretive politics to dominate discourse around the transition. This is especially true for LNG organizations planning large infrastructure projects (Korkmaz and Park, 2019) and when regional economies are reliant on fossil fuels or the topic of natural gas as a "bridge fuel" is debated (Rosenbloom, 2018; Cha, 2020).

On the other side, anti-coal and anti-gas advocacy groups proved their own capacity to organize effectively in developed economies (Durand and Keucheyan, 2022). Social movements such as a the "UK Rights to Warmth" in the United Kingdom have coalesced around the fight against entrenched energy poverty to some success (Walker and Day, 2012). Successful efforts to stop LNG export projects have been found even in fossil fuel-friendly U.S. states such as Texas (Garrett and Sementelli, 2021) with access to social media and the strategic deployment of online networks increasing their efficacy (Correa-Cabrera et al., 2022).

The willingness to protest varies across cultures. Whereas communities within the United States that are at risk of job losses from national policies might tend to view justice as a regional tug of war that *must be* fought, research into Chinese activism shows that the Confucian perspective on justice as a collective outcome (whose goals are harmony between nature and humanity) shifts the perspective of the debate at its core (Wang and Lo, 2022). However, a nation or region's reliance on fossil fuels is not a reliable indicator of attitudes toward natural gas and LNG projects. Case in point, protestors in Canada and Norway have vehemently advocated against the expansion of oil and gas exploration despite their deep reliance on oil and gas production for both economies (Harrison and Bang, 2022). It has also been found that protests can arise in areas where there is a history of oil extraction when unconventional natural gas exploration is proposed (Chailleux et al., 2018).

The politicization of energy infrastructure can result in starkly divided factions, but the common thread of discontent that binds pro-gas and anti-gas contingencies is rooted in process. Specifically, deficits in procedural and distributional justice tend to increase the likelihood of activism (Evensen, 2018; Temper et al., 2020).

7.8 Energy Governance

Governance structures play a vital role in the pursuit of energy project development and the transition away from fossil fuels, but their ability to provide an equitable or just transition is not guaranteed (Moss, 2009). Incorporating the concept of just outcomes begins with the governance structures of energy project development and planning (Newell and Mulvaney, 2013). Those who are in the position of governance are in a position of authority to inculcate more equitable outcomes to benefit disadvantaged populations (Florini and Sovacool, 2009).

As Florini and Sovacool (2009) point out, governance is not simply government. While governance is an activity in which governments participate it exists as a framework for creating and maintaining processes to implement policy. This framework is the conduit for participation that brings together government, intergovernmental organizations, private sector market participants, and communities to collectively manage a process that ideally serves all groups.

Governance is necessary as a result of two issues with which economists often wrestle. One issue is that society is not capable of ensuring equitable access to public goods without some overarching set of rules to facilitate that outcome and a governance structure to provide oversight over implementation. The second issue is that any economic or social activity tends to create what economists call "externalities." That is, there are unintended results that can occur indirectly from the consumption of goods or social interactions. The decommissioning of a coal power plant is a prime example of the need for governance to protect the public's well-being from externalities, as an idle power plant could become the source of negative health outcomes for a community without intentional efforts to prevent such outcomes. Governance structures are necessary to deal with these two conceptual issues because there is no economic incentive to do so (Florini and Sovacool, 2009).

Perspectives can clearly vary within communities and that variation can affect governance structures (Wang and Lo, 2021). In studying international natural gas markets, Norouzi (2022) notes that the heterogeneity of individual members within a collective community implies that international natural gas market outcomes are heavily influenced by individual preferences within any collective. Community engagement is important, but it is not the magic elixir that solves the problem by itself. Ciplet and Harrison (2019) identify three conflicts that emerge in efforts to provide for an energy transition: 1) between inclusivity and sustainability where inclusive processes that invite community engagement require more time to complete projects; 2) between sustainability and the need to recognize the unique value system for each community, which increases the complexity of sustainability goal pursuits; and 3) between equity and sustainability, meaning that the distribution of costs and benefits can conflict with project performance.

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The impact of a region's political economy can also clearly drive outcomes. Inequality is a multi-dimensional concept that varies across countries and individuals (Laurent and Zwickl, 2021). As the communist states of the Eastern Bloc exited the Union of Soviet Socialist Republics, the effort to integrate into energy markets within the European Union revealed that variations in culture and geography dominated some preferences in energy project outcomes with respect to energy justice (LaBelle, n.d.). On the other hand, a study of sub-Saharan African nations revealed a positive relationship between democracy, energy justice, and growth (Opoku and Acheampong, 2023). Cultural differences aside, income and wealth inequality may drive many of the outcomes. Studies of European Union attitudes toward sustainability policies show that 41 percent country-level variance in negative attitudes is correlated with differences in wealth and income (Pellegrini-Masini et al., 2021).

In short, the lack of consideration for energy justice issues within the global framework of energy governance will likely just perpetuate historical disadvantages within communities (Symons and Friederich, 2022). This is a function of existing power structures within current governance structures. Beyond that, Symons and Friederich (2022) show that the political sovereignty of communities making independent decisions over energy project development will always result in outcomes that serve each group's self-interest and ignore the externality problems. Without intentional adjustments to governance that deal with these structural problems, the current paradigm will continue to create winners and losers and perpetuate the current disenfranchisement of some communities.

Good governance strategies for energy project development require support from the government, reliable capital and operational funding, diversification goals for the economy, and diverse coalitions (Wang and Lo, 2021; Cha et al., 2020). Finally, the creation of ownership stake opportunities at the onset of project development for disadvantaged communities is critical to ensuring that the tradeoffs between disenfranchised communities and the regional benefits of energy projects ameliorate losses. Greater rates of acceptance have been found to exist within communities with larger ownership stakes in energy projects (Hogan et al., 2022).

7.9 SUSTAINABLE DEVELOPMENT

The desire to balance environmental protection and economic development in disadvantaged communities has led to the championing of a concept called "sustainable development." Summarized broadly, the idea is to balance the needs of current generations without harming the well-being of future generations. Within this movement, the needs of today's impoverished communities are heavily weighted under the theory that gains in wealth and income of today's generation beget gains in tomorrow's generation. In other words, the benefits of economic development compound over generations (Poppel, 2018).

In practical use, the concept of sustainability can be vague (Grossmann et al., 2022). One oft-missing area of focus is the tradeoff between environmental protection advocacy for disadvantaged communities and advocacy with these same communities for energy justice and sustainable development. The concept of embedded sustainable development outlines criteria for energy project development to be measured in terms of how energy justice efforts compare to the energy privilege of communities (Ciplet, 2021).

In 2015, the United Nations outlined a list of 17 Sustainable Development Goals that define the focus of sustainability as a practice (United Nations, 2015). Oriented toward 2030 outcomes, the 17 outcomes broadly fall into Barbier's (1987) canonical "three systems" approach to process development: environmental, social, and economic. Broadly speaking, the 17 goals break down into the promotion of clean water and sanitation services alongside sustainable cities and sustainable economic growth with full employment as well as the sustainable development of natural resources. They also promote the end to food insecurity and poverty, greater levels of societal health and well-being, lifelong inclusive/equitable educational opportunities, and gender equality, as well as strong judicial and governmental institutions. Finally, the United Nations (2015) advocates for the proactive implementation of climate change policy that results in infrastructure resilience where communities have access to reliable and affordable clean energy.

Cherepovitsyn and Evseeva (2020) proffer several criteria to promote sustainable development within the context of LNG project development in the arctic—an area currently receiving a great deal of attention for energy development projects. The authors note the importance of sustainable development in the arctic as it is home to over 20 percent of the world's hydrocarbon resources. To promote sustainable outcomes, they propose seven criteria of sustainable development goals[i]:

- Project development must minimize environmental impacts at the construction and operation site.
- Natural resource use should be efficient.
- Local community support is paramount as is the effort to preserve indigenous culture and heritage.
- Long-run regional economic gains that benefit and reflect stakeholder expectations should be prioritized.
- Larger infrastructure development goals are achieved.
- Innovations to industry technology are achieved.
- Strengthening the regional LNG market relative to the global network is achieved.

7.10 CONCLUSION

Historical disenfranchisement of communities has often resulted in the creation of winners and losers with respect to policy impacts. To the extent that the existence of disadvantaged communities can be attributed to those policy impacts, they are the result of the lack of inclusivity in the planning and implementation processes of project development. As the United States embarks on a transition away from a carbon-intensive economy, the chance to right those historical wrongs presents itself.

The calls to advocate for energy justice during this transition have grown as the salience of climate change threats grows. Achieving a just transition is largely a functioning of process. The

Commented [HSAJ97]: This section needs to include but is currently missing 1) a detailed description of how disadvantaged communities are identified by the DOE, 2) the different tools available to locate disadvantaged communities, and 3) how those tools might be used to inform authorizations to import/export natural gas.

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i Note that while the framework for measuring outcomes by Cherepovitsyn and Evseeva (2020) focuses on the arctic, this approach may be prudent for any LNG project development strategy. As such, the seven points have been modestly edited to apply more broadly.

once-in-a-lifetime opportunity to restructure current processes around the core concepts of distributional, procedural, and recognition justice is significant. Re-framing the foundations upon which critical U.S. infrastructure is built by bringing diverse voices and stakeholders to the planning table will help to ensure that the best laid plans produce results that facilitate the growth for all, not just some.

To do so, there is a need to accept the existence of frictions innate to energy justice and energy poverty. Providing economic growth opportunities in carbon-intensive regional economies is as paramount as the need for ensuring reliable, affordable, and clean energy for those suffering from a historic lack of energy access. This may require adjusting the method of measuring the benefits and costs of large-scale U.S. energy infrastructure investments. The implementation of the Biden-Harris Administration’s Justice40 initiative speaks to this effort.

This chapter provides the framework for pursuing inclusivity goals in its discussion of energy justice and energy poverty. The energy transition is presented as a catalyst for pursuing change with the intended outcome being a just transition for all. In the end, the vehicle for applying energy justice and energy poverty goals rests in the inclusive design of energy governance structures.

The literature base of energy justice and energy poverty within the space of natural gas and LNG market development is strong and growing. With intentionality, the authors of future research can help to ameliorate those historical disenfranchisements and provide a framework for the kind of shared prosperity that induces strong growth for all.

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From: Harker Steele, Amanda J.
Sent: Wed, 30 Aug 2023 21:14:57 +0000
To: Easley, Kevin; Curry, Thomas; Sweeney, Amy; Skone, Timothy
Cc: Robert Wallace; Adder, Justin (NETL); Francisco De La Chesnaye
Subject: LNG Regulatory Analysis Support - Task 4 Env. Review Update Ch. 1-6
Attachments: Deliverable_8_30_23.zip

Hi Tom, Amy, Tim, and Kevin,

*DRAFT*DELIBERATIVE*PRE-DECISIONAL*

Good afternoon! The team has been hard at work updating Ch. 1 - 6 of the report and I am happy to report we are ready to submit today instead of on Friday.

The attached zip folder includes 1) a revised clean version of the report (Ch. 1 - 6) with a few minor comments for your consideration and 2) a comment response log which contains comments from the reviewed version of the report sent to NETL on 8/21 and updated to reflect the parsed down version of Ch. 2 sent by Tom on 8/22.

I hope you all have a good rest of the week! We look forward to getting your feedback. Thanks!

Sincerely,
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Response to Comments for ~~POTENTIAL ENVIRONMENTAL IMPACTS ASSOCIATED WITH UNCONVENTIONAL NATURAL GAS~~ ENVIRONMENTAL IMPACTS AND JUSTICE CONSIDERATIONS ASSOCIATED WITH UNCONVENTIONAL NATURAL GAS

Comment Number	Reviewer	Comment	Resolution
2.	Tom Curry	I've made some edits for consideration.	Further adjusted the title so the image and content fit on one page.
3.	Tom C	Note that header needs to be updated to reflect final title.	Adjusted
5.	Tom C	This is too strong a conclusion. I think the point is made in the first sentence of the previous paragraph.	Agreed. Adjusted.
6.	Kevin Easley	Tim Skone / NETL Team - plz revise if any of this is inaccurate. During the 2011 NPC 'Prudent Development of O&G Resources' report effort, the Halliburton representative shared with the group that hydraulic fracturing and other techniques developed in or that evolved further with unconventional resource recovery were being applied extensively to conventional plays / wells to boost / accelerate ultimate recovery.	See adjustments made to paragraph 4 of Chapter 1 -Introduction, including the two additional footnotes added (b, c). Also footnote g in section 1.1.
7.	Kevin E	Also, from the PA DEP: ***What is a conventional gas well?** A conventional gas well, also known as a traditional well, is a well that produces oil or gas from a conventional formation. Conventional formations are variable in age, occurring both above and below the Elk Sandstone. While a limited number of such gas wells are capable of producing sufficient quantities of gas without stimulation by hydraulic fracturing, most conventional wells require this stimulation technique due to the reservoir characteristics in Pennsylvania. Stimulation of conventional wells, however, generally does not require the volume of fluids typically required for unconventional wells. URL: https://www.dep.pa.gov/Business/Energy/OilandGasPrograms/Act13/Pages/Act-13-FAQ.aspx	Our goal was to make the point that in addition to be used to access oil & natural gas from unconventional formations, hydraulic fracturing techniques have also been used to (further) stimulate production from conventional wells. However, we did not want to confuse the reader on the difference between conventional and unconventional natura gas. The PA DEP website's definitions for unconventional vs. conventional wells was somewhat confusing to follow. Specifically, the highlighted sentence in their definition for conventional wells.
8.	Kevin E	NETL Team - this observation comes from the NPC 2011 North American Resource Development (NARD) report's Executive Summary (pg. 21, found at https://www.npc.org/NARD-ExecSummVol.pdf), citing the following reference: *IHS Global Insights, Measuring the Economic and Energy Impacts of Proposals to Regulate Hydraulic Fracturing, 2009; and EIA, "Natural Gas and Crude Oil Production," December 2010 and July 2011.*	Added the reference from the NARD to report – see NPC (2011). Did not add HIS specifically because we were not able to locate a "hard" copy and its pre-2011. We did delete the "For example, as far back as 2011, the National Petroleum Council found that up to 95% of new wells being drilled in North America were hydraulically fractured." Because we were not able to cross check whether it 95% of conventional/unconventional/ or both types of wells. Its also a slightly dated statistic (pre-2011) and we could not find similar information for ~pre-2022.

Response to Comments for ~~POTENTIAL ENVIRONMENTAL IMPACTS ASSOCIATED WITH UNCONVENTIONAL NATURAL GAS~~ ENVIRONMENTAL IMPACTS AND JUSTICE CONSIDERATIONS ASSOCIATED WITH UNCONVENTIONAL NATURAL GAS

9.	Tom C	I think the description of what we view as in scope is consistent. Try to avoid introducing terms like "upstream" unless they are necessary.	Done
10.	Tom C	Want to make this active voice.	Done. Also adjusted some more throughout Ch. 1
12.	Kevin E	Again, innovations that initially emerged in shale gas development were soon applied so shale oil and conventional oil and gas development.	Addressed. See resolutions from above.
13.	Tom C	NETL, please fact check my edits to this sentence. Gas can be transported as compressed natural gas but it is not as economic as LNG. The point is that liquefaction allows for more MmBtus in a smaller space, making it more economic (presumably) to transport or store the gas.	Adjusted. Added reference.
14.	Tom C	Can you add a sentence about the amount of natural gas production from unconventional sources and then break it down into shale gas, CBM, and tight shale (consistent with the definitions above)?	We were unable to find unconventional production broken out by type so we summarized what was available on the EIA website for dry production onshore by unconventional type. https://www.eia.gov/energyexplained/natural-gas/where-our-natural-gas-comes-from.php We can reach out to the EIA to review this section if you'd like and also add an exhibit to support if you prefer.
15.	Kevin E	NETL Team - plz add the Acronyms for the Statutes I've inserted to the Acronym List. Thx!	Done
16.	Brian Lavoie	Only unconventional wells? Or all oil & gas wells?	Gas and Oil wells. Adjusted.
17.	Kevin E	NETL Team - are 'lands reserved from the public domain' a special category of USFS covered acreage? If so, do we need to say more about what that means? And if not, suggest you revise 'lands reserved from the public domain' to 'forest acreage they manage.'	Added footnote with definition.
18.	Kevin E	NETL Team - plz add EIS to the Final Acronym List.	Done
19.	Tom C	I rearranged the paragraphs here to put the air regulations together and the water regulations together.	N/A
20.	Kevin E	NETL Team - plz add POTWs to the Acronym List.	Done
21.	Kevin E	NETL Team - plz add MARAD to the Acronyms List.	Done
22.	Tom C	NETL Team - here is the source for this reference; plz format accordingly: https://cdphe.colorado.gov/press-release/colorado-adopts-first-of-its-kind-measures-to-verify-greenhouse-gas-emissions-from	Done
23.	Kevin E	NETL Team - here is the source for this reference; plz format accordingly: https://oklahoma.gov/occ/news/ news-feed/2022/clyde-earthquake-directive.html Here is another OK source that backs up the state's response to compel operators to manage / limit various activities to reduce incidences of induced seismicity (and regulators and operators alike are implementing these new 'controls' by placing priority attention on sites where seismic events induced by O&G activity occurred previously):	Added Skinner 2018 source.

		https://oklahoma.gov/content/dam/ok/en/occ/documents/og/02-27-18protocol.pdf Also, here are further details on OK's 'Clyde Earthquake Directive' that the source I provided cited (but, ironically, that page was 'taken down' after I sent you the URL – WEIRD!): https://oklahoma.gov/occ/news/news-feed/2022/clyde-earthquake-directive.html	
25.	Tom C	This approach is an improvement but I worry about the ability to complete it on schedule. I would expect a section on air emissions that includes PA, CO, and NM. I would expect a section on GHGs that includes CO and NM.	No longer applicable.
26.	Tom C	We are proposing a revised approach that is at an even higher level in the interest of meeting the current deadline.	
27.	Tom C	Are we confident that these results still represent the state of regulation?	No longer applicable.
28.	Tom C	Why is this reference different than the reference on the graphic?	No longer applicable.
29.	Tom C	Did NETL confirm these statements are still accurate? Or is this based on the 2014 report?	No longer applicable.
30.	Tom C	This image is rather fuzzy - if we are going to use it, we should have a higher quality image.	No longer applicable.
31.	Tom C	When we asked for permission to use this, did the author indicate or make any representation about whether the results from the 2013 were still reliable?	No longer applicable.
32.	Tom C	Is this section summarizing TX regulations?	No longer applicable.
33.	Tom C	Be sure to update the references to include any new references and to remove any references no longer being used.	Done
34.	Tom C.	"[Use information from section 3.7 of the GHG inventory to provide additional information about the GHG emissions from natural gas systems. Start with total emissions and then breakdown emissions between CO2, CH4, and other GHGs]"	Change made.
35.	Tom C.	I'm not sure of the point of this paragraph and table. Is it to compare to Exhibit 2-8? I'm not confident the two are comparable. Exhibit 2-8 shows estimates from three different studies of 2015 methane emissions. Exhibit 2-9 does not include an estimate of 2015 methane emissions. Is the goal to suggest that EPA's most recent estimate is closer to the Rutherford and Alvarez study? If so, 2015 data should be pulled from the 2023 GHGI and converted to Tg CH4/year to compare to Exhibit 2-8.	Per Tom's suggestion in separate Chapter 2 document, I have made changes accordingly.
34.		Tom C	I would prefer if this sentence were referenced to the IPCC AR5.
35.		Tom C	I would prefer this sentence reference IPCC AR6.
36.	Kevin E	NETL Team / Tim Skone - in Ch. 1, I pointed out a reference from the 2011 NPC Prudent Development Study (in its Executive Summary) claiming up to 95% of all new wells drilled involve hydraulic fracturing operations. In a NPC CSC meeting, this was a major 'finding' shared by the Halliburton representative participating in that Study and a CSC member. The assertion is backed up by an EIA and an I.H.S. source cited in that Executive Summary. In the Halliburton officer's oral comments, he asserted this 'up to 95% of new wells drilled' covered	Exhibit 2-1 modified per Tom's suggestion. Exhibit 2-1 modified per Tom's suggestion.

<table>
<tr><td></td><td></td><td>both unconventional AND conventional. This was thought to be a 'big deal' during that CSC meeting and Sue Tierney - one of the leading contributors to the 2011 NPC Prudent Development report, wanted to be sure we captured that 'factoid' in the final report, to essentially make the case that modern production operations with drilling for new wells almost always includes fracking - for both unconventional and conventional. The Exhibit 2-1 indicates 'hydraulic fracturing (unconventional).' It's probably fine to leave the flow diagram as is but I wanted to raise this here for you and Tom - and our NETL Team experts - to consider.</td><td rowspan="2"></td></tr>
<tr><td>35.</td><td>Tom C</td><td>I would suggest we change the pre-production box to say "Hydraulic Fracturing" instead of "Fracking (unconventional)"</td></tr>
<tr><td>36.</td><td>Tom C</td><td>In this example, where do the CO2 emissions come from?</td><td>Changed from GHG to CH4. Studies just focused on CH4.</td></tr>
<tr><td>37.</td><td>Tom C</td><td>Have the studies "noted" that top-down leads to an upward bias? Or is that an observation that NETL is making?
I would say top-down studies tend to have higher estimates of emissions and bottom-up approaches tend not have lower estimates of emissions but I don't think the studies themselves indicate a bias.</td><td>The studies themselves (Alvarez and Rutherford) use the word “bias”. This is not an independent observation NETL is making.</td></tr>
<tr><td>38.</td><td>Tom C</td><td>NETL study: Fayetteville Study: Basin Reconciliation - Energy Institute (colostate.edu)
NREL study: Natural Gas Emissions: Measure Top-down or Bottom-up? | News | NREL
EDF: PermianMAPFinalReport.pdf (edf.org)</td><td>Studies have been included.</td></tr>
<tr><td>41.</td><td>Tom C</td><td>I don't think this last sentence is correct.

Table 7.15 | Emissions metrics for selected species: global warming potential (GWP), global temperature-change potential (
cycle responses as described in Section 7.6.1.3. Combined GTPs (CGTPs) are shown only for species with a lifetime less than 20 years (Section 7.
years and is applied to a change in emissions rate rather than a change in emissions amount. The radiative efficiencies are as described in Section
adjustments where assessed to be non-zero in Section 7.6.1.1. The climate response function is from Supplementary Material 7.SM.5.2. Uncerta
in Supplementary Tables 7.SM.8 to 7.SM.13. Chemical effects of CH_4 and N_2O are included (Section 7.6.1.3). Contributions from stratospheric o
species metrics are not included. Supplementary Table 7.SM.7 presents the full table.
<table>
<tr><th>Species</th><th>Lifetime (Years)</th><th>Radiative Efficiency ($W\ m^{-2}\ ppb^{-1}$)</th><th>GWP-20</th><th>GWP-100</th><th>GWP-500</th><th>GTP-50</th><th>GTP-100</th><th>CGTP (yea</th></tr>
<tr><td>CO_2</td><td>Multiple</td><td>$1.33 \pm 0.16 \times 10^{-5}$</td><td>1.</td><td>1.000</td><td>1.000</td><td>1.000</td><td>1.000</td><td></td></tr>
<tr><td>CH_4-fossil</td><td>11.8 ± 1.8</td><td>$5.7 \pm 1.4 \times 10^{-4}$</td><td>82.5 ± 25.8</td><td>29.8 ± 11</td><td>10.0 ± 3.8</td><td>13.2 ± 6.1</td><td>7.5 ± 2.9</td><td>2823 ±</td></tr>
<tr><td>CH_4-non fossil</td><td>11.8 ± 1.8</td><td>$5.7 \pm 1.4 \times 10^{-4}$</td><td>79.7 ± 25.8</td><td>27.0 ± 11</td><td>7.2 ± 3.8</td><td>10.4 ± 6.1</td><td>4.7 ± 2.9</td><td>2675 ±</td></tr>
<tr><td>N_2O</td><td>109 ± 10</td><td>$2.8 \pm 1.1 \times 10^{-3}$</td><td>273 ± 118</td><td>273 ± 130</td><td>130 ± 64</td><td>290 ± 140</td><td>233 ± 110</td><td></td></tr>
<tr><td>HFC-32</td><td>5.4 ± 1.1</td><td>$1.1 \pm 0.2 \times 10^{-1}$</td><td>2693 ± 842</td><td>771 ± 292</td><td>220 ± 87</td><td>181 ± 83</td><td>142 ± 51</td><td>78,175 ±</td></tr>
<tr><td>HFC-134a</td><td>14.0 ± 2.8</td><td>$1.67 \pm 0.32 \times 10^{-1}$</td><td>4144 ± 1160</td><td>1526 ± 577</td><td>436 ± 173</td><td>733 ± 410</td><td>306 ± 119</td><td>146,670 ±</td></tr>
<tr><td>CFC-11</td><td>52.0 ± 10.4</td><td>$2.91 \pm 0.65 \times 10^{-1}$</td><td>8321 ± 2419</td><td>6226 ± 2297</td><td>2093 ± 865</td><td>6351 ± 2342</td><td>3536 ± 1511</td><td></td></tr>
<tr><td>PFC-14</td><td>50,000</td><td>$9.89 \pm 0.19 \times 10^{-2}$</td><td>5301 ± 1395</td><td>7380 ± 2430</td><td>10,587 ± 3692</td><td>7660 ± 2464</td><td>9055 ± 3128</td><td></td></tr>
</table></td><td>No change made. A bit confused here. The table you pasted confirms the values articulated in the final sentence.</td></tr>
</table>

Response to Comments for ~~POTENTIAL ENVIRONMENTAL IMPACTS ASSOCIATED WITH UNCONVENTIONAL NATURAL GAS~~ ENVIRONMENTAL IMPACTS AND JUSTICE CONSIDERATIONS ASSOCIATED WITH UNCONVENTIONAL NATURAL GAS

42.	Tom C	Throughout this section, I'd like you to review how you are referring to NETL. Since this is an NETL report, I would expect to say "our LCA" or "we concluded" as opposed to "their LCA" or "its conclusion".	Attempted to adjust. May need to revisit based on further feedback from Tim. We want to refrain from "we" or "our" as the authors didn't conduct the LCAs.
43.	Kevin E	NETL Team / Tim S. - see the earlier point on hydraulic fracturing (a key form of well stimulation) now being featured (since 2011) in up to 95% of all new wells - unconventional and conventional - being drilled.	Exhibit 2-1 modified per Tom's suggestion. See also earlier comment about HIS reference and changes made in text both in Ch 1 & 2 to reflect.
44.	Tom C	Not the correct reference for this sentence.	Corrected
45.	Tom C	I think the above summaries provide enough information, we don't need to include this report.	Removed section.
46.	Tom C	Given the next sentence, should this say "CH_4 and CO_2" or GHG?	Study just focused on CH_4. Change made.
47.	Tom C	Does this range provide an apples-to-apples comparison of the rates? 2 seems incredibly low and 42 seems incredibly high.	
48.	Tom C	The tech editor should revie the use of "super emitter". Should it be super emitter, super-emitter, or superemitter?	All are acceptable variations as long as only one is used for consistency. I changed this occurrence to match the rest.
51.	Tom C	Is this a true statement? Above, Rutherford and Alvarez are quoted as saying methane emissions are 1.5-2.5 times the amount in the GHGI. 2.5 time is 150% higher than the base. The next sentence says the variability is +/- 150 percent. That is not even greater than the other variability.	No longer applicable
52.	Tom C	Further, above, Balcome is quoted as saying "Estimates of combined CH_4 and CO_2 emissions range 2–42 g CO_2e/MJ. " 42 would be 20 times or 2,000% higher than 2.	
53.	Tom C	Given my questions above, my recommendation is to delete this sentence and half. I think the rest of the section stands without this comparison.	No longer applicable. Removed section
54.	Kevin E	NETL Team - I'm uncertain regarding when emission should be singular versus plural in a number of instances in this Addendum. Can you have your Technical Editor use the MS Word 'search and replace' feature to examine individual uses of the terms emission and emissions and ensure the proper use of the term 'emission,' both singular and plural? Thx in advance.	No longer applicable. Removed section.
55.	Tom C	This discussion seems out of place in a section about mitigating GHG emissions from the natural gas supply chain. This paragraph is about the role of gas in decarbonization - which is a separate topic and out of scope for this report.	No longer applicable. Removed section
56.	Tom C	The emissions are not exclusive to exploration and production. For example, you could have natural gas leaks from pipelines.	Modified sentence to be more inclusive.
57.	Tom C	Can you please confirm this with the original source materials? I'm assuming CRS referenced EPA for this statistic. I want to double check it.	Included footnote.
58.	Tom C	I found this sentence confusing since VOCs are discussed separately above. If you keep it, I would suggest clarifying that VOCs include HAPs. That is, I don't think all VOCs are HAPs - but I would like to know if I'm incorrect.	Added footnote for clarity.
59.	Tom C	N_2O - nitrous oxide - is primarily a concern because it is a greenhouse gas. I don't think it adds anything here. Recommend deleting.	

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61.	Tom C	I'm OK with simplifying the numbers in the table but would recommend using 2 significant figures and use some alternative notation for the 0.0000 rows. I made a suggestion in track changes.	Accepted changes
62.	Kevin E	NETL Team - wanted to emphasize production growth is steady as reflected by the Appalachian Basin becoming the most productive for gas US-wide.	Good with the change
63.	Kevin E	NETL Team - in the footnote below, the text says 'hydrocarbon barring.' Don't we want to say 'hydrocarbon bearing' instead?	Correct, accepted the change
64.	Kevin E	NETL Team - I don't want to highlight this potential outcome, per se, but above ground fracking chemical spills do happen accidentally; on an NPC Tour in PA in 2011, we observed a wellsite where it was completely lined for containment purposes - to capture fracking chemicals if they accidentally spilled; unfortunately, such liners / approaches can be costly and aren't the norm).	We will add, but not expound upon
65.	Kevin E	NETL Team - I've seen 'semi-arid' used previously but not semiarid. Perhaps this is fine as MS Word hasn't marked the term as a typo, but I prefer to see it hyphenated. Your all's call.	I checked Google and this is an exception where this is one noun that is hyphenated and not closed. We will keep it hyphenated.
66.	Tom C	I moved this paragraph up, I think it provides a good overview.	Ok
	Tom C	Are we making a distinction between consumption and use? They seem to be used interchangeably. If they are interchangeable, I would like to stick with one - it seems like use it more frequently used.	I will make sure we use 'use' consistently
67.	Tom C	Is induced seismicity an earthquake caused by human activities? If so, this sentence should be revised to "Earthquakes from human activities…". If not, I think the fist two sentences need to be reviewed.	Changed based on Tom's suggestion.
68.	Kevin E	Tom, induced seismicity is indeed caused by human activities from all I've read and know. Here's a nice description: "Among the many impacts of anthropogenic activity on the Earth, one that has caused particular public disquiet in recent years is “induced seismicity,” that is minor earthquakes and tremors caused by industrial processes." (Citation: https://eos.org/editors-vox/the-challenges-posed-by-induced-seismicity)	Also, added the quote and citation that Kevin provided at the beginning of the paragraph.
69.	Tom C	don't think this information is necessary here.	No response
70.	Tom C	Why is this time range different than the one in the previous sentence?	The data on earthquakes is when the dates are taken. I don't think it would make sense to go back and match the dates from the citation we have on earthquakes to the production in the Marcellus during that time. It was my thought that we should use the most up-to-date data on production we have. I am open to discussion.
71.	Tom C	Please add a reference to this sentence.	Done, see below.
72.	Tom C	Are there any DOE or NETL research initiatives we would want to mention in this section?	Added text at the end of the section to address work DOE has done.
73.	Tom C	We are OK with the older references, but the expectation is that the NETL has reviewed the statement and confirmed that it is still accurate.	Agreed and I have done my best to update any old references with newer ones. Also, I

			have checked and have not seen any new material that contradicts the older references.
75.	Tom C	Are my edits here correct?	Yes

ENVIRONMENTAL IMPACTS AND JUSTICE CONSIDERATIONS ASSOCIATED WITH UNCONVENTIONAL NATURAL GAS

August 31, 2023

DOE/NETL-2023/4388

DRAFT DELIBERATIVE PRE-DECISIONAL

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Disclaimer

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The authors wish to acknowledge the excellent guidance, contributions, and cooperation of the NETL staff, particularly:

Commented [HSAJ1]: Note for FECM - To be completed at the end.

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TABLE OF CONTENTS

LIST OF EXHIBITS

ACRONYMS AND ABBREVIATIONS

API	American Petroleum Institute
AR5	IPCC Fifth Assessment Report
B	Billion
Bcf	Billion cubic feet
BLM	Bureau of Land Management
BP	British Petroleum
BTEX	Benzene, toluene, ethylbenzene, xylenes
Btu	British thermal unit
CAA	Clean Air Act
CBM	Coalbed methane
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CH_4	Methane
CMSC	Citizens Marcellus Shale Coalition
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_2e, CO_2-eq	Carbon dioxide equivalent
COGCC	Colorado Oil and Gas Conservation Commission
CRS	Congressional Research Service
CSU	Colorado State University
CWA	Clean Water Act
d	Day
DAC	Disadvantaged community
DOE	Department of Energy
DOI	Department of the Interior
DOT	Department of Transportation
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EPA	Environmental Protection Agency
EPCRA	Emergency Planning and Community Right-to-Know Act
EQ	Earthquakes
ESA	Endangered Species Act
FECM	Office of Fossil Energy and Carbon Management
FERC	Federal Energy Regulatory Commission
ft, FT	Foot
g	Gram
G&B	Gathering and boosting
gal	Gallon
GHG	Greenhouse gas
GHGI	Greenhouse Gas Inventory
GHGRP	Greenhouse Gas Reporting Program
GWP	Global warming potential
GWPC	Groundwater Protection Council
H_2S	Hydrogen sulfide
HAP	Hazardous air pollutant
HF	Hydraulic fracturing
HPh	Horsepower-hour
IOGCC	Interstate Oil and Gas Compact Commission
IPCC	Intergovernmental Panel on Climate Change
ISO	International Organization for Standardization
kg	Kilogram
kJ	Kilojoule
km	Kilometer
km^2	Square kilometers
kWh	Kilowatt hour
LCA	Life cycle analysis
LNG	Liquefied natural gas
m^2	Square meter
m^3	Cubic meter
MARAD	Maritime administration
Mcf, MCF	Thousand cubic feet
min	Minute
MIT	Massachusetts Institute of Technology
mg	Milligram
MJ	Megajoule
ML	Local magnitude
MM	Million
MMT	Million metric tons
Mw	Moment magnitude
MWh	Megawatt hour

NOx	Nitrous oxides
N_2O	Nitrous oxide
NEIC	National Earthquake Information Center
NEPA	National Environmental Policy Act
NETL	National Energy Technology Laboratory
NGA	Natural Gas Act
NGL	Natural gas liquid
NGO	Non-governmental organization
NORM	Naturally occurring radioactive material
NOx	Nitrogen oxides
NPC	National Petroleum Council
NPS	National Park Service
NSPS	New Source Performance Standards
NYSDEC	New York State Department of Environmental Conservation
O_2	Oxygen
OECD	Organisation for Economic Co-operation and Development
OSHA	Occupational Safety and Health Administration
OPA	Oil Pollution Act
OSF	Oral slope factor
PADCNR	Pennsylvania Department of Conservation & Natural Resources
PADEP	Pennsylvania Department of Environmental Protection
PARETO	Produced Water Optimization Initiative
PM	Particulate matter
ppm	Parts per million
PRV	Pressure release valve
POTW	Publicly owned treatment work
R&D	Research and development
RCRA	Resource Conservation and Recovery Act
RD&D	Research, development, and demonstration
REC	Reduced emissions completion
RFF	Resources for the Future
RFI	Request for Information
RfV	Reference value
RPSEA	Research Partnership to Secure Energy for America
RRC	Railroad Commission of Texas
scf	Standard cubic foot
SDWA	Safe Drinking Water Act
SF_6	Sulfur hexafluoride
SO_2	Sulfur dioxide
T-D, T&D	Transmission and distribution
T&S	Transport and storage
Tcf	Trillion cubic feet
tCO_2e equivalent	Tonnes carbon dioxide
TDS	Total dissolved solids
TexNet	Texas' Center for Integrated Seismicity Research
t NG	Tonnes natural gas
Tg	Teragram
tonne	Metric ton
U.S.	United States
UIC	Underground Injection Control
USFS	U.S. Forest Service
USGS	U.S. Geological Survey
VOC	Volatile organic compound
yr	Year

1 INTRODUCTION

The United States (U.S.) Department of Energy's (DOE) Natural Gas Regulatory Program is responsible for reviewing applications to import and/or export natural gas from and/or to foreign countries. An important dimension in considering whether to grant such authorizations is how the additional natural gas production and transport activities needed to support proposed actions may impact the environment.[a] Accordingly, potential impacts are factors affecting public interest during review of applications.

Although uncertainties exist regarding the exact amount and location of natural gas production or transportation that would occur in response to additional authorizations being granted, it is important that DOE provide the public and decision-makers with access to updated information regarding the potential impacts associated with such activities. Accordingly, DOE's National Energy Technology Laboratory (NETL) has prepared this update to the 2014 Addendum to Environmental Review Documents Concerning Exports of Natural Gas from the United States (hereafter the 2014 Addendum) (DOE, 2014).

As with the 2014 Addendum, this report provides a review of peer-reviewed, scientific literature related to the potential environmental consequences of unconventional natural gas production and related activities. As unconventional natural gas production represents the majority and a growing share of total U.S. natural gas production, the environmental impacts reviewed in this report relate primarily those associated with unconventional production activities.

The publications referenced build on a strong body of literature that traces the evolution of unconventional natural gas production techniques from their conceptual stages in the 1970s to the technology advancements that contributed to the shale gas boom of the early 2000s and the further development and recovery of additional unconventional natural gas resources (e.g., tight gas sands, coalbed methane [CBM], and associated gas recovered with shale oil) and to stimulate more production from conventional resources (National Petroleum Council [NPC], 2011 and Commonwealth of Pennsylvania, 2023a).[b,c]

This report summarizes published descriptions of the potential environmental impacts of natural gas operations within the lower 48 states as detailed by government, industry, academia, scientific, non-governmental, and citizen organizations. The sources cited are publicly available documents. While this report by no means represents an exhaustive list of the sources that discuss environmental consequences of natural gas production and related

[a] DOE is responsible for considering the environmental impact of its decisions on applications to export natural gas, including liquefied natural gas, to countries with which the United States has not entered into a free trade agreement requiring national treatment for trade in natural gas. (Applications for trade with free trade agreement countries are deemed to be in the public interest by statute.) DOE conducts environmental reviews under the National Environmental Policy Act and as part of its public interest review under the Natural Gas Act.

[b] In Pennsylvania, hydraulic fracturing, which is primarily used to produce natural gas from unconventional resources, has also been used to help stimulate production from conventional natural gas formations where reservoir characteristics do not otherwise permit sufficient production (Commonwealth of Pennsylvania, 2023a).

[c] A 2011 report by the NPC suggested hydraulic fracturing was responsible for the reversal of long-term declines from onshore conventional production of natural gas in the United States (NPC, 2011).

activities, NETL has determined the sources cited are representative of the literature, and no significant areas have been excluded.

In addition to providing a review of potential environmental impacts, this report also provides the public and decision-makers with information regarding how the justice implications of natural gas production and related activities can be evaluated, as well as how justice can be advanced and promoted in future decisions regarding these activities. The information provided is a result of NETL's review of DOE's Justice40 initiative and other publicly available information.

Over the past decade, the focus on environmental issues has evolved with some interest in the public literature varying over time. Key research in some areas remains the same with minor to no new additions to the basis of scientific knowledge; in this situation, some historical references have been maintained. No opinion on nor endorsement of these works is intended or implied.

This report is divided into chapters, each of which contains a separate section of references so that each identified focus area can be explored further:

- Greenhouse gas (GHG) emissions and climate change (Chapter 2)
- Air quality (Chapter 3)
- Water use and quality (Chapter 4)
- Induced seismicity (Chapter 5)
- Land use and development (Chapter 6)
- Justice considerations for natural gas development (Chapter 7)

Commented [HSAJ2]: Note for PECM - Ch. 7 still exists as a separate document. However, we have made an attempt to incorporate some content into Ch. 1 that outlines what is contained in Chapter 7. Our hope is by doing this now, we can reach a decision sooner on the title and also help to pull Ch. 106 and Ch. 7 together.

This report begins with the presentation of background information on domestic natural gas production and federal and state regulatory processes related to managing environmental impacts.

1.1 Natural Gas Basics

Natural gas is an odorless, gaseous mixture of hydrocarbons, largely made up of methane (CH_4) but also containing small amounts of natural gas liquids (NGLs) and nonhydrocarbon gases (e.g., carbon dioxide [CO_2] and water vapor) (Energy Information Administration [EIA], 2023b). Natural gas is one of the major combustion fuels used throughout the country. It is mainly used to generate industrial and utility electric power, produce industrial process steam and heat, and heat residential and commercial spaces. The average gross heating value of natural gas is approximately 1,031 British thermal units per standard cubic foot (Btu/scf), typically varying from 950 to 1,050 Btu/scf.[a]

Natural gas is typically classified as being either conventional or unconventional, depending on the permeability of the formation (reservoir) within which it is found, the production

[a] The 1,031 Btu/scf average, also equivalent to 54.1 megajoule (MJ)/kilogram (kg), is calculated using the high heating value of natural gas at standard conditions of 60 °F and 1 atm.

technology used to secure it, the current economic environment, and the scale, frequency, and duration of production from the reservoir (EIA, 2023b; Krieg, 2018). Generally, conventional natural gas refers to natural gas found in highly permeable reservoirs, typically composed of sandstone or limestone, which allows for extraction to be completed in a relatively straightforward manner via the use of vertical rather than horizontal drilling. Unconventional natural gas refers to natural gas found within low-permeability reservoirs; generally trapped within the pores (i.e., small, unconnected spaces) of rocks, which makes extraction more difficult and necessitates the use of advanced drilling (e.g., directional, or horizontal drilling) and well stimulation (e.g., hydraulic fracturing) techniques that can be energy intensive (British Petroleum [BP], 2017).

Unconventional natural gas production has not only made up for declining conventional natural gas production but has also led to new levels of natural gas supply in the United States. This increased supply has contributed to an increase in the use of natural gas for power generation, manufacturing, transportation, and residential and commercial heating, as well as the availability of natural gas for export from the United States.

There are three primary types of unconventional natural gas:[e]

- **Shale Gas:** refers to natural gas found within shale rock formations, which consist of fine-grained sedimentary rock that forms when silt and clay-size mineral particles are compacted together (Zendehboudi and Bahadori, 2016). Shale rock formations can be easily broken into thinner, parallel layers of rock.
- **CBM:** refers to natural gas that is both generated and stored in coal beds. Originally extracted from coal mines to reduce the potential for explosions caused by an excess of CH_4 gas within the mine and subsequently disposed of, CBM now serves as an important source of energy. Producing CBM from deeper, denser coal formations often requires the use of hydraulic fracturing technology.
- **Tight Sands Gas:** refers to natural gas found in low-permeability, gas-bearing, fine-grained sandstones, or carbonates.

Today, the majority the natural gas produced domestically is unconventional and is found in shale rock formations. These formations are often referred to as “plays” and can be found in nearly 30 different U.S. states. Operators in the Barnett Shale formation, which is located in Texas and is one of the largest onshore natural gas plays in the United States, have been producing unconventional natural gas since the early 2000s (Railroad Commission of Texas [RRC], 2023).

While operators in the Barnett Shale formation still produce a significant amount of our nation’s unconventional natural gas, the Marcellus Shale formation—located in the Appalachian Region of the United States and spanning across areas in Ohio, Pennsylvania, and West

[e] There are other types of unconventional natural gas whose exploitation has not yet reached commercial scale. These include methane hydrate, which is a crystalline solid that consists of a CH_4 molecule surrounded by a cage of interlocking water molecules. Methane hydrate is an "ice" that only occurs naturally in subsurface deposits where temperature and pressure conditions are favorable for its formation.

Virginia—is currently the largest source of domestic unconventional natural gas from shale rock (EIA, 2023b).

Primary enabling technologies for accessing unconventional natural gas include hydraulic fracturing and horizontal drilling. Hydraulic fracturing (sometimes referred to as hydrofracking or simply fracking) is the process of pumping water mixed with a small amount of sand and other chemical additives (i.e., fracturing fluid) underground through a wellbore at a pressure that is sufficient to cause a target rock formation to break (i.e., fracture) (U.S. Geological Survey [USGS], 2019).[f,g] As the rock is fractured, natural gas that would have otherwise remained trapped is able to be released into a wellbore and returned to the surface (USGS, 2019).

The internal pressure caused by the fracturing of the rock formation also releases fluid, which travels to the surface through the wellbore. This fluid is commonly referred to as “flowback” or “produced water” and may contain the injected chemicals in addition to any naturally occurring materials found below the surface (e.g., brines, metals, radionuclides, and hydrocarbons). The fluid is oftentimes stored on site at the well-pad in tanks or pits before it is treated and disposed of or recycled. In many cases, disposing of the fluid involves injecting it underground. In areas where underground injection is not an option, the fluid can either be reused or processed by a wastewater treatment facility and subsequently discharged into surface water.

Hydraulic fracturing has been applied since the late 1940s when Standard Oil of Indiana (later known as Amoco) developed the technique and performed some of the first fracture treatments in the Hugoton Gas Field in Kansas (BP, 2017). While the use of hydraulic fracturing is not limited to wells that are horizontally drilled, the combination of horizontal drilling and hydraulic fracturing has increased the volume of domestic natural gas considered to be “technically recoverable” (i.e., able to be produced using currently available technology and industry practices regardless of any economic considerations).

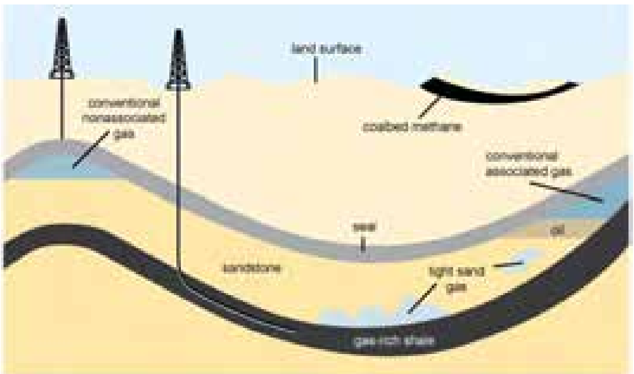
The process of horizontal drilling involves first drilling a vertical well. Once a specified depth has been reached with the vertical well, the path of drilling is bent until the well begins to extend horizontally. Horizontal wells are not only longer than vertical wells, but the process is much more complex. A horizontal well is, therefore, generally more expensive to drill than a vertical well, but it is expected to produce more natural gas (EIA, 2018). The horizontal section of a well, sometimes referred to as the directionally drilled section, can extend thousands of feet (ft).

Exhibit 1-1 provides a schematic of conventional natural gas and the various types of unconventional natural gas resources described previously (EIA, 2023b). Exhibit 1-2 provides a schematic of the combined processes of horizontal drilling and hydraulic fracturing (BP, 2017).

[f] The specific types of chemical additives used, and the proportions of each, depend on the type of rock formation that is being fractured. Additives function as friction reducers, biocides, oxygen (O_2) scavengers, stabilizers, and acids, all of which are necessary to optimize production. The composition of these fluids and the purposes of the additives are described in more detail in Chapter 4 – Water Use and Quality.

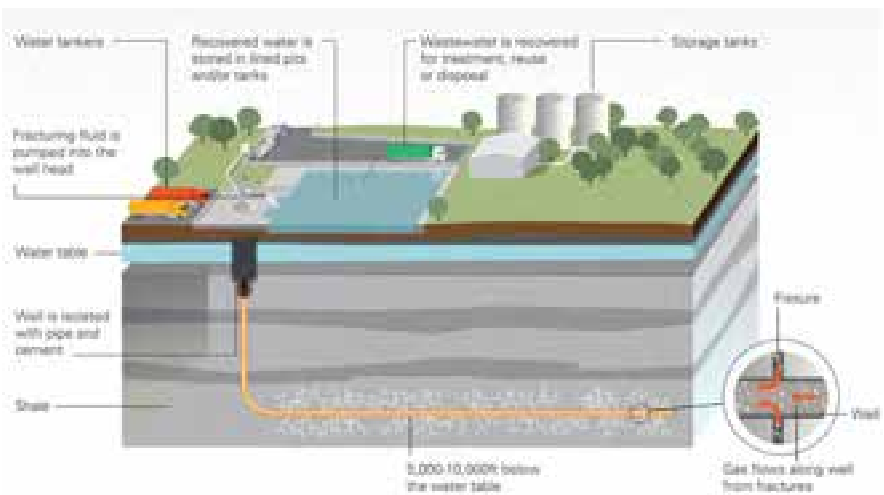
[g] In addition to enabling recovery of natural gas from unconventional resources, hydraulic fracturing techniques have also been used to produce shale oil and both natural gas and oil from conventional resources (NPC, 2011).

Exhibit 1-1. Schematic geology of natural gas resources



Source: EIA (2023b)

Exhibit 1-2. Schematic geology of natural gas resources (3D)



Permission pending from BP (2017)

1.1.1 Liquefied Natural Gas

Liquefied natural gas is natural gas that has been cooled to a liquid state (approximately -260° F or -162° C). The volume of natural gas in a liquid state is about 600 times smaller than in a gaseous state (Molnar, 2022). Liquefying natural gas is one way to allow markets that are far away from production regions, or where pipeline capacity and delivery is constrained or unavailable (e.g., New England) to access natural gas. Once in liquid form, natural gas can be shipped to terminals around the world via ocean tankers. At these terminals, the liquefied natural gas (LNG) is returned to its gaseous state and transported by pipeline to distribution companies, industrial consumers, and power plants. In some cases (over shorter distances), LNG can also be shipped by transport trailers (i.e., trucks), often to end-use facilities, where it is regasified (DOE, 2021). Liquification of natural gas not only allows for a more flexible way of transporting natural gas, but also makes it more economic to transport natural gas on a per-unit basis but only if there is a need to move the natural gas over a long distance (e.g., export natural gas to overseas markets) (Molnar 2022). Transportation typically accounts for more than half of the total costs that occur throughout the natural gas supply chain regardless of the state of the natural gas. Both pipeline and LNG transportation systems require large upfront investment costs. [h]

1.2 U.S. Natural Gas Resources

Annual U.S. production of dry natural gas was approximately 35.81 trillion cubic feet (Tcf) in 2022 (an average of about 98.11 billion cubic feet [Bcf] per day). Between 2021 and 2022, annual production of dry natural gas increased by about 4 percent from approximately 34.52 Tcf (an average of about 94.57 Bcf per day). With the exception of 2015–2016 and 2019–2020, annual domestic production of dry natural gas has increased year-over-year since 2005 as hydraulic fracturing combined with horizontal drilling has continued.

About 70 percent of the domestic dry natural gas production in 2021 was supplied by five of the United States' 34 natural gas-producing states.[i] States with a larger percentage share of total U.S. dry natural gas production in 2021 include Texas (24.6 percent), Pennsylvania (21.8 percent), Louisiana (9.9 percent), West Virginia (7.4 percent), and Oklahoma (6.7 percent) (Exhibit 1-3) (EIA, 2023b).

Exhibit 1-3. U.S. natural gas production by state in 2021

Source: EIA (2023b)

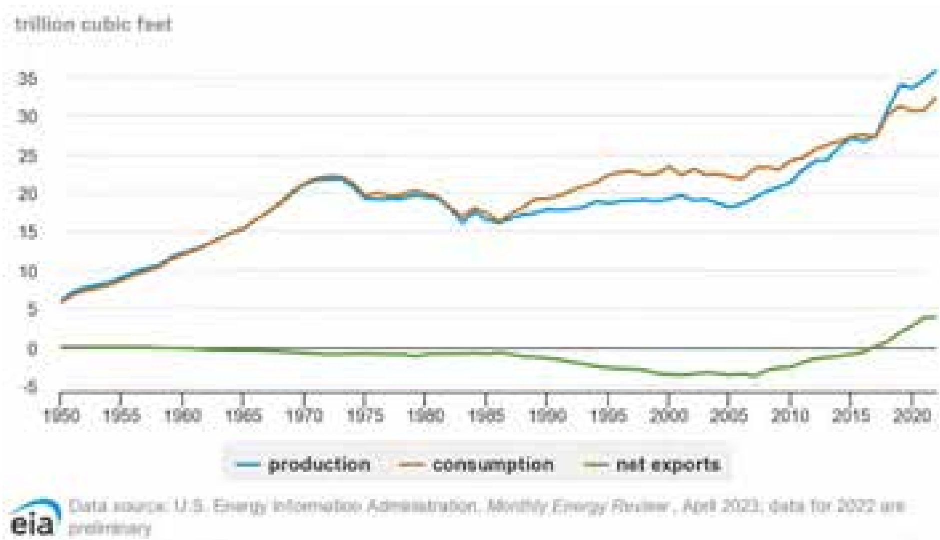
[h] LNG becomes cost-competitive with pipeline transportation once the distance the natural gas needs to travel exceeds 1,000 kilometers (km).

[i] 2022 state-level data was not available at the time this report was written. As such, 2021 state-level data is used above.

In 2022, tight sands natural gas and natural gas from shale collectively accounted for 31.62 Tcf of dry natural gas produced onshore in the lower-48 states. In the same year, 3.43 Tcf of the dry-natural gas produced on-shore was supplied by CBM (EIA, 2023b). Although most of the natural gas wells operated by the United States are located onshore, some wells are drilled offshore (i.e., into the ocean floor in waters off the coast of the United States). In 2022, offshore dry natural gas production was approximately equal to 0.80 Tcf, accounting for about 2.3 percent of total production. The majority—87.6 percent—of this production occurred in federally managed waters within the Gulf of Mexico (EIA, 2023b).

In addition to being a producer of natural gas, the United States is also a consumer and net exporter of natural gas. In 2022, the United States produced about 10.8 percent more natural gas than it consumed—on a net basis, the United States was a net exporter of natural gas. Exhibit 1-4 highlights recent (2022) and historical (1950–2021) U.S. natural gas production, consumption, and net exports (EIA, 2023a).

Exhibit 1-4. U.S. natural gas consumption, dry production, and net exports (1950–2022)



Source: EIA (2023a)

1.3 U.S. Regulatory Framework

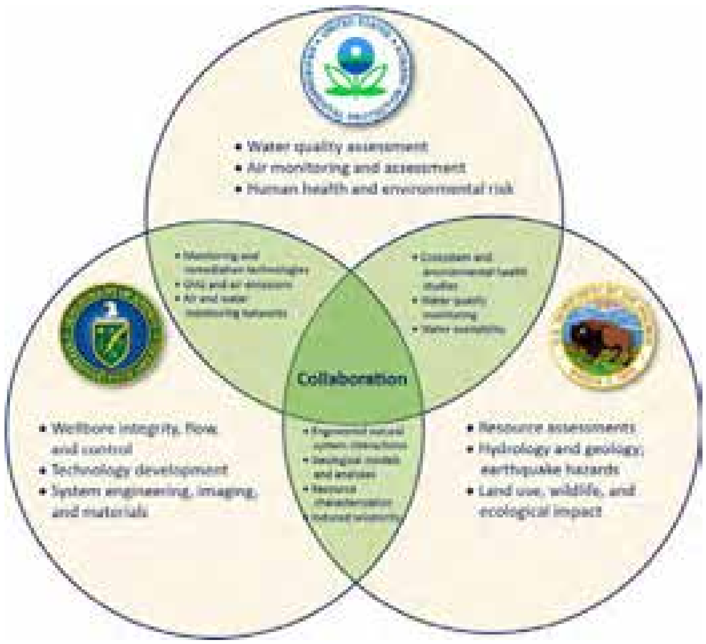
The following sub-sections provide a review of both federal and state regulatory responsibilities related to the production, transportation, use, and export of domestic natural gas resources.

1.3.1 Federal

Multiple federal agencies have authority over the production of natural gas resources. Three of these agencies—DOE, the Department of the Interior (DOI), and the Environmental Protection

Agency (EPA)—play a uniquely critical role as they are charged with monitoring, assessing, and reporting on various natural gas environmental impacts, such as those described in this report. Exhibit 1-5 describes the roles and responsibilities of these three agencies at a high-level in addition to the way they work together to inform policy-relevant science.

Exhibit 1-5. Key U.S. agencies and their roles in natural gas development and production



Source: DOE

The following subsections detail some of the specific roles and responsibilities of these agencies and, where applicable, their specific bureaus and offices. Exhibit 1-6 provides examples of the federal statutes applicable to unconventional natural gas development helping to guide the roles and responsibilities described.

Exhibit 1-6. Selected federal regulations that apply to unconventional oil and gas development

Statutes	Applicability
Clean Air Act (CAA)	Places requirements on air emissions from sources of emissions at well sites; addresses compliance with existing and new air regulations, often delegated to local and state agencies. Generally, there is no distinction made between conventional and unconventional wells under the CAA.
Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA)	Only applies if hazardous substances besides crude oil or natural gas are released in quantities that require reporting. Natural gas releases do not require notification under the Comprehensive Environmental Response, Compensation, and Liability Act, but other hazardous substances may be released in reportable quantities during natural gas production.
Clean Water Act (CWA)	Limits pollutants on produced water discharge under the National Pollutant Discharge Elimination System; stormwater runoff containing sediment that would cause a water-quality violation requires a permit under CWA decisions. Beneficial uses of surface waters are protected under Section 303.
Emergency Planning and Community Right-to-Know Act (EPCRA)	Requires facilities storing hazardous chemicals above the threshold to report same and provide a Material Safety Data Sheet to officials and fire departments.
Endangered Species Act (ESA)	Prohibits federal agencies from taking any action that is likely to jeopardize the continued existence of any endangered or threatened species (listed species) or result in the destruction or adverse modification of such species' designated critical habitat (Section 7); prohibits the taking of a listed species (Section 9); allows the Fish and Wildlife Service and National Marine Fisheries Service to issue a permit, accompanied by an approved habitat conservation plan, that allows for the incidental, non-purposeful "take" of a listed species under their jurisdictions (Section 10).
National Environmental Policy Act (NEPA)	Requires analysis of potential environmental impacts of proposed federal actions, such as approvals for exploration and production on federal lands.
Oil Pollution Act (OPA)	Identifies spill prevention requirements, reporting obligations, and response planning (measures that will be implemented in the case of release of oil or other hazardous substances).
Resource Conservation and Recovery Act (RCRA)	Addresses non-hazardous solid wastes under Subtitle D. The Solid Waste Disposal Act exempts many wastes produced during the development of natural gas resources, including drilling fluids and produced water. EPA determined that other federal and state regulations are more effective at protecting health and the environment.
Safe Drinking Water Act (SDWA)	Prevents the injection of liquid waste into underground drinking water sources through the Underground Injection Control (UIC) program. Fluids other than diesel fuel do not require a UIC permit. The UIC program gives requirements for siting, construction, operation, closure, and financial responsibility. Forty states control their own UIC programs.

1.3.1.1 Department of Interior

The DOI is a cabinet-level agency that manages America's vast natural and cultural resources through the operations of 11 technical bureaus. Of the DOI's bureaus, the Bureau of Land

Management (BLM), the National Park Service (NPS), and the U.S. Forest Service (USFS) each have responsibilities related to the enforcement of regulations for natural gas and oil wells drilled on public lands.

1.3.1.1.1 Bureau of Land Management

The BLM manages the U.S. government's onshore subsurface mineral estate—an area of about 700 million (MM) acres—from which sales of oil, gas, and natural gas liquids accounted for approximately 11 percent of all oil and 9 percent of all natural gas produced in the United States during fiscal year 2022.[j,k] About 23 of these 700 MM acres were leased to natural gas developers by the end of that year, and about 12.4 MM of those acres were producing natural gas in economic quantities (BLM, 2023).

From regulatory perspective, the BLM is responsible for 1) ensuring the environment of public lands remains protected and unaffected by natural gas production and other related activities and 2) managing natural gas development on federally owned lands. BLM published a rule regulating natural gas fracking on public lands on March 26, 2015—this rule was rescinded on December 28, 2017 (Fitterman, 2021).

On November 30, 2022, BLM proposed new regulations to reduce the waste of natural gas from venting, flaring, and leaks during oil and gas production activities on Federal and Indian leases (BLM, 2022). Key elements of the proposed rule include the following:

- Technology Upgrades: The rule would require the use of "low-bleed" pneumatic equipment as well as vapor recovery for oil storage tanks, where economically feasible. These requirements would reduce losses of natural gas from pneumatic equipment and storage tanks on federal and Indian leases.
- Leak Detection Plans: The rule would require operators to maintain a Leak Detection and Repair program for their operations on federal and Indian leases.
- Waste Minimization Plans: Requires the development of waste minimization plans demonstrating the capacity of available pipeline infrastructure to take the anticipated associated gas production. The BLM may delay action on, or ultimately deny, a permit to drill to avoid excessive flaring of associated gas.
- Monthly Limits on Flaring: Places time and volume limits on royalty-free flaring. Importantly, this includes a monthly volume limit on royalty-free flaring due to pipeline capacity constraints—the primary cause of flaring from Federal and Indian leases.

Drilling on federal or public lands is subject to oversight by federal agencies, and sections of the ESA may require that species of plants or animals not be threatened by the permitted drill site. Mandatory plans for mitigation and reclamation may be required to ensure that impacts on wildlife and habitat will be as minimal as possible.

[j] This area is held jointly by the BLM, USFS, and other federal agencies and surface owners.
[k] October 1, 2021, through September 30, 2022.

1.3.1.1.2 U.S. Forest Service

The USFS is responsible for managing access to, and the development of, federal oil and natural gas resources on approximately one-third of the over 150 national forests and grasslands. The Federal Onshore Oil and Gas Leasing Reform Act of 1987 grants the USFS authority to decide if the lands reserved from the public's domain can be leased for oil and gas development.[l] The USFS manages oil and gas activity according to the regulations at 36 CFR 228 Subpart E (USFS, 2023a). The purpose of these specific regulations is to set forth rules and procedures through which use of the federal surface lands in connection with operations authorized by the United States mining laws shall be conducted so as to minimize adverse environmental impacts.

1.3.1.1.3 National Park Service

Natural gas production and other related activities that will or do take place within the boundaries of America's national parks are managed by the NPS. Charged with protecting park resources and visitor values, the NPS helps to manage oil and gas operations following the 9B regulations. This set of regulations governs non-federal oil and gas activities and producing a final Environmental Impact Statement (EIS) for units of the national park system where oil and gas production occurs, or is likely to occur, in the foreseeable future (NPS, 2023).

1.3.1.2 Environmental Protection Agency

EPA is charged with regulating the air emissions covered under the CAA. EPA regulates several types of emissions relevant to the natural gas supply chain, including CH_4 emissions, criteria air pollutant emissions, and water and soil pollutants. EPA's New Source Performance Standards (NSPS) under the CAA set the regulations for emissions sources from the oil and natural gas sector. Exhibit 1-7 illustrates the scope of NSPS established or proposed to-date and the way regulations have evolved in scope since 2012 (EPA, 2021).

[l] Lands reserved from the public's domain include lands that have been withdrawn or reserved for use as part of the National Forests or National Grasslands or received in exchange for the same status of land (USFS, 2023b).

Exhibit 1-7. Natural gas sources covered by EPA's proposed NSPS and emissions guidelines, by site

Location and Equipment or Process Covered	Required to or Would Be Required to Reduce Emissions under EPA Rules (if finalized as proposed)	Rules that Apply			
		2012 NSPS for VOCs (OOOO)	2016 NSPS for Methane & VOCs (OOOOa)	2021 Proposed NSPS for Methane & VOCs (OOOOb)	2021 Proposed Emission Guidelines for Methane (OOOOc)
Oil and Natural Gas Well Sites					
Completions of hydraulically fractured wells	✓	•	•	•	
Compressors at centralized tank batteries	✓			•	•
Fugitive emissions	✓		•	•	•
Liquids unloading	✓			•	
Pneumatic controllers	✓	•	•	•	•
Pneumatic pumps	✓		•	•	•
Storage vessels	✓	•	•[2]	•	•
Sweetening units	✓	•[1]	•[1]	•[1]	•[1]
Associated gas from oil wells	✓			•	•
Natural Gas Gathering and Boosting Compressor Stations					
Compressors	✓	•	•	•	•
Fugitive emissions	✓		•	•	•
Pneumatic controllers	✓	•	•	•	•
Pneumatic pumps	✓			•	•
Storage vessels	✓	•	•[2]	•	•
Sweetening units	✓	•[1]	•[1]	•[1]	•[1]
Natural Gas Processing Segment					
Compressors	✓	•	•	•	•
Fugitive emissions	✓	•		•	•
Pneumatic controllers	✓	•	•	•	•
Pneumatic pumps	✓		•	•	•
Storage vessels	✓	•	•[2]	•	•
Sweetening units	✓	•[1]	•[1]	•[1]	•[1]
Transmission and Storage Segment					
Compressors	✓		•	•	•
Fugitive emissions	✓		•	•	•
Pneumatic controllers	✓		•	•	•
Pneumatic pumps	✓			•	•
Storage vessels	✓	•	•[2]	•	•

[1]Covered for sulfur dioxide only; [2]Covered for volatile organic compounds only

Source: EPA (2021)

Following an initial proposal in November 2021, on December 6, 2022, EPA issued a supplemental proposal to update, strengthen, and expand standards intended to significantly reduce emissions of GHG and other harmful air pollutants from the Crude Oil and Natural Gas source category (EPA, 2022a). First, EPA proposed standards for certain sources that were not previously addressed. Second, EPA proposed revisions that strengthen standards for sources of leaks, provide greater flexibility to use innovative advanced detection methods, and establish a super-emitter response program. Third, EPA proposed to modify and refine certain elements of the proposed standards in response to information submitted in public comments. Finally, EPA proposed details of the timelines and other implementation requirements that apply to states to limit CH_4 pollution from existing designated facilities in the source category under the CAA (EPA, 2022a). Evaluation of this proposed rule is still in progress.

EPA's Greenhouse Gas Reporting Program (GHGRP) requires reporting of GHG emissions data and other relevant information by large sources of emissions, including fuel and industrial gas suppliers and CO_2 injection sites (EPA, 2023). The data reported is available to businesses, stakeholders, and others interested in tracking and comparing the GHG emissions of facilities, identifying opportunities to reduce emissions, minimizing wasted energy, and saving money. The petroleum and natural gas industry is covered under Subpart W of EPA's GHGRP. Unconventional natural gas production is covered under the provisions for onshore production, natural gas processing, natural gas transmission, and LNG storage and import/export. Annual CO_2, CH_4, and nitrogen oxides (NOx) emissions must be reported separately for each of these segments.

EPA studied the relationship between hydraulic fracturing for oil and natural gas and drinking water resources (EPA, 2022b). The study includes a review of published literature, analysis of existing data, scenario evaluation and modeling, laboratory studies, and case studies. EPA released a progress report in December 2012, a final draft assessment report for peer review and comment in June 2015, and the final report in December 2016. The final EPA report concludes that hydraulic fracturing activities can impact drinking water resources under some circumstances and identifies factors that influence these impacts.

Under the SDWA, EPA is charged with developing the minimum federal requirements for injection well practices to protect the public's health and prevent the contamination of underground sources of drinking water. A core element of the SDWA UIC program is setting requirements for proper well siting, construction, and operation to minimize risks to underground sources of drinking water. The Energy Policy Act of 2005 excluded hydraulic fracturing (except when diesel fuels are used) for oil, natural gas, or geothermal production from regulation under the UIC program. This statutory language caused regulators and the regulated community alike to raise questions about the applicability of permitting practices. As a result, EPA developed revised UIC Class II permitting guidance specific to oil and natural gas hydraulic fracturing activities using diesel fuels (EPA, 2022b). Although developed specifically for hydraulic fracturing where diesel fuels are used, many of the guidance's recommended practices are consistent with best practices for hydraulic fracturing in general, including those found in state regulations and model guidelines for hydraulic fracturing developed by industry and stakeholders. Thus, states and tribes responsible for issuing permits and/or updating regulations for hydraulic fracturing will find the recommendations useful in improving the protection of underground sources of drinking water and public health in general wherever hydraulic fracturing occurs. The guidance outlines for EPA permit writers, where they are the permitting authority, 1) existing Class II requirements for diesel fuels used for hydraulic fracturing of wells, and 2) technical recommendations for permitting those wells consistently with these requirements (EPA, 2022b).

EPA completed a stakeholder engagement effort in 2019 that sought input on how the agency, states, tribes, and stakeholders regulate and manage wastewater from the oil and gas industry. EPA released a draft report in May 2019 that described what it heard during its engagement for this study (EPA, 2022b). EPA accepted public input on the draft report and, after considering this input, published a final report in May 2020 (EPA, 2020). In many regions of the United States, underground injection is the most common method of managing fluids or other substances from shale gas extraction operations. Management of flowback and produced water via underground injection is regulated under the SDWA UIC program. The CWA effluent guidelines program sets national standards for industrial wastewater discharge to surface waters and municipal sewage treatment plants based on the performance of treatment and control technologies. Effluent guidelines for onshore oil and natural gas extraction facilities prohibit the discharge of pollutants into surface waters, although some permit exceptions may allow for discharge under unique conditions. On June 28, 2016, EPA promulgated pretreatment standards for the Oil and Gas Extraction Category (40 CFR Part 435). These regulations prohibit discharge of wastewater pollutants from onshore unconventional oil and natural gas extraction facilities to publicly owned treatment works (POTWs).[m]

1.3.1.3 Department of Energy

The Natural Gas Act (NGA) requires DOE to make public interest determinations on applications to export LNG to countries where the United States does not have existing free trade agreements requiring national treatment for trade in natural gas. The Office of Fossil Energy and Carbon Management's (FECM) natural gas import–export regulatory program is implemented by the Division of Regulation in the Office of Regulation, Analysis, and Engagement. Typically, the Federal Energy Regulatory Commission (FERC) has direct regulatory responsibility over the siting, construction, and operation of onshore LNG export facilities in the United States. In these cases, FERC leads the environmental impact assessments of proposed projects consistent with NEPA, and DOE is typically a cooperating agency as part of these reviews (DOE, 2023a). Similarly, for offshore LNG export facilities, the Department of Transportation's (DOT) Maritime Administration (MARAD) is responsible for environmental reviews, in coordination with the U.S. Coast Guard, guided by requirements in the Deepwater Port Act. Again, DOE is typically a cooperating agency in these reviews. In some limited circumstances, DOE is the lead agency for NEPA reviews related to proposed LNG exports.

FECM's Point Source Carbon Capture Division's research, development, demonstration, and deployment portfolio facilitates the development of technologies and infrastructure that improve performance, reduce costs, and scale the deployment of technologies to decarbonize the industrial and power sectors and remove CO_2 from the atmosphere. Within the natural gas supply chain, these efforts include research and commercial-scale demonstration of technologies that advance carbon capture and storage on natural gas-fired power plants and industrial natural gas combustion streams (DOE, 2023a).

FECM is working to support efforts to decarbonize LNG terminals through exploration of technical and economic feasibility of carbon capture on gas separation and combustion streams and the use of electric motor drives supplied by net-zero emissions electricity. Decarbonizing LNG terminals is a key part of the effort to reduce life cycle emissions associated with the export of natural gas to global allies.

FECM's Methane Mitigation Technologies Division aims to eliminate non-trivial fugitive and vented CH_4 emissions from the natural gas supply chain to reduce the climate impacts from the production and use of natural gas. The division is focused on developing accurate, cost effective, and efficient technology solutions and best practices to identify, measure, monitor, and minimize CH_4 emissions from these sources. DOE funded several technology investigations through NETL that deal with produced water management and life cycle assessments of the natural gas value chain (DOE, 2023b). NETL's Natural Gas Infrastructure Field Work Proposal aims to strengthen natural gas pipeline reliability and reduce emissions on two fronts: quantifying GHG emissions and developing material and sensor technologies that will help to

[m] "Publicly owned treatment works" is a term used in the United States to designate a sewage treatment plant owned, and usually operated, by a government agency. In the United States, POTWs are typically owned by local government agencies and are usually designed to treat domestic sewage and not industrial wastewater.

mitigate these emissions. Research in this Field Work Proposal will also help address the reliability, public safety, operational efficiency, and flexibility of the America's aging natural gas infrastructure.

DOE's shale gas research program brings together federal and state agencies, industry, academia, non-governmental organizations (NGOs), and national laboratories to develop technologies that enable safe, environmentally sustainable oil and gas production. DOE's shale gas research program is tasked with calculating the risks of oil and gas exploration and production undertakings.

On April 21, 2023, a Request for Information (RFI) was issued by FECM to obtain input to inform DOE's research and development (R&D) activities within the Office of Research and Development's Methane Mitigation Technologies Division and the Office of Carbon Management Technologies' Point Source Carbon Capture Division. In addition, such data and information could help inform the Office of Regulation, Analysis, and Engagement's capabilities to assess natural gas import and/or export applications. Through the RFI, DOE requested information on strategies and technologies that natural gas and LNG companies are deploying, or could deploy, to reduce GHG emissions and other air pollutants associated with natural gas delivered to liquefaction facilities, housed at liquefaction facilities, and being loaded, transported, and delivered to regasification facilities (DOE, 2023a).

1.3.1.4 Occupational Safety and Health

The Occupational Safety and Health Administration (OSHA) establishes standards, directives (instruction to OSHA staff), letters of interpretation, and national consensus standards that pertain to employee safety within the oil and gas extraction industry (OSHA, 2023). OSHA standards are in place to limit employee exposures to hazards present during oil and gas well drilling, servicing, and storage. Regulations and standards related to site preparation activities, which include leveling the site, trenching, and excavation, are covered under 29 CFR 1926, while all other aspects drilling and servicing operations are covered by 29 CFR 1910 (OSHA, 2023).

1.3.2 States

States have the power to implement their own requirements and regulations for natural gas drilling that are equivalent to or more stringent than established federal practices.[n] All states that produce natural gas have at least one agency charged with issuing new permits for production wells. While state requirements for permits can differ, any requirements set forth by federal regulations must be met for a state-level permit to be issued. Beyond issuing new permits for production, states can also issue regulatory requirements for managing the potential environmental impacts of natural gas activities.

Although regulations, rules, and restrictions vary by state, in some cases, the actions taken by one or a subset of states have helped to both inform similar regulations imposed by other

[n] Zirogiannis et al. (2016) developed a framework for comparing states based on how intensely they regulate unconventional gas development.

states and further refine some federal rules. A number of states, including Colorado, New Mexico, and Pennsylvania have adopted regulations to help manage GHG emissions including CH_4 and other air pollutants (e.g., volatile organic compounds) from oil and natural gas operations (Commonwealth of Pennsylvania, 2023b). Colorado, in particular, is also in the process of developing a rule focused on verifying GHG emissions intensity reporting (Colorado Department of Public Health & Environment, 2023).

In Oklahoma, using existing regulatory authorities, state regulators are expanding their technical guidance to inform operator efforts to sustainably manage produced water while reducing incidences of induced seismicity. For example, Oklahoma authorities have systemically identified areas of seismic concern and are 1) focusing resources where induced seismicity has previously occurred due to underground fluid injection activities, and 2) implementing new protocols for hydraulic fracturing, well completion, and wastewater disposal underground (Skinner 2018). As for land use and development considerations, there are permissible noise levels embodied in regulations that gas operators across Colorado must adhere to. For example, drilling, well stimulation and completion, as well as workovers, are now held to maximum permissible noise level standards for industrial zones.

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2 Greenhouse Gas Emissions

The primary GHG emissions associated with the natural gas supply chain steps of production through transport are emissions of CO_2 and CH_4. CO_2 emissions are primarily the result of fossil fuel combustion which is done to power equipment and operations. CH_4 emissions are the result of intentional and unintentional releases of natural gas as it moves through the supply chain. CH_4 is the primary component of natural gas. CO_2 and CH_4 emissions vary significantly across different regions and supply chains depending on the composition of the natural gas that is being produced, the type of equipment being used to process and transport the natural gas, and the number and size of intentional and unintentional releases of the natural gas.

2.1 Overview of GHG Emissions

The U.S. natural gas system encompasses hundreds of thousands of wells, hundreds of processing facilities, and over 1 MM miles of transmission and distribution pipelines. The EPA develops an annual report - the "Inventory of U.S. Greenhouse Gas Emissions and Sinks" – which tracks domestic GHG emissions and sinks by source and economic sector going back to 1990 (EPA, 2023a). The inventory (report) was last released in April 2023 and provided annual estimates up to the year 2021 (EPA, 2023a). Contained within the EPA's GHG Emissions Inventory (hereafter, GHGI) are annual estimates of the GHG emissions including CH_4, associated with natural gas systems.

EPA's April 2023 release of the GHGI suggested total GHG emissions (including CH_4, CO_2, and nitrous oxide [N_2O]) from natural gas systems in 2021 were 217.5 MM metric tons (MMT) of carbon dioxide equivalent (CO_2e), a decrease of 12 percent from 1990 and a decrease of 2 percent from 2020, both primarily due to decreases in CH_4 emissions. From 2010, emissions decreased by 3 percent, primarily due to decreases in CH_4 emissions. Of the overall GHG emissions (217.5 MMT CO_2e), 83 percent are CH_4 emissions (181.4 MMT CO_2e), 17 percent are CO_2 emissions (36.2 MMT CO_2e), and less than 0.01 percent are N_2O emissions (0.01 MMT CO_2e). Exhibit 2-1 shows estimates of one GHG emission - CH_4 - by segment of the natural gas system (exploration through distribution) as reported by the GHGI.

Exhibit 2-1. EPA GHGI CH_4 emissions from natural gas systems (kiloton)

Segment	1990	2005	2017	2018	2019	2020	2021
Exploration	119	358	49	94	75	9	7
Production	2,311	3,495	3,697	3,823	3,739	3,475	3,360
Onshore Production	1,403	2,464	2,139	2,246	2,122	1,923	1,787
Gathering and Boosting	739	958	1,533	1,547	1,591	1,520	1,548
Offshore Production	170	73	26	30	25	32	24
Processing	853	463	460	483	506	495	510
Transmission and Storage	2,288	1,580	1,460	1,538	1,583	1,625	1,590
Distribution	1,819	1,018	561	557	554	553	548
Post-Meter	290	344	424	445	457	463	463

Commented [SM3]: This GHGI is an annual effort by EPA, this was just the latest version (31st version, so to speak). Also, GHGRP (mentioned in Chapter 1) plays a key role in the results represented.

SORRY, I see a few sentences later it says its annual - might want to move that up here before the April 2023 reference..

Commented [SM4R3]: One small note - they update the method for GHGI (and esp NG systems) alot. I am unsure whether they "redo past estimates" from newer methods. Point is, the raw GHG totals for the NG system may or may not be a good reference. Second point, the intensity is really what matters - if we believe EPA values, the intensity (emissions/MJ) are WAYYY lower than 1990.

Commented [HSAJSR3]: Note for FECM/HQ - We've addressed Scott's first comment here but I want to leave this in just in case you'd like us to footnote the observation in his second comment, as it seems pretty important and determines whether we can compare estimates from year to year, and also to gather your thoughts on intensity estimates.

Total	**7,680**	**7,260**	**6,652**	**6,939**	**6,914**	**6,619**	**6,478**

Note: To enable results comparison across exhibits, it is important to note the following conversion: 1,000 kiloton of CH_4 is equal to 1 Tg of CH_4.

The global warming potential (GWP) metric was developed to allow comparisons of the global warming impacts of different GHG emissions (e.g., CH_4, CO_2, and N_2O). Specifically, it is a measure of how much energy the emissions of 1 ton of a specific GHG will absorb over a given period, relative to the emissions of 1 ton of CO_2. The larger the GWP, the more that a given gas warms the Earth compared to CO_2 over that period. The period usually used for GWPs is 100 years. GWPs provide a common unit of measure, which allows analysts to add up emissions estimates of different gases (e.g., to compile a national GHG inventory), and allows policymakers to compare emissions reduction opportunities across sectors and gases (EPA, 2023b):

- CO_2, by definition, has a GWP of 1 regardless of the period used, because it is the gas being used as the reference. CO_2 remains in the climate system for a very long time: CO_2 emissions cause increases in atmospheric concentrations of CO_2 that will last thousands of years.
- CH_4 is estimated to have a GWP of 27–30 over 100 years. CH_4 emitted today lasts about a decade on average, which is much less time than CO_2. But CH_4 also absorbs much more energy than CO_2. The net effect of the shorter lifetime and higher energy absorption is reflected in the GWP. The CH_4 GWP also accounts for some indirect effects, such as the fact that CH_4 is a precursor to ozone, and ozone is itself a GHG.
- N_2O has a GWP 273 times that of CO_2 for a 100-year timescale. N_2O emitted today remains in the atmosphere for more than 100 years, on average.
- Chlorofluorocarbons, hydrofluorocarbons, hydrochlorofluorocarbons, perfluorocarbons, and sulfur hexafluoride are sometimes called high-GWP gases because, for a given amount of mass, they trap substantially more heat than CO_2. (The GWPs for these gases can be in the thousands or tens of thousands.)

Based on a review of the science of climate change, the Intergovernmental Panel on Climate Change (IPCC) estimated the GWP for CH_4 to be 36 over a 100-year period and 87 over a 20-year period in their Fifth Assessment Report (AR5) published in 2014 (IPCC, 2014). In the IPCC's Sixth Assessment Report (published in 2021), the IPCC revised the GWP estimates of CH_4 to be 29.8 over a 100-year horizon and 82.5 over a 20-year time horizon (IPCC, 2021). It is important to consider which GWP is used when reviewing the outputs of an analysis of GHG emissions, particularly when comparing the outputs of two or more analyses.

2.2 Sources of GHG Emissions

To account for all sources of GHG emissions in the natural gas supply chain, and to evaluate their relative contributions and mitigation opportunities, a systems-level perspective is both necessary and preferred. Life cycle analysis (LCA) is one type of systems-level approach available to account for the different sources of GHG emissions in the natural gas supply chain.

LCA specifically considers the material and energy flows of an entire system "from cradle to grave"—where "cradle" refers to the extraction of resources from the earth, and "grave" refers to the final use and disposition of all products. The two relevant standards for LCA are International Organization for Standardization (ISO) 14040 and ISO 14044. ISO 14040 describes the principles and framework for LCA, and ISO 14044 specifies requirements and provides guidelines for LCA.

Depending on the type of LCA conducted, different system boundaries can be put in place to more accurately estimate the GHG emissions associated with natural gas. Generally, GHG emissions occur from the beginning of the natural gas supply chain (during exploration) through the end (during utilization). In some cases, an LCA may not be able to consider every step of the natural gas supply chain within its analysis framework. This can happen for a variety of reasons, including lack of emissions data for a particular step or set of steps, or to focus specifically on the emissions associated with one particular step. Exhibit 2-2 provides an illustration of the natural gas supply chain with examples of key emissions sources.

NETL has used LCA to calculate the environmental impacts of natural gas production and use for the generation of electric power for nearly a decade (NETL, 2023). NETL's work was documented in a series of reports produced between 2010 and 2019.[a] Together, these reports provide in-depth assessments of the potential GHG emissions resulting from upstream unconventional natural gas production in the United States (NETL, 2019a). In addition to characterizing domestic upstream natural gas, NETL also developed life cycle data for exported LNG, including the GHG emissions from liquefaction, loading/unloading, ocean transport, regasification, and combustion for electricity generation (NETL, 2019b).

Commented [SM6]: Just noting that we are finalizing (2023 pub date) an updated analysis for the year 2020, and are using it in the LNG Analysis side (Task 3) of the project.

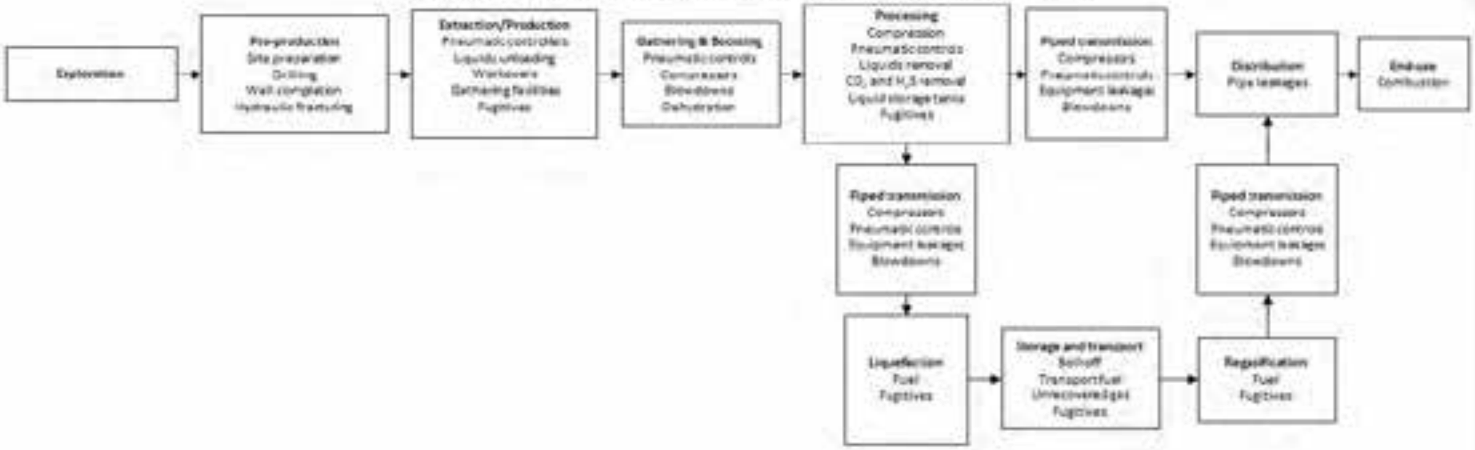
Commented [SM7R6]: Should there be a move to update this chapter based on it, it would be pretty easy. Numbers are in same places and format as in the 2019 report. Main differences are like the key emissions sources, etc.

Commented [SM8R6]: Regardless we could easily help.

Commented [HSAJ9R6]: Note for FECM- HQ: Also leaving this here for your consideration.

[a] The GHG results in the NETL (2019a) report supersede the GHG results in the previous NETL reports.

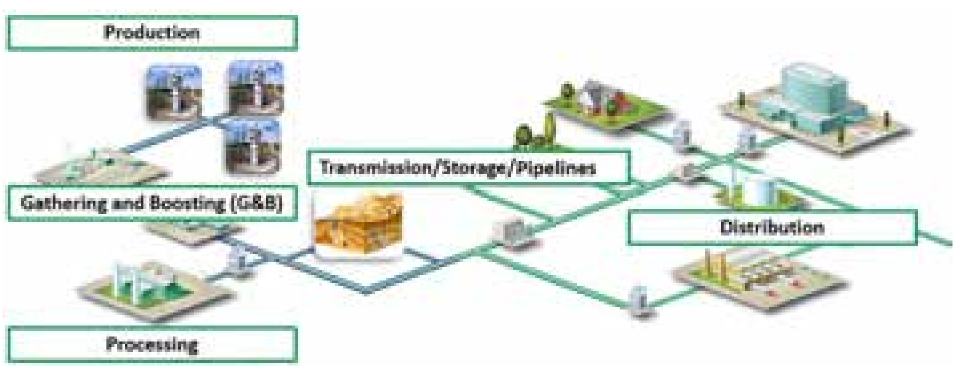
Exhibit 2-2. Natural gas supply chain with examples of key emissions sources



The GHG emissions results reported in past NETL natural gas LCAs consider five stages of the natural gas supply chain, which are visualized in Exhibit 2-3 (NETL, 2019a):

1. **Production:** Sources of emissions include the gas vented from pneumatically controlled devices and fugitive emissions from flanges, connectors, open-ended lines, and valves. When vapor recovery units are feasible, vented gas is captured and flared; otherwise, vented gas is released to the atmosphere. Production operations also include the combustion of natural gas and diesel in compressors and other equipment.
2. **Gathering and Boosting (G&B):** Natural gas G&B networks receive natural gas from multiple wells and transport it to multiple facilities. G&B sites include acid gas removal, dehydration, compressors operations, pneumatic devices, and pumps.
3. **Processing:** A natural gas processing facility removes impurities from natural gas, which improves its heating value and prepares it for pipeline transmission. Natural gas processing facilities include acid gas removal, dehydration, hydrocarbon liquids removal, and compression operations.
4. **Transmission Stations, Storage Facilities, and Transmission Pipelines:** A natural gas transmission system is a network of large pipelines that transport natural gas from processing facilities to the city gate (the point at which natural gas can be consumed by large-scale consumers or transferred to local distribution companies). Transmission stations are located along natural gas transmission pipelines and use compressors to boost the pressure of the natural gas. Large industrial users typically access natural gas directly from transmission pipelines.
5. **Distribution:** Natural gas distribution networks transport natural gas from the city gate to commercial, residential, and some industrial consumers. This analysis uses the distribution portion of the supply chain only for the upstream functional unit; distribution is not necessary for the functional unit of electricity in which natural gas power plants receive natural gas directly from transmission pipelines.

Exhibit 2-3. Supply chain stages that compose the overall LCA boundary



The flexible, consistent framework of NETL's LCA model allows different natural gas sources to be compared on a common basis (per MJ of delivered natural gas). In the NETL (2019a) report, five types of natural gas are considered:

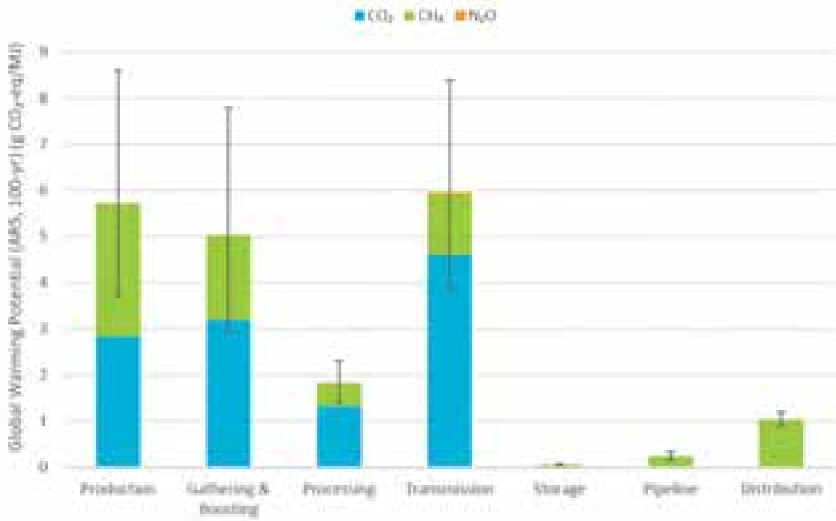
1. **Conventional natural gas** is natural gas extracted via vertical wells in high permeability formations that generally do not require, but can in some cases benefit from, stimulation technologies (e.g., hydraulic fracturing) for primary production.
2. **CBM** is extracted from coal seams and requires the removal of naturally occurring water from the seam before natural gas wells are productive.
3. **Shale gas** is extracted from low permeability formations and requires hydraulic fracturing and horizontal drilling.
4. **Tight gas** is extracted from non-shale, low permeability formations and requires hydraulic fracturing and directional drilling.
5. **Associated gas** is found with petroleum (either dissolved in oil or in a gas cap in a petroleum formation) and is produced by oil wells.

In the 2019 LCA analysis of the natural gas supply chain, NETL used the GWP reported in the IPCC AR5 (NETL, 2019a). Results from the 2019 NETL LCA analysis performed suggested the following (NETL, 2019a):

- The life cycle GHG emissions associated with the U.S. natural gas supply chain were 19.9 grams (g) of CO_2e per MJ of natural gas delivered (with a 95 percent mean confidence interval of 13.1–28.7 g CO_2e per MJ). The boundary used in this study was natural gas production through transmission to large end-users.
- The top contributors to CO_2 and CH_4 emissions were combustion exhaust and other venting from compressor systems. Compressor systems are prevalent in most stages of the natural gas supply chain and as such were key contributors to the total life cycle emissions estimated.
- Emissions rates are highly variable across the entire supply chain. According to the study, the national average CH_4 emissions rate was 1.24 percent, with a 95 percent mean confidence interval ranging 0.84–1.76 percent.

Exhibit 2-4 shows the GHG emissions from the different parts of the natural gas supply chain (NETL, 2019a).

Exhibit 2-4. Life cycle GHG emissions for the U.S. natural gas supply chain



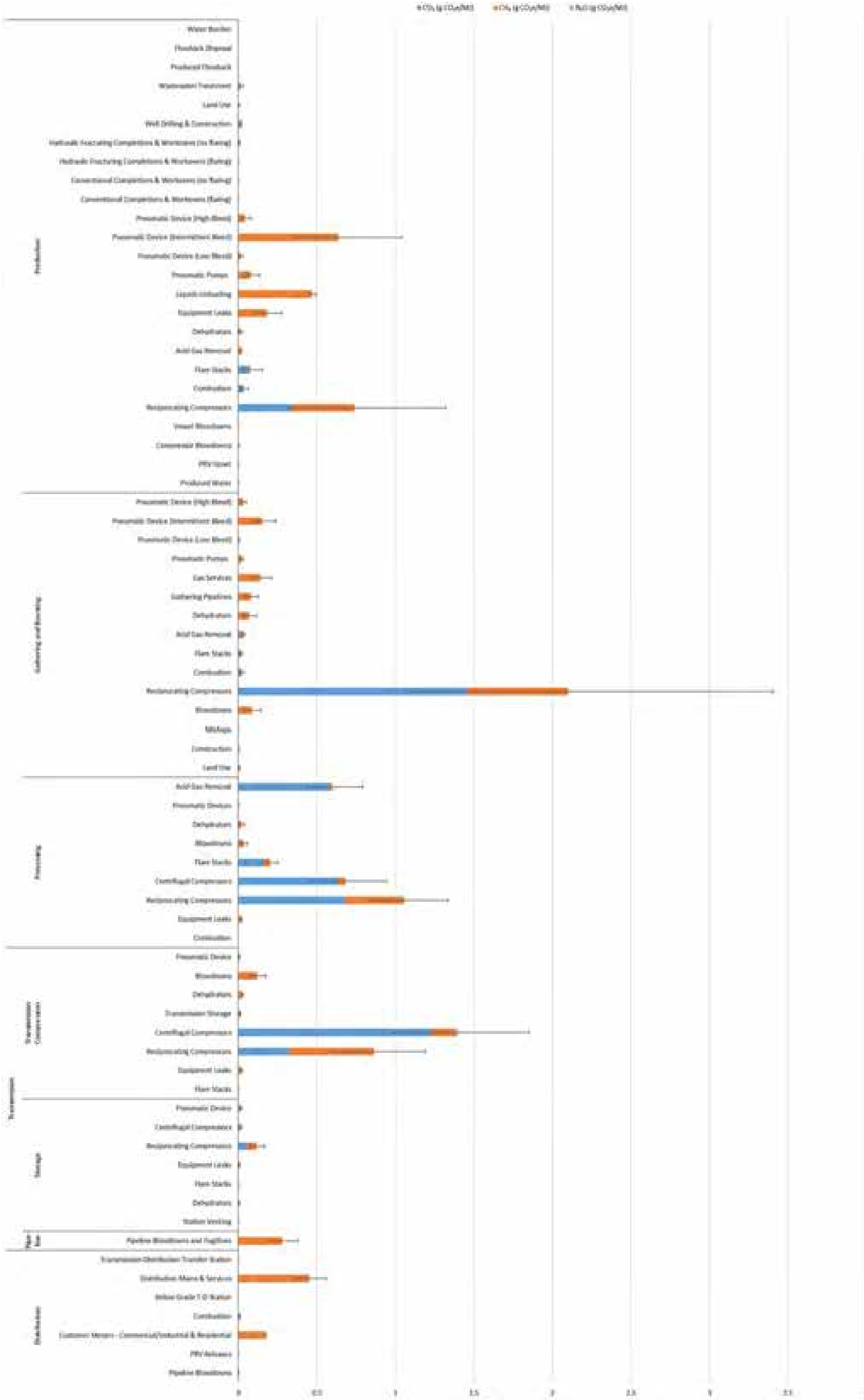
Key drivers of GHG emissions results for the entire U.S. gas supply chain in 2017 are illustrated in Exhibit 2-5 (Littlefield et al., 2020). Pneumatic devices and compression systems represent a significant portion of the total life cycle GHG emissions associated with the natural gas supply chain (NETL, 2019a).

Pneumatic devices are used to operate level controllers, valves, and other equipment at natural gas facilities. According to EPA's GHGI, pneumatics in the production segment emitted 1,060 kilotons of CH_4 in 2017, accounting for 16 percent of the total CH_4 emissions from the natural gas supply chain. Pneumatic device activity is concentrated at production facilities and there were 833,000 pneumatic devices used by U.S. production facilities in 2019 (Littlefield et al., 2020).

Natural gas is compressed for transport from processing facilities to end-consumers. As such, upstream GHG emissions are sensitive to pipeline distances and the number of compressors along these pipelines that the natural gas must pass through. The energy intensity of compression and the fugitive CH_4 emissions from compressors both contribute to upstream GHG emissions (NETL, 2019a).

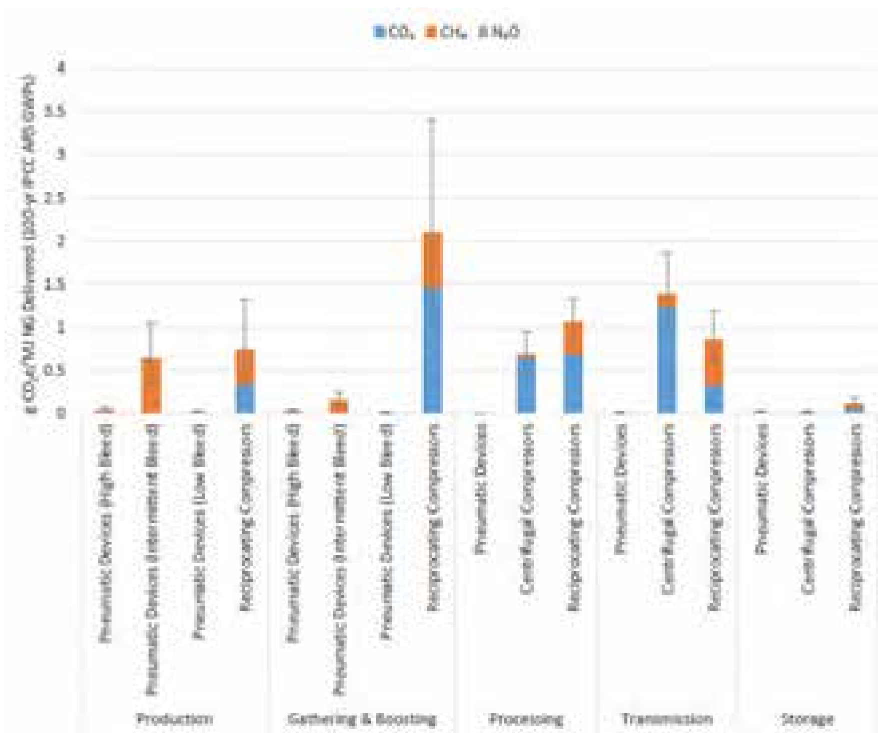
In addition to being a source of CH_4 emissions, compressors are also a source of CO_2 emissions. Most compressors in the U.S. pipeline transmission network are powered by natural gas that is withdrawn from the pipeline itself. Electric motors are not widely used by natural gas pipelines but are installed where local emissions regulations limit the use of internal combustion engines or where inexpensive electricity is available. Nationwide in 2017, 6 percent of compressor stations were powered by electricity, 77 percent were powered by natural gas, and 17 percent were dual gas and electric (Littlefield et al., 2020).

Exhibit 2-5. U.S. average for 2017—detailed GHG emissions sources for the U.S. natural gas supply chain (gCO_2e/MJ)



Two sources of CH_4 emissions from compressor systems include 1) uncombusted CH_4 that slips through the compressor exhaust stream and 2) CH_4 that escapes through compressor seals or packing. Natural gas systems use both centrifugal and reciprocating compressors. Centrifugal compressors are more appropriate for pressure boosting applications in steady-state applications (such as with a transmission pipeline), while reciprocating compressors are more appropriate when gas flow is variable and when large increases in pressure are required. Centrifugal compressors are typically driven by gas-fired turbines but, in some instances, are driven by an electric motor. Reciprocating compressors are driven by gas-fueled engines. Exhibit 2-6 illustrates the emissions associated with pneumatic devices and compressors (Littlefield et al., 2020).

Exhibit 2-6. GHG emissions from pneumatic devices and compressors across the natural gas supply chain (gCO_2e/MJ)



For all natural gas production types, the GHG emissions results produced by an LCA are sensitive to the following factors:

- Estimated ultimate recovery

- Regional natural gas composition differences (dry versus sour gas)
- Compression energy requirements and type
- Pneumatic device type, frequency, and number of devices per operation

In the same NETL (2019a) report, NETL analyzed the N_2O emissions at each stage of the natural gas supply chain. The analysis found a total of 0.14 milligrams (mg) of N_2O were emitted per MJ of natural gas delivered (Exhibit 2-7). The largest contributor (86 percent) to this total number was N_2O emissions that occur during the transmission stage.

Commented [SH10]: Since N2O is more relevant in the discussion of GHGs, I have moved this up from Chapter 3.

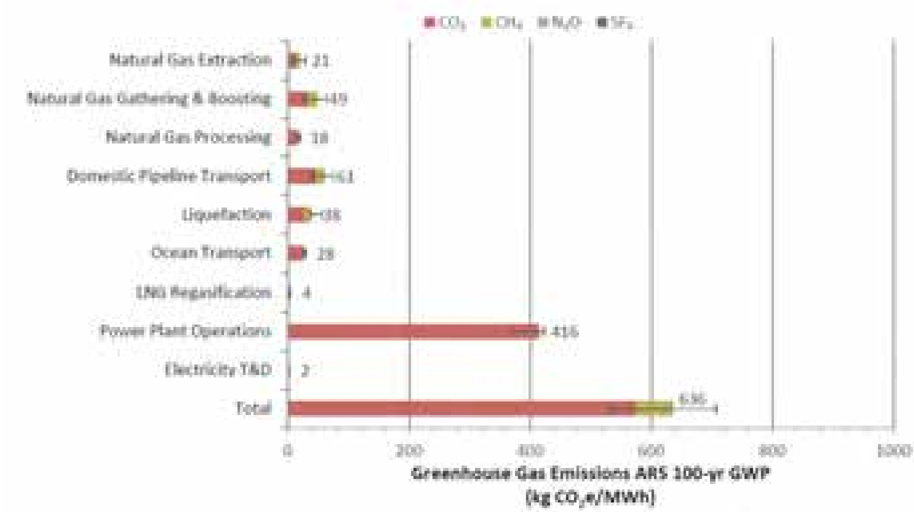
Commented [SH11R10]: Open to removal if DOE HQ team feels this is not worth a specific call-out

Exhibit 2-7. N_2O emissions across the natural gas supply chain

Stage of Natural Gas Supply Chain	N_2O Emissions (mg/MJ)
Production	0.016
G&B	< 0.0001
Processing	0.0047
Transmission	0.12
Storage	< 0.0001
Pipeline	< 0.0001
Distribution	< 0.0001
Total	*0.14*

In addition to its characterization of domestic upstream natural gas, NETL also developed life cycle data for exported LNG, including the GHG emissions from liquefaction, transport, regasification, and combustion for electricity generation (NETL, 2019b). The NETL (2019b) report that analyzed the lifecycle emissions of exporting U.S. LNG to Europe yielded the emissions results (assuming end-use in electricity generation) detailed in Exhibit 2-8.

Exhibit 2-8. GHG emissions from exporting LNG from the United States to Europe



2.3 METHANE EMISSIONS STUDIES

There are two primary approaches used to estimate CH_4 emissions as part of an LCA: 1) top-down and 2) bottom-up (Rutherford et al., 2021; Alvarez et al., 2018; Balcombe et al., 2016). A top-down approach a) measures the atmospheric concentrations of CH_4 as reported by fixed ground monitors, mobile ground monitors, aircraft, and/or satellite monitoring platforms; b) aggregates the results to estimate total CH_4 emissions; and c) allocates a portion of these total emissions to each of the different supply chain activities. A bottom-up approach measures GHG emissions directly from each source of emissions, then aggregates and extrapolates these measurements to estimate emissions for an entire region or process. Both approaches have advantages and disadvantages.

Top-down approaches (see Rutherford et al., 2021; Alvarez et al., 2018; Balcombe et al., 2016) tend to report higher emissions from natural gas systems as compared to bottom-up approaches. There are several factors that may lead to these results, which can be generally explained as follows:

- Top-down approaches capture more emissions sources by covering an entire area. However, depending on the methodology, these approaches sometimes fail to distinguish between different sectors. For example, aircraft that are used to collect emissions data for a particular area may struggle to distinguish between the CH_4 emissions coming from a natural gas processing facility in the area from those coming from a nearby dairy farm. This can lead to incorrect contributions of total CH_4 emissions to specific natural gas activities.

- Bottom-up approaches sometimes fail to capture infrequent high emitting events such as malfunctioning or improperly operated equipment. Because bottom-up approaches measure emissions from individual sources, it can be challenging to accurately capture the contributions of infrequent events to total emissions.

Considerable recent and ongoing research has been devoted to understanding and reconciling the differences between top-down and bottom-up approaches to estimating CH_4 emissions. Example studies include the following:

- The Colorado State University (CSU) Energy Institute's Basin Methane Reconciliation Study—commissioned by NETL, through the Research Partnership to Secure Energy for America (RPSEA) program—was designed to understand, and potentially reconcile, the persistent gap between top-down and bottom-up CH_4 emissions estimates for production regions (CSU, 2018; Vaughn et al., 2018). To minimize the potential shortcomings of prior studies, the Basin Methane Reconciliation Study was designed as a first of its kind to conduct contemporaneous measurements at the device, facility, and regional scales, with site access and activity and emissions data input from local natural gas operators. The study was a multi-agency research project that drew from the scientific expertise of CSU, Colorado School of Mines, University of Colorado-Boulder, the National Oceanic and Atmospheric Administration, and the National Renewable Energy Laboratory. The University of Wyoming, AECOM, Aerodyne, and GHD Engineering also participated in the study.
- In 2019, Environmental Defense Fund launched the Permian Methane Analysis Project (PermianMAP), a first-ever, near real-time CH_4 monitoring initiative in the world's largest oil field (Environmental Defense Fund, 2021; Lyon et al., 2021). Researchers first began collecting aerial CH_4 data in late fall of 2019 and conducted more than 100 flights across the Basin throughout 2020 and 2021. Some flights encompassed the full perimeter of the 10,000 square kilometers (km^2) study area. Others zeroed in on a cluster of randomly selected wells. Carbon Mapper researchers partnered with the PermianMAP project in the summer and fall of 2021, detecting nearly 1,700 plumes over 26 flight days. Leak Surveys Inc., a veteran leak detection company, used a helicopter equipped with an infrared camera to conduct surveys of more than 3,000 flares across the entire Permian Basin to determine their contribution to the region's CH_4 emissions.

Alvarez et al. (2018) note that in many bottom-up approaches to modeling, operator cooperation is required to obtain site access for accurate emissions measurements. Operators with lower-emitting sites are plausibly more likely to cooperate with such studies and workers are plausibly more likely to be careful to avoid errors or fix problems when measurement teams are on site or about to arrive, which could lead to a downward bias in estimates of potential emissions (Rutherford et al., 2021; Alvarez et al., 2018; Balcombe et al., 2016).

Balcombe et al. (2016) document the wide range of CH_4 emissions estimates across the natural gas supply chain. Significant drivers of this wide range of projections are 1) the emissions associated with natural gas production, and 2) whether the natural gas is ultimately converted to LNG. The following sub-sections explore these different segments of the supply chain.

2.3.1 Natural Gas Production Analyses

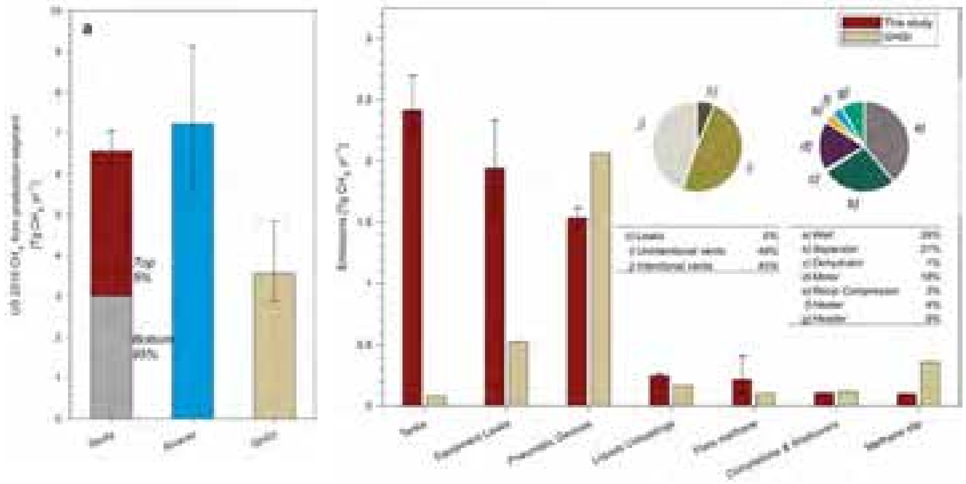
EPA estimates oil and natural gas CH_4 emissions in the annual GHGI it produces. The GHGI uses a bottom-up approach to estimate national CH_4 emissions. Several studies have found that CH_4 emissions from the natural supply chain are about 1.5–2.5 times the amount reported in EPA's GHGI (Rutherford et al., 2021; Alvarez et al., 2018; Balcombe et al., 2016). Much of the discrepancy can be attributed to differences in the analyses performed for the production segment of the natural gas supply chain where infrequent, high emissions events, or "super emitters," and emissions-intensive equipment are prevalent (Rutherford et al., 2021; Alvarez et al., 2018; Balcombe et al., 2016).

To isolate specific sources of disagreement between EPA's GHGI and other studies, Rutherford et al. (2021) reconstructed EPA's GHGI emissions factors, beginning with the underlying datasets, and identified possible sources of disagreement between inventory methods and top-down studies. The adjusted emissions factors are direct inputs in the Rutherford et al. (2021) study outputs. Rutherford et al. use a bottom-up measurement approach, yet the approach differs from the GHGI in that it applies a bootstrap resampling statistical approach to allow for inclusion of infrequent, large emitters, thereby incorporating data on super emitters in a more robust way.

Rutherford et al. (2021) estimate the mean, production-normalized emissions rate from the production segment as 1.3 percent (1.2–1.4 percent at 95 percent confidence interval, based on gross natural gas production of 32 Tcf and an average CH_4 content of 82 percent), slightly lower than Alvarez et al., 2018) who estimate it at 1.4 percent. Rutherford et al. (2021) estimate mean natural gas production-segment CH_4 emissions as equal to 6.6 teragrams (Tg) per year (6.1–7.1 Tg per year, at 95 percent confidence interval). Both the results of Rutherford et al. (2021) and Alvarez et al. (2018) are approximately two times larger than estimates of the 2015 EPA GHGI, which suggests that 3.6 Tg of emissions per year (year 2015 data, excludes offshore systems) come from the natural gas production segment.

Given that the Rutherford et al. (2021) results match Alvarez et al.'s (2018) site-level results, the former concludes that the divergence between the GHGI and top-down/site-level studies is not likely to be due to any inherent issue with the bottoms-up approach. A results comparison of the Rutherford et al. (2021) study, the Alvarez et al. (2018) study, and 2015 EPA GHGI data can be found in Exhibit 2-9.

Exhibit 2-9. Comparison of GHG emissions results from Rutherford et al., Alvarez, et al., and EPA GHGI



Note: "This study" and "Study" labels on the x-axis refer to Rutherford et al. (2021)

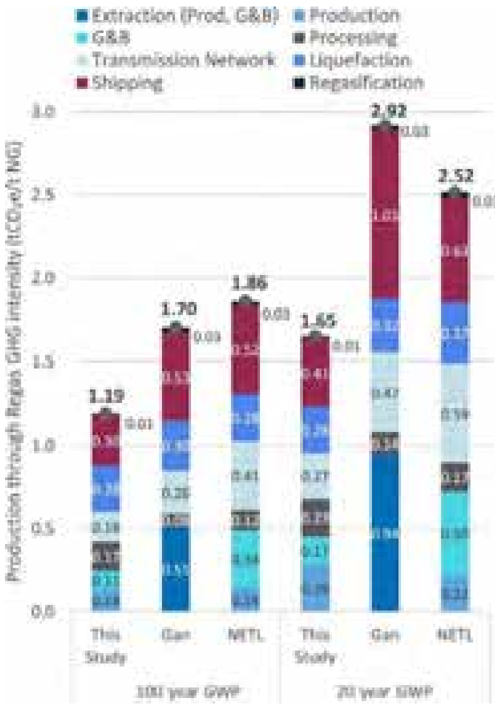
Used with permission from Rutherford et al. (2021)

Littlefield, Rai, and Skone (2022) provide a detailed life cycle perspective on GHG emissions variability where natural gas is produced and where it is delivered (via pipeline). They disaggregate transmission and distribution infrastructure into six regions, balance natural gas supply and demand locations to infer the likely pathways between production and delivery (estimated via modeling as actual tracking of natural gas from well to customer is not technically feasible), and incorporate new data on distribution meters. They find the average transmission distance for U.S. natural gas is 815 kilometers (km) but ranges 45–3,000 km across estimated production-to-delivery pairings examined (Littlefield, Rai, and Skone, 2022). In terms of total GHG emissions, their results suggest the delivery of 1 MJ of natural gas to the Pacific region has the highest mean life cycle GHG emissions (13.0 gCO_2e/MJ) and the delivery of natural gas to the Northeastern region of the United States has the lowest mean life cycle GHG emissions (8.1 gCO_2e/MJ).

2.3.2 LNG Studies

At the end of 2020, Cheniere Energy was the largest exporter of LNG from the United States in terms of volume. Roman-White et al. (2021) developed an LCA framework to estimate GHG emissions representative of Cheniere's LNG supply chain, considering both upstream and downstream sources of emissions from Cheniere's Sabine Pass Liquefaction facility, using supplier-specific data collected from wellhead through ocean transport. Roman-White et al. (2021) compare the GHG emissions intensity of Cheniere LNG to two similar assessments of emissions intensity from U.S. LNG transported to China (Gan et al., 2020; NETL, 2019b). The results of their comparison are illustrated in Exhibit 2-10.

Exhibit 2-10. Comparison of GHG emissions results from Roman-White et al., Gan et al., and NETL



Used with permission from Roman-White et al. (2021)

Note: "This study" labels on the x-axis refer to Roman-White et al. (2021)

The NETL (2019b) LNG study uses more recent production emissions data (2016 data) than Gan et al. (2020). The NETL (2019b) study is based on natural gas production in Appalachia with relatively low emissions intensity. The NETL analysis differs from the Roman-White et al. (2021) study primarily in the intensity of the G&B and transmission stages, which are driven by differences in individual facility performance.

When modeling transmission compression, the NETL (2019b) study assumes a factor of 0.97 horsepower-hour (HPh)/thousand cubic feet (Mcf) to estimate the transmission station throughput (derived from NETL-published parameters). The average ratio of HPh to Mcf of throughput, from Cheniere Energy's known suppliers (used in the Roman-White et al. study) is 0.27 HPh/Mcf, which is based on supplier data collection completed. For modeling gas from other transmission operators, the GHGRP does not publicly provide the throughput of compressor stations. The Roman-White et al. (2021) study assumes 0.29 HPh/Mcf based on data reported by EIA.

The higher factor used by the NETL (2019b) study results in increased modeled fuel consumption across the transmission network. The Roman-White et al. liquefaction GHG intensity is 8–13 percent less than the intensity estimated by Gan et al. and is comparable to the NETL (2019) study estimate on a 100-year basis. The Roman-White et al. (2021) study concludes ocean transport stage emissions intensity is 42–60 percent less than the transport emissions intensity of Gan et al. (2020), and 35–42 percent less than that of the NETL (2019b) study. A separate study from Abrahams et al. (2015) notes that emissions from the shipping of LNG exports from the United States to ports in Asian and European markets account for only 3.5–5.5 percent of precombustion life cycle emissions; hence, Abrahams et al. (2015) concludes that shipping distance is not a major driver of GHGs in the LNG supply chain.

Jordaan et al. (2022) estimate global average life cycle GHG emissions from the delivery of gas-fired electricity to be 645 gCO_2e per kilowatt hour (kWh) (334–1,389 gCO_2e per kWh), amounting to 3.6 gigatonne CO_2e per year in 2017 (10 percent of energy-related emissions). This result is comparable to the results obtained by Roman-White et al. (2021), who report life cycle GHG emissions of 524 gCO_2e kWh for electricity produced in China using LNG supplied by U.S. LNG exporter Cheniere Energy, and 636 gCO_2e per kWh reported by NETL (2019b). Exhibit 2-11 summarizes these results.

Exhibit 2-11. LCA results comparison of LNG-derived electricity

LNG LCA Study	Mean gCO_2e per kWh
NETL (2019b)	636
Roman-White et al. (2021)	524
Jordaan et al. (2022)	645

Across these studies, the primary difference in the GHG results comes from assumptions about emissions associated with natural gas extraction and G&B portions of the natural gas supply chain.

2.4 Methane Emissions Research and Development

DOE's Methane Mitigation Technologies program aims to eliminate non-trivial CH_4 emissions from the oil and gas supply chain by 2030. These non-trivial CH_4 emissions include CH_4 production, processing, transportation, and use.

The Methane Mitigation Technologies program is focused on developing accurate, cost-effective, and efficient technology solutions and best practices to identify, measure, monitor and eliminate CH_4 emissions from these sources. Methane mitigation R&D efforts include advanced materials of pipeline construction, monitoring sensors, data management systems, and more efficient and flexible compressor stations. Research efforts for CH_4 emissions quantification focus on developing technologies to detect, locate, and measure emissions. This includes the development and validation of measurement sensor technologies for the collection, dissemination, and analysis of emissions data, which will inform efforts, such as the GHGI and orphan well remediation programs of EPA and DOI, respectively. The following three areas comprise DOE's current research, development, and demonstration (RD&D) efforts to identify, address, and reduce oil and natural gas sector emissions.

- Methane Emissions Quantification — activities focus on direct and remote measurement sensor technologies, data acquisition, research, and advanced analytics that quantify CH_4 emissions from point sources along the upstream and midstream portion of the natural gas value chain.
- Methane Emissions Mitigation — project investments and activities aim to develop advanced materials, data management tools, inspection and repair technologies, and advanced compressor technologies for eliminating fugitive CH_4 emissions across the natural gas value chain.
- Undocumented Orphaned Wells — cooperative RD&D efforts involving the Interstate Oil and Gas Compact Commission (IOGCC) are designed and implemented to assist the Federal land management agencies, States, and Indian Tribes in identifying and characterizing undocumented orphaned wells, primarily by developing and testing innovative technologies and approaches that locate and characterize orphaned wells to enable well plugging efforts being administered under DOI's Orphaned Well Plugging Program.

There are several mitigation measures available to address the GHG emissions from the natural gas supply chain, including equipment upgrades and process optimization.[p] Additionally, advancing technologies to detect and measure fugitive and vented CH_4 emissions can help to identify leaks and super emitters.

2.4.1 Detection and Measurement

Alvarez et al. (2018) note that key aspects of effective mitigation include pairing well-established technologies and best practices for routine emissions sources with economically viable systems to rapidly detect the root causes of high emissions arising from abnormal conditions. The latter could involve combinations of current technologies, such as on-site leak surveys by company personnel using optical gas imaging, deployment of passive sensors at individual facilities or mounted on ground-based work trucks, and in situ remote-sensing approaches using tower networks, aircraft, or satellites. Over time, the development of less failure-prone systems would be expected through repeated observation of, and further research into, common causes of abnormal emissions, followed by reengineered design of individual components and processes.

Roman-White et al. (2021) note that for LNG, harmonized data collection and reporting would build confidence in supplier claims about LCA emissions, enabling comparisons between natural gas supply chains and supporting climate goals for all participants in the supply chain. This could stimulate a virtuous cycle of demand for GHG accounting and reduction and provision of more granular, company-specific emissions estimates.

According to Stern (2022), three major requirements for creating credible measuring, reporting, and verification of CH_4 emissions are 1) to move measurement and reporting of CH_4 emissions from standard factors—either engineering-based or from EPA data—to empirical (Tier 3)

[p] Examples of equipment upgrades in this context include compressor seals, reciprocating compressors, and pneumatic controls.

measurements, and to reconcile bottoms-up (ground level) and top-down (satellite/aircraft/drone) observations; 2) to ensure that data measurement and reporting has been verified and certified by accredited bodies; and 3) to require asset-level emissions data to be transparent and publicly available. Failure to do so on grounds of commercial confidentiality risks being interpreted as evidence that the data is not credible.

2.4.2 Equipment Upgrades and Process Optimization

Compressor seals include wet seals used by centrifugal compressors and rod packing used by reciprocating compressors. Wet seals surround the rotating shaft of a centrifugal compressor with oil, which prevents gas leakage from the compressors. The oil used by wet seals must be continuously regenerated, which releases CH_4 into the atmosphere. By replacing wet seals with mechanical dry seals, the CH_4 emissions from centrifugal compressors can be reduced.

Reciprocating compressors prevent CH_4 leakage by encasing each compressor rod with a set of oil-coated, flexible rings. Proper maintenance and routine replacement of these rings prevents unnecessary leakage of CH_4. Storage tanks hold flowback water and liquid hydrocarbons recovered from the production stream. Variable loading levels and temperatures cause the venting of CH_4 and other gases from these tanks. By installing vapor recovery units on storage tanks, producers can more effectively reduce emissions from natural gas production. The captured emissions can be combusted on site to provide process energy, or they can be channeled to the sales stream.

Pneumatic controllers use gas pressure to open and close valves throughout a natural gas production and processing system. Natural gas is commonly used to pressurize pneumatic control systems. The bleeding of natural gas from pneumatic controllers leads to venting CH_4 to the atmosphere. The GHG impact of pneumatic control systems can be reduced by installing pneumatic systems that use pressurized air instead of pressurized natural gas.

Regulations mandate emissions reductions from pneumatically controlled valves and compressor seals. The data suggest that the use of this equipment reduces completion emissions by approximately 75−99 percent.

The practice of reduced emissions completions (RECs) utilizes equipment that allows the capture of gas during flowback, either to be sent to the product line or, if this is not feasible, to be flared. In the United States, the use of RECs is compulsory by law. REC implementation has shifted the emissions from CH_4 to CO_2; there is evidence it has reduced the GHG intensity of completions (Balcombe et al., 2016; Balcombe, Brandon, and Hawkes, 2018).

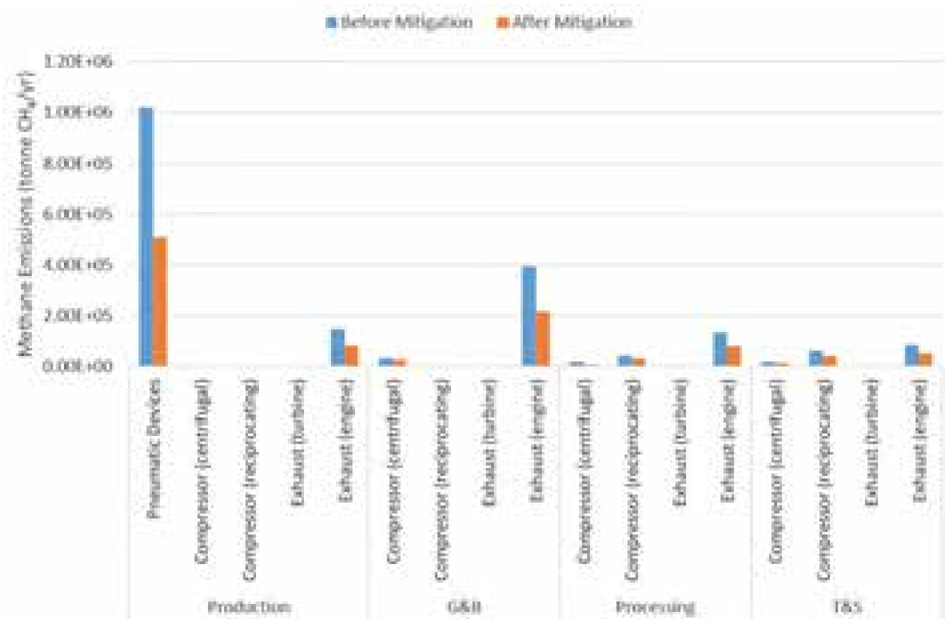
A 2020 report produced by NETL—Littlefield et al. (2020)—notes that compressed-air pneumatics are a mature technology that can reduce CH_4 emissions from pneumatic systems. The technology replaces existing devices, which are actuated by natural gas, with devices that are actuated with compressed air. This requires the addition of electric-powered air compressors at natural gas facilities but can result in zero CH_4 emissions from pneumatics. The same report notes that proven technologies exist for reducing CH_4 emissions from compression systems (as described below):

- Centrifugal compressors emissions can be reduced by replacing wet seals with dry seals. These seals are used around the rotating shaft of the compressor and prevent high pressure gas from escaping the compressor. Wet seals involve the use of recirculating oil that emits 40–200 standard cubic feet (scf) of natural gas per minute (min). Dry seals use gas to seal the compressor shaft and emit only 6 scf/min. The replacement of wet seals with dry seals reduces centrifugal compressor emissions by 85–97 percent.
- Reciprocating compressor emissions can be reduced by replacement of rod packing. Packing prevents gas from moving around piston rods and escaping the compression cylinder. New packing that is properly installed on a well-maintained compressor will emit about 12 scf/hour. The emissions rate for old or poorly installed packing can range 25–67 scf/hour. When compared to the emissions rate for new packing, this equates to potential emissions reductions of 52–82 percent. Rod packing replacement is a mature technology, but there are new technologies that can also reduce reciprocating engine exhaust slip. These new technologies include advanced materials that increase piston rod service life while reducing rod wear and Teflon-coated rings that reduce friction while maintaining a tight seal. There are no data currently available, however, on the emissions reduction potential tied to deploying these new technologies.
- The majority of the CH_4 emissions from reciprocating compressors are due to the CH_4 slip from engine exhaust. Comparing the exhaust emissions factors for rich burn and lean burn engines,[q] respectively, shows that rich burn engines have a combustion effectiveness of 97 percent and lean burn engines have combustion effectiveness of 99 percent. Air-fuel-ratio controls are an option for improving the combustion effectiveness of lean burn engines while keeping NOx emissions low. More research is required to understand the limits of air-fuel-ratio controls but, for this analysis, it is assumed that they can increase the combustion effectiveness of a lean burn engine by 97–99 percent.

Exhibit 2-12 illustrates the potential impact of these mitigation approaches (Littlefield et. al 2020).

[q] The terms rich-burn and lean-burn simply refer to the way in which the engine burns fuel—the air-to-fuel ratio. A rich-burn engine is characterized by excess fuel in the combustion chamber during combustion; a lean-burn engine is characterized by excess air in the combustion chamber during combustion.

Exhibit 2-12. Illustration of mitigation measure impact for pneumatic devices and compressors



Balcombe, Brandon, and Hawkes (2018) note that pre-emptive maintenance and a faster response to detection of high emissions are methods for reducing the impact of super emitters. Identifying a cost-effective solution is imperative, and much attention is being given to developing lower cost emissions monitoring and detection equipment. As Brandt, Heath, and Cooley (2016) point out, identifying larger leaks from the highest emitters may be carried out using less sensitive, and consequently cheaper, detectors in areas representing the highest risk.

2.4.3 Liquefaction Emissions Mitigation Measures

With respect to liquefaction, Mokhatab (2014) note that most of the plant energy consumption and resultant emissions in natural gas liquefaction facilities occur in the compressor drivers, where fuel energy (usually natural gas) is converted to mechanical work (or electricity in case of electrically driven compressors). Due to the energy consumption scale of the LNG plants, any enhancement to the energy efficiency of a plant will result in a significant reduction in gas consumption and consequently CO_2 emissions (Mokhatab, 2014).

There are two ways to increase the energy efficiency of LNG plants: 1) liquefaction cycle enhancement and 2) driver cycle enhancement. Liquefaction cycle enhancements reduce compressor power and consequently the compressor driver's fuel consumption. Driver cycle enhancement reduces the amount of fuel consumption to generate a specific amount of power.

Typical fuel sources for natural gas liquefaction cycles include either pure refrigerant in cascade cycles, expansion-based cycles, or mixed refrigerant cycles.

Pure refrigerant cycles have a constant evaporating temperature that is a function of the saturation pressure. Mixed refrigerant cycles do not maintain a constant evaporating temperature at a given pressure. Their evaporating temperature can range and change depending on the pressure and composition. A refrigerant mixture of hydrocarbons and nitrogen is chosen so that it has an evaporation curve that matches the cooling curve of the natural gas with the minimum temperature difference. Therefore, small temperature differences reduce entropy generation and, thus, improve thermodynamic efficiency, reduce power consumption, and reduce the emissions associated with liquefaction facilities (Mokhatab 2014).

A study from Pospíšil et al. (2019) notes that a certain part of the energy spent on liquefaction can be recovered by the utilization of the cold stream from LNG. The amount of usable cold is given by thermophysical properties of natural gas and corresponds to 830 kilojoule (kJ)/kg of LNG. This cold energy can be recovered during the regasification process.[r] Regasification is carried out either in port terminals before natural gas is transported via gas lines or directly before the use of natural gas. The exploitation of cold from LNG is quite limited at present. Most of the available cold is wasted during the regasification process when LNG is heated up by water or ambient air. Inefficient use of cold temperature streams reduces the overall efficiency of this primary energy source and leads to greater emissions. Pospíšil et al. (2019) recommends that promising ways of utilizing cold from LNG in the regasification process should be explored and implemented (Pospíšil et al., 2019).

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[r] LNG is kept in liquid form through maintaining a storage and transport temperature of approximately -160 °C. When LNG is regasified, there are hot and cold "streams" in the process. Through heat-integration (using heat exchangers, for example), one can utilize a hot or cold stream of a thermochemical process to supply or remove heat from another part of the process.

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3 AIR QUALITY

There are two primary air emissions pathways from sources in the natural gas supply chain 1) the leaking, venting, transport, and combustion of natural gas; and 2) the combustion of natural gas and other fossil fuel resources or other emissions during associated operations (e.g., extraction, transportation, downstream combustion). Emissions sources include pad, road, and pipeline construction; well drilling, completion, and flowback activities; and natural gas processing and transmission equipment such as controllers, compressors, dehydrators, pipes, and storage vessels. Pollutants include, most prominently, CH_4 and volatile organic compounds (VOCs)—of which the natural gas industry is one of the highest-emitting industrial sectors in the United States—in addition to NOx, sulfur dioxide (SO_2), and various forms of other hazardous air pollutants (HAPs) (Congressional Research Service [CRS], 2020). Pollutants are described in detail below (CRS, 2020):

- CH_4 is the principal component of natural gas and is a precursor to ground-level ozone formation (i.e., "smog").
- NOx is a ground-level ozone precursor.[s] Significant amounts of NOx are emitted during the combustion of natural gas and other fossil fuels (e.g., diesel). The combustion of natural gas occurs when it is flared during drilling and well completions and when used to drive the various compressors that move products through the system. Combustion also occurs in engines, drills, heaters, boilers, and other production equipment.
- VOCs are a ground-level ozone precursor. The crude oil and natural gas sector is currently one of the largest sources of VOC emissions in the United States, accounting for approximately 20 percent of man-made VOC emissions nationwide (and representing almost 40 percent of VOC emissions released by stationary sources).[t] VOCs—in the form of various hydrocarbons—are emitted throughout a wide range of natural gas operations and equipment. The interaction among VOCs, NOx, and sunlight in the atmosphere contributes to the formation of ozone.
- SO_2 is emitted from crude oil and natural gas production and processing operations that handle and treat sulfur-rich, or "sour," gas.
- HAPs[u], also known as air toxins, are those pollutants that are known or suspected to cause cancer or contribute to other serious health effects including reproductive issues and birth defects. The most common HAPs produced from natural gas systems are n-hexane and benzene, toluene, ethylbenzene, and xylenes (BTEX) compounds. Some natural gas reservoirs may also contain high levels of hydrogen sulfide (H_2S). HAPs are

[s] NOx is the collective term for the nitrogen oxides nitrogen monoxide and nitrogen dioxide.

[t] EPA's 2014 National Emissions Inventory estimated VOC emissions from "oil and gas" stationary sources to be 3.23 MM tons, from all stationary sources to be 8.26 MM tons, and from all anthropogenic sources to be 16.48 MM tons. Data for VOCs, as well as the other criteria pollutants and HAPs, are derived from EPA's National Emissions Inventory, available at https://www.epa.gov/sites/production/files/2017-04/documents/2014neiv1_profile_final_april182017.pdf.

[U] The EPA has a list of over 180 chemicals that they have determined are toxic air pollutants, or HAPs. Some VOCs are included on that list, so the two concepts (HAPs and VOCs) are not mutually exclusive.

found primarily in natural gas itself and are emitted from equipment leaks and during processing, compressing, transmission, distribution, or storage operations. HAPs are also a byproduct of incomplete fuel combustion and may be components in various chemical additives.

3.1 Upstream Production and Hydraulic Fracturing

The venting of natural gas during extraction and processing is a key source of VOC emissions. Similar to CH_4, VOCs are a naturally occurring constituent of natural gas and can react with other pollutants to produce ground-level ozone. Another source of VOC emissions during upstream operations is venting from condensate storage tanks, which occurs in regions with wet gas.[v]

The combustion of natural gas in compressors and gas processing equipment produces NOx and carbon monoxide (CO). Similarly, the combustion of diesel in drilling equipment produces NOx and CO, as well as significant quantities of SO_2 emissions. Beyond VOCs, CH_4, NOx, CO, and SO_2 emissions, upstream processes can also produce aliphatic hydrocarbons, (e.g., C2–C5), alkanes, VOCs (e.g., BTEX), H_2S, n-hexane, and formaldehyde, which can contaminate ambient air (Wollin et al., 2020).

Elliott et al. (2017) estimates that up to 143 air contaminants can be released during hydraulic fracturing. The International Agency for Research on Cancer generates hazard assessments for only 20 percent of these identified contaminants. Twenty of these air contaminants are known carcinogens. Other air contaminants are generated by the peripheral plant components. These include particulate matter, NOx, precursors of ozone and polycyclic aromatic hydrocarbons (Wollin et al., 2020).

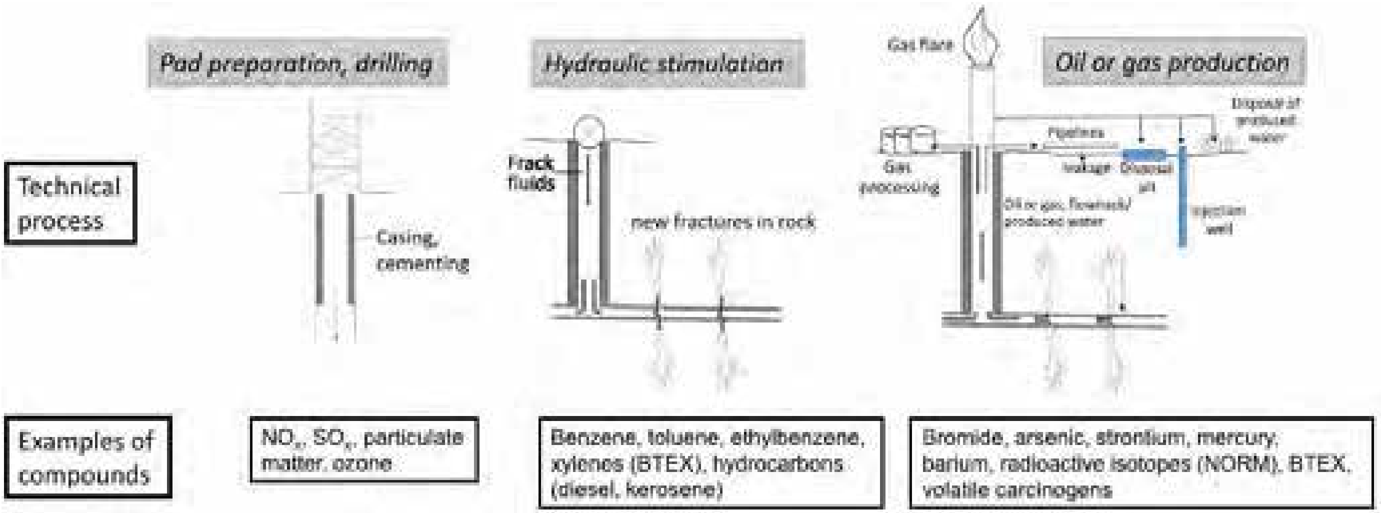
The following activities are known to contribute to air contamination at oil or gas drilling sites:

- Preparation of the drilling site including road connections
- Drilling of the well
- Truck traffic for delivery and disposal of materials
- Removal of acid gases and water from gas; separation of natural gas from other hydrocarbons
- Operation of compressor stations to enable the transport of natural gas into transport pipelines
- Preprocessing of crude oil prior to refinery

Exhibit 3-1 illustrates the supply chain for natural gas where each of these activities occurs (Wollin, 2020).

[v] When natural gas is retrieved, it can be considered wet or dry. Dry natural gas is at least 85 percent CH_4, but often more. Wet natural gas contains some CH_4, but also contains liquids such as ethane, propane, or butane. The more CH_4 natural gas contains, the "dryer" it is considered.

Exhibit 3-1. Illustration of supply chain steps where upstream air pollution occurs



Used with permission from Wollin et al. (2020)

NOx and SOx emissions have been reported to be higher during the development of the drilling site compared to during the production phase (Wollin et al., 2020). Similar observations have been made for particulate matter (PM) (e.g., PM2.5 and PM10). Analysis of shale gas production sites in North Texas showed an 8 percent increase in ozone concentrations at natural gas production sites compared to control sites (Wollin et al., 2020).

Indirect energy consumption can also affect the air quality profile of gas extraction technologies. If the development or operation of a natural gas well uses grid electricity, then the fuel mix of the electricity grid will affect the life cycle performance of the well. The indirect air quality impacts of electricity consumption depend on the fuel mixes and combustion characteristics of power plants that collectively compose a regional electricity grid. Exhibit 3-2 offers a perspective on sources of non-GHG air pollutants by supply chain step or equipment.

Exhibit 3-2. Perspective of non-GHG air pollutant by supply chain step or equipment

Source	Air pollutant				Data quality
	NO_X	VOC	PM	Other toxic substances	
Well development					
Drilling rigs	•	◦	•	•	Medium
Frac pumps	•	◦	•	•	Medium
Truck traffic	•	◦	•	•	Medium
Completion venting		•		•	Poor
Frac ponds		◦			Poor
Gas production					
Compressor stations	•	•	◦	•	Medium
Wellhead compressors	◦	◦	◦	◦	Medium
Heaters, dehydrators		◦	◦	◦	Medium
Blowdown venting		◦		◦	Poor
Condensate tanks		•		◦	Poor
Fugitives				◦	Poor
Pneumatics		◦		◦	Poor

• Major source, ◦ minor source

Used with permission from Wollin et al. (2020)

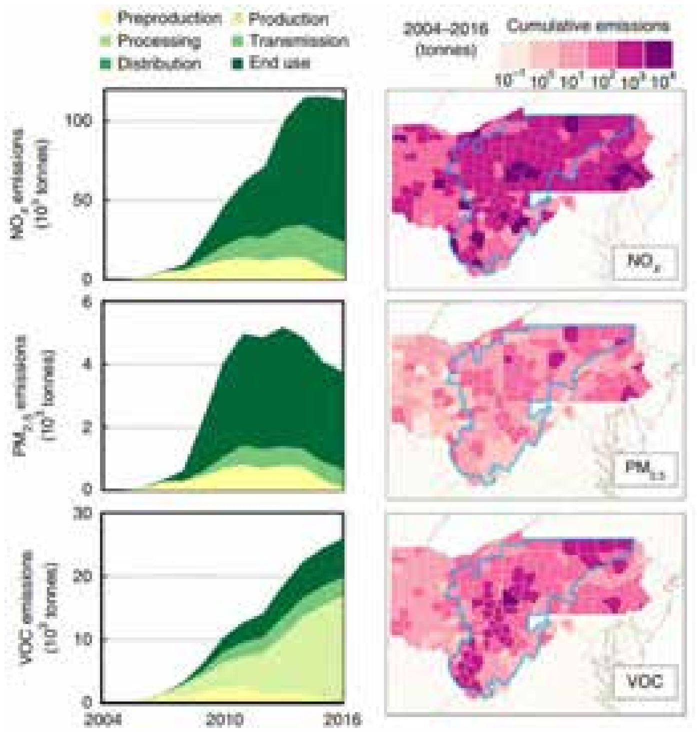
McMullin et al. (2018) analyzed exposure to VOCs emitted during hydraulic fracturing in Colorado. They identified 56 different VOCs that were emitted during hydraulic fracturing using data compiled from 47 existing air monitoring devices that measured these VOCs at 34 different locations across the region.

Plant et al. (2022) used airborne sampling to measure flare efficiency[w] in three major gas production regions in the United States. They found that both unlit flares and inefficient combustion contribute comparatively to ineffective CH_4 destruction, with flares effectively destroying only 91.1 percent (90.2–91.8 percent; 95 percent confidence interval) of CH_4 emissions. Other emissions from flaring can include carbon particles (soot), unburned hydrocarbons, CO, partially burned and altered hydrocarbons, NOx, and (if sulfur containing material such as H_2S or mercaptans is flared) SO_2. The combustion products of flaring at natural gas production and processing sites specifically include CO_2, CH_4, and N_2O.

Mayfield et al. (2019) performed an analysis of the environment impacts associated with the shale gas boom in the Appalachian Basin and found the majority (61 percent) of VOC emissions from the natural gas supply chain can be largely attributed to upstream processes and are spatially concentrated in counties with the highest cumulative production. Upstream processes contribute the most to total NOx (67 percent) and PM2.5 (73 percent) emissions across the natural gas supply chain; NOx and PM2.5 emissions are relatively evenly distributed across counties (Mayfield et al., 2019). Exhibit 3-3 presents annual NOx, PM2.5, and VOC emissions from the natural gas supply chain within Pennsylvania, Ohio, and West Virginia, along with the spatial distribution of cumulative NOx, PM2.5, and VOC emissions by county between 2004 and 2016. It is important to note that the blue lines delineate shale gas-producing counties (Mayfield et al., 2019).

[w] The flare efficiency is a measure of the effectiveness of the combustion process to fully oxidize the fuel. When inefficiencies occur, unburned fuel, CO, and other products of incomplete combustion (e.g., soot, VOCs, etc.) are emitted into the atmosphere.

Exhibit 3-3. Annual (left graphs) and cumulative (right graphs) (2004–2016) NOx, PM2.5, and VOC emissions from natural gas supply chain within Pennsylvania, Ohio, and West Virginia



Permission pending from Mayfield et al. (2019)

3.2 MIDSTREAM TRANSPORT EMISSIONS

CH_4 leakage in the transmission and distribution systems is documented in Chapter 2 – Greenhouse Gas Emissions. This mid-stream segment leakage has important air pollutant considerations, since CH_4 can be a precursor to ground-level ozone formation.

While the presence of HAPs in unprocessed, upstream natural gas has been documented, little has been published on their presence in the midstream segments of the natural gas supply chain. Nordgaard et al. (2022) systematically evaluated publicly available, industry-disclosed HAP composition data from natural gas infrastructure applications submitted to FERC between 2017 and 2020. These applications covered 45 percent of the U.S. onshore natural gas transmission system (as measured by pipeline miles). Given that reporting HAP composition data is not required by FERC, only 49 percent of approved projects disclosed their HAP composition data to FERC. Of the applications that did disclose their HAP composition data, HAP concentrations were typically reported as higher for separator flash gas and condensate tank vapor, compared to LNG and transmission-grade natural gas, with mean benzene concentrations of 1,106, 7050, 77, and 37 parts per million (ppm), respectively.

Nordgaard et al. (2022) also identified one pipeline operator that reports real-time HAP concentrations for natural gas at five pipeline interconnection points. Similar to the FERC applications, this operator reported BTEX and H_2S as present in the pipelines used to transport their natural gas. Because current transmission infrastructure releases natural gas during uncontrolled leaks, loss of containment events, and routine operations (e.g., blowouts and compressor station blowdowns), having access to HAP composition data may be important for conducting both air quality and health-focused evaluations of natural gas releases.

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4 Water Use and Quality

The literature describes the treatment and management of wastewaters as a central environmental concern regarding natural gas production. Especially in the eastern regions of the United States where—although water resources are abundant—significant natural gas production has been occurring and is expanding. In the western parts of the United States, persistent dry climates limit the use and availability of freshwater for natural gas production—specifically, freshwater availability for drilling and hydraulic fracturing.

Gallegos et al. (2015) estimate that drilling and hydraulically fracturing a shale gas well can consume 2.6–9.7 MM gallons (gal) of water. From 2014 to 2015, unconventional shale gas in the United States used 187 billion (B) gal of water. From 2012 to 2014, the average use of water for hydraulic fracturing was 30.6 B gal annually. Additionally, Gallegos et al.'s (2015) integrated data from 6–10 years of operations suggests 212 B gal of produced water[x] are generated from unconventional shale gas and oil formations.

While extensive growth in hydraulic fracturing has increased water use for natural gas production across the United States, the water use and produced water intensity of these well-stimulation activities is lower than the water use and produced water intensity of other energy extraction methods and represents only a small fraction of total industrial water use nationwide (Kondash and Vengosh, 2015). However, given the amount of water required for natural gas production, local or seasonal water supply shortages can cause issues.

Water quality can also be impacted by natural gas production processes if water is inadequately managed or by the use of fracturing chemicals both on the surface (e.g., if chemicals are inadvertently spilled and not contained)—before injection and after flowback—and in produced water. Subsurface water quality impacts can result from the migration of fracturing fluids, formation waters, and CH_4 along well bores and through rock fracture networks. Management and disposal efforts increasingly include efforts to minimize water use through recycling and re-use of fracturing fluids, in addition to treatment and disposal of wastewater through deep underground injection.

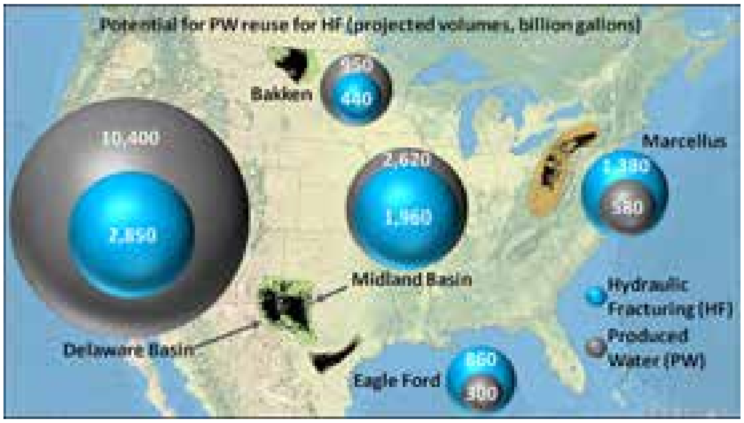
Scanlon et al. (2020a) analyze the water-related sustainability of energy extraction. They focus on meeting the rising water demand for hydraulic fracturing and managing growing volumes of water co-produced with oil and gas. They also analyze historical (2009–2017) volumes of water in ~73,000 wells and project future volumes of water use in major U.S. unconventional oil and gas plays. Their results show a marked increase in water use for fracking, depleting groundwater resources in some semi-arid regions (Scanlon et al., 2020a).

Water issues related to both fracking water demand and produced water supplies may be partially mitigated through the reuse of produced water to frack new wells. As shown in Exhibit 4-1, projected produced water volumes exceed fracking water demand in semi-arid Bakken (2.1×), Permian Midland (1.3×), and Delaware (3.7×) oil plays, with the Delaware oil play

[x] Produced water is defined as the water that is withdrawn through oil and gas extraction. Produced water can begin as ground water within the hydrocarbon bearing formations; however, as the extraction matures, or in the case of shale or tight formations where hydraulic fracturing is necessary to liberate the hydrocarbons, produced water can also contain fluids that were previously injected.

accounting for ~50 percent of the projected U.S. oil production (Scanlon et al., 2020a). Therefore, water issues could impact future energy production, particularly in semi-arid oil plays.

Exhibit 4-1. Map showing ratio between produced water and fracking water demand for major shale basins



Used with permission from Scanlon et al. (2020a)

4.1 Water Use for Unconventional Natural Gas Production

The process of hydraulic fracturing uses large volumes of water mixed with chemicals and proppant (sand) to fracture low-permeability shale and tight oil rocks, allowing the extraction of hydrocarbons. Despite the higher water intensity (the amount of water used to produce a unit of energy; for example, liters per gigajoule) compared to drilling conventional vertical oil and gas wells, overall water withdrawals for hydraulic fracturing is negligible compared to other industrial water uses on a national level (Vengosh et al., 2014; Jackson et al., 2014; Kondash, Albright, and Vengosh, 2017; Kondash and Vengosh, 2015). On a local level, however, water use for hydraulic fracturing can cause conflicts over water availability, especially in arid regions such as the western and southwestern United States where water supplies are already limited (Scanlon, Reedy, and Nicot, 2014; Ikonnikova et al. 2017; Nicot and Scanlon, 2012; Kondash, Lauer, and Vengosh, 2018).

Most of the water used for unconventional natural gas production is used as part of the hydraulic fracturing process. For example, of the total water used by the shale gas industry, hydraulic fracturing is estimated to account for about 89 percent, drilling about 10 percent, and infrastructure 1 percent (Hayes and Severin, 2012). Water is the main component of the fluids used for hydraulic fracturing, making up approximately 99 percent of the total volume.

Reporting from Gallegos, et al. (2015) suggests hydraulic fracturing uses 2.6–9.7 MM gal of water per well drilled, while the American Petroleum Institute (API) (API, 2023) suggests the average hydraulically fractured well uses 4 MM gal of water. It is important to consider the potential environmental impacts of using water from different sources (e.g., ground water, surface water). If available surface water is used to support natural gas production, then the ecosystems that rely on this water could be impacted. Significant groundwater withdrawals can permanently deplete aquifers.

4.1.1 Water Use Impacts

Water use for hydraulic fracturing and wastewater production in major shale gas and oil producing regions increased between 2011 and 2016, with water use per well increasing by up to 770 percent—and with flowback and produced water volumes generated within the first year of production increasing up to 550 percent. Water-use intensity (that is, normalized to energy production) increased in all U.S. shale basins, except the Marcellus shale basin, over this period (Kondash, Lauer, and Vengosh, 2018).

Water consumption per shale gas well can vary due to four primary factors:

- Geology: maturity of the shale and formation depth, thickness, and lateral extent
- Technology: horizontal or vertical drilling, water recycling
- Operations: operator decisions, availability of nearby freshwater
- Regulatory: requirements for use and treatment of water

During 2009−2017, ∼73,000 wells, or an aggregated total lateral length of ∼440 × 10^6 ft (134,000 km) equivalent to ∼3× the Earth's circumference (40,000 km), was drilled in eight plays studied by (Dieter et al., 2018). Dieter et al. (2018) found that to fracture the rock along that length, ∼480 B gal of water are required, equivalent to ∼0.1 percent of the U.S. 2015 total water withdrawal, or almost two days of freshwater withdrawal (280 B gal/day).

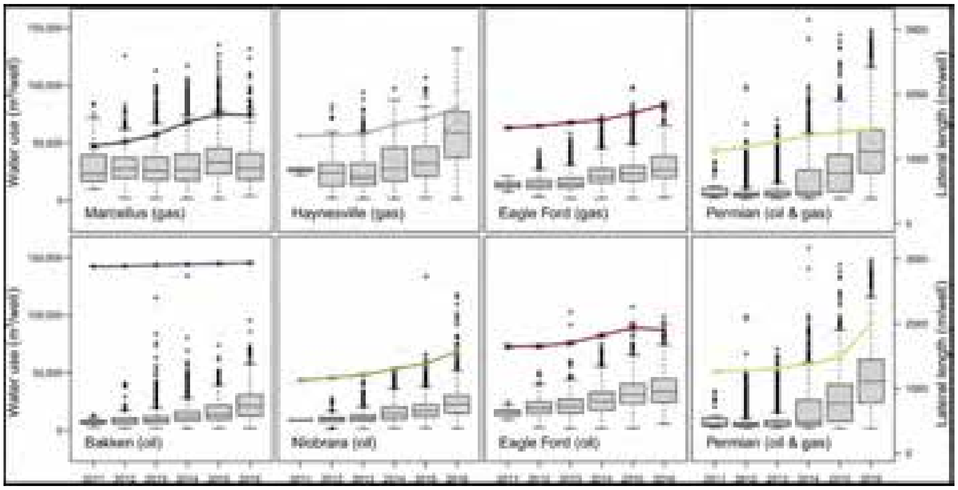
Exhibit 4-2 shows the water use for hydraulic fracturing, the amount of produced water used and oil and gas outputs from nine major plays in the United States from 2009 to 2017 (Scanlon et al., 2020a). The Eagle Ford play has used 173 B gal of combined hydraulic fracturing and produced water, at nearly a 1.83 ratio of freshwater to produced water and the Marcellus has a freshwater to produced water ratio of 5.83. Other plays use more produced water than freshwater, like Bakken, Delaware, and Barnett, where the ratios of produced water to freshwater are 1.83, 2.21, and 2.11, respectively.

Exhibit 4-2. water use in nine shale plays in the U.S.

Play	Total Length (10^6 ft)	Median Well Length (ft)	Number of Wells	Hydraulic Fracturing Water (10^9 gal)	Produced Water (10^9 gal)	Oil (10^9 gal)	Gas (10^9 gal of oil equivalent)
Bakken	114	9,580	12,036	49	75	100	22
Eagle Ford	95	6,061	17,366	112	61	103	78
Midland	49	8,575	6,461	79	44	30	14
Delaware	36	5,272	7,070	51	113	40	26
Marcellus	51	7,139	9,651	70	12	3	214
Niobrara	21	7,438	3,842	21	5	14	11
Barnett	27	5,241	7,453	35	74	1	111
Haynesville	15	6,270	3,215	30	16	0.03	107
Fayetteville	21	6,386	4,717	24	-	-	55

Exhibit 4-3 from Kondash, Lauer, and Vengosh (2018) indicate that, parallel to the increase in lateral lengths of the horizontal wells and hydrocarbon extraction yields through time, water use has also increased. The relative increase in lateral length (4–60 percent) was, however, significantly lower than the increase in water use (14–770 percent). When water use per well was normalized to the length of lateral section of the horizontal well, in almost every case among oil producing regions, an increase in water use per length of the horizontal well is observed. This pattern was most evident in the Permian region, where water use increased from 4.4 cubic meters (m^3) per meter in 2011 to 29.3 m^3 per meter in 2016 for gas-producing wells (an approximate seven-fold increase), and from 3.9 m^3 per meter in 2011 to 21.1 m^3 per meter in oil-producing wells (an approximate five-fold increase). In all cases, with the exception of the Marcellus shale play in 2016, the flowback and produced water generation also increased through time, with particularly higher rates after 2014.

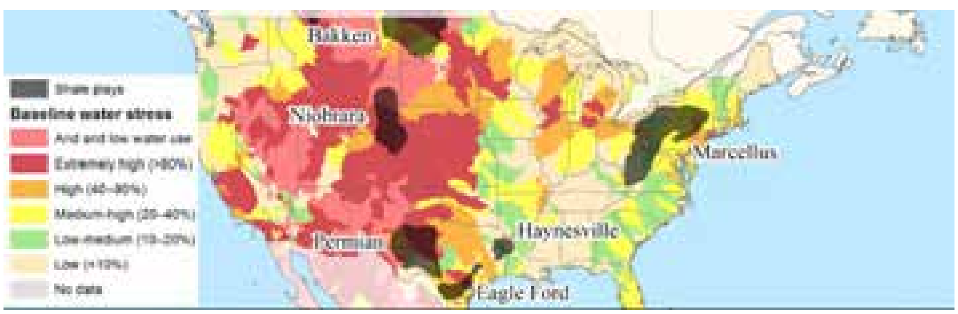
Exhibit 4-3. Water usage and lateral length by shale play



Used with permission from Kondash, Lauer, and Vengosh (2018)

Kondash, Lauer, and Vengosh (2018) also illustrate water conditions where the major plays across the United States are located, see Exhibit 4-4. The Bakken, Niobara, Permian and Eagle Ford plays are all located in arid to extremely dry climates where drought conditions have persisted for many years.

Exhibit 4-4. Baseline water stress and location of shale plays



Used with permission from Kondash, Lauer, and Vengosh (2018)

4.1.2 Water Quality

Concerns have been raised about potential public health effects that may arise if hydraulic fracturing-related chemicals were to impact drinking water supplies. The chronic oral toxicity values—specifically, chronic oral reference values (RfVs) for noncancer effects, and oral slope factors (OSFs) for cancer are available for the list of 1,173 chemicals EPA identified as "associated with hydraulic fracturing." These include 1,076 chemicals used in hydraulic fracturing fluids and 134 chemicals detected in the flowback or produced waters from hydraulically fractured wells.

EPA compiled RfVs and OSFs for these chemicals using six different governmental and intergovernmental data sources. Ninety (8 percent) of the 1,076 chemicals used in hydraulic fracturing fluids and 83 (62 percent) of the 134 chemicals found in flowback/produced water had a chronic oral RfV or OSF reported in at least one or more of the six data sources used. Thirty-six of the chemicals used in hydraulic fracturing fluids have been measured in at least 10 percent of the hydraulically fractured wells drilled nationwide (identified from EPA's analysis of the FracFocus Chemical Disclosure Registry 1.0). Eight of these 36 chemicals (22 percent) had an available chronic oral RfV. The lack of chronic oral RfVs and OSFs for the majority of these chemicals highlights the significant knowledge gap that exists to assess the potential human health hazards associated with hydraulic fracturing (Yost et al., 2016).

Ecological risks to surface waters are present throughout the well life cycle and may manifest themselves differently locally compared to regionally. These risks can also vary temporally, as development activity like surface water withdrawal may only result in a single, brief impact, while the network of roads required for accessing well pads could increase erosion and sediment runoff for years. Previous work identified the primary risks to surface water quality as sediment runoff from devegetation, leakage and spillage of chemicals into surface waters, unsustainable water withdrawal, landscape fragmentation, and insufficient treatment of oil and gas wastewater prior to discharge (Krupnick, Gordon, and Olmstead, 2013; Slonecker et al., 2012; Drohan et al., 2012; Kiviat, 2013). Unfortunately, few sites exist where baseline environmental monitoring occurred prior to hydraulic fracturing operations commencing, greatly complicating efforts to precisely quantify the impacts of hydraulic fracturing, particularly if these operations are occurring in watersheds with preexisting anthropogenic influence and a host of existing ecological stressors (Mauter et al., 2014; McBroom, Thomas, and Zhang, 2012).

The surface water risks and impacts associated with unconventional resource development vary significantly by region (Clements, Hickey, Kidd, 2012). To date, those in the Marcellus region have been examined most extensively. This scrutiny has been motivated by the nexus of regionally specific risk drivers, such as high gradient terrains that could lead to increased erosion, an abundance of small streams, highly variable in-stream flow rates, and the high salinity of produced water in the Marcellus. Moreover, during the early development of the Marcellus shale in Pennsylvania, the state permitted the disposal of hydraulic fracturing brines in municipal wastewater treatment plants. The most recent studies suggest that to reduce the human and environmental impacts associated with this original practice, the State of Pennsylvania asked companies to adopt a moratorium on the disposal of produced water in wastewater treatment plants in the state (Wilson and Van Briesen, 2012; Wilson, Wang, and Van Briesen, 2013; Warner et al., 2013a; Wilson and Van Briesen, 2013; Renner, 2009 Abdalla et al., 2016).

The rapid development of unconventional gas extraction has increased the flux of both solid and liquid waste, fluxes proportionally much greater than those generated from traditional conventional well development on a per well basis. Drill cutting wastes from unconventional wells may contain more total naturally occurring radioactive materials (NORM) than conventional wells for two reasons. Geochemically, the shale itself contains more NORM than sandstone and limestone reservoirs holding conventional reserves (Badertscher et al., 2023; Huang et al., 2017). Physically, the horizontal bore is usually much longer than the vertical bore, and a larger proportion of the drill cuttings comprises the NORM rich shale due to the directional drilling. The Pennsylvania Department of Environmental Protection (PADEP) reported drill cuttings with the following ranges: ^{226}Ra (below detection limit to 640 becquerels/kg) and ^{228}Ra (0.37–104 becquerels/kg) (PADEP, 2016).

Higher NORM values in solids and liquids resulted in higher downstream values of ^{226}Ra and ^{228}Ra as well. Stream water and sediments in areas bracketing outfalls of facilities treating waste from landfills accepting oil and gas waste indicate accumulation of NORM in the sediments. Given distance from the outfall, these accumulations are of similar magnitude to those downstream of brine treatment facilities reported in the literature (Warner et al., 2013b) and indicate additions from a low ^{228}Ra/^{226}Ra activity ratio source, consistent with Marcellus formation sources (Lauer, Warner, and Vengosh, 2018).

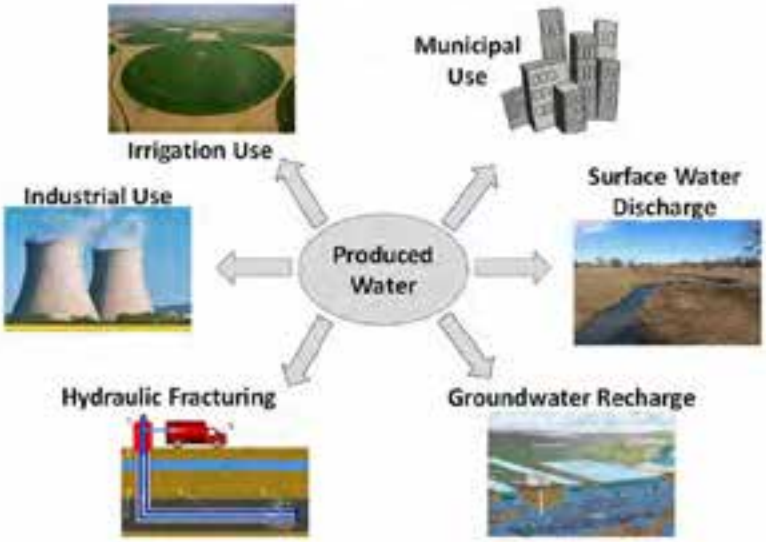
4.1.3 General Guidelines for Leading Best Practices on Water Remediation

Increasing demand for water for drilling and hydraulic fracturing in shale gas plays has driven operators to seek supplemental sources of water and alternatives to local freshwater supplies. Potential alternatives include industrial wastewater, water treatment plant outflows, abandoned mine waters, saline groundwater, and reuse of produced waters.

A 2023 report by the Groundwater Protection Council (GWPC) summarizes the most notable changes in produced water operational and management practices in each major production region (GWPC, 2023). The regions include both oil and gas production, with the Permian basin being the largest produced water region, producing 10.5 times more than the Bakken, 16.4 times more than the Eagle Ford, and 49 times more than the Appalachian region.

With many of these plays being in areas where water scarcity is an issue, reducing water consumption is critical. Therefore, produced water reuse technologies are critical as well. Once produced water is treated to fresh water or discharge standards, it can be reused. Exhibit 4-5 shows the major reuse outlets for treated produced water (Scanlon et al., 2020b).

Exhibit 4-5. Major produced water reuse outlets



Used with permission from Scanlon et al. (2020b)

When it comes to the beneficial reuse of produced water in any of the major development basins, the primary challenge to overcome is the desalination of the water by way of treatment and managing the associated products and wastes that are generated. Aside from the regulatory and liability challenges associated with the discharge of produced water, there are significant technical and economic challenges associated with large-scale produced water desalination systems. All the options for reuse shown in Exhibit 4-5 require the water to first meet a low salinity standard. The primary challenge faced by the beneficial reuse of produced water is the removal of total dissolved solids (TDS) or dissolved salt from the produced water matrix. Exhibit 4-6 shows the salinity ranges for different types of water (Horiba, 2016).

Exhibit 4-6. Different types of water salinity values

Salinity Status	Salinity (%)	Salinity (parts per trillion)	Use
Fresh	<0.05	< 0.5	Drinking and all irrigation
Marginal	0.05–0.1	0.5–1.0	Most irrigation, adverse effects on ecosystems become apparent
Brackish	0.1–0.2	1–2	Irrigation for certain crops only, useful for most livestock
Saline	0.2–1.0	2–10	Useful for most livestock
Highly Salinated	1.0–3.5	10–35	Very saline groundwater, limited use for certain livestock
Brine	> 3.5	> 35	Seawater, some mining and industrial uses exist

Produced water requires significant pretreatment prior to being subjected to any desalination process. The most prominent and proven water desalination technology deployed across the world is reverse osmosis, which becomes increasingly inefficient when TDS concentrations exceed 35,000 ppm (which is reflective of the salinity concentration in seawater). As the overwhelming amount of produced water in the United States is well above the levels to be treated by reverse osmosis, including produced water in the Permian (median TDS concentration: 154,000 ppm), this technology is not applicable.

Thermal (vapor) distillation would be considered “mature and proven” for this application. These distillation technologies typically consist of a mechanical vapor compression/mechanical vapor recompression component and have been in use for more than a decade in the oilfield treating produced water with limited acceptance due to throughput and costs. Thermal distillation technologies often require extensive pretreatment of the water before processing, including the removal of hydrocarbons, total suspended solids, and all hardness cations.

4.2 CURRENT WATER RESEARCH AND DEVELOPMENT

DOE funds R&D to advance sustainable water management technologies and approaches, responding to increased water demand from decarbonized power generation. Additionally, DOE seeks to provide alternative water resources in water-stressed areas by treating wastewaters from fossil energy activities, making those treated wastewaters available to end-users outside the fossil energy industry, and reducing environmental impacts of fossil fuel generation during the transition to clean energy. To accomplish these goals, DOE currently has R&D focused in three areas:

1. Characterization, treatment, and management of produced waters
2. Recovery of critical minerals – including rare earth elements and other resources for beneficial reuse
3. Alternative water resources and identifying opportunities to utilize them

The Produced Water Optimization Initiative (PARETO) is an optimization framework for produced water management and opportunities for beneficial use. The goal of PARETO is to develop a modeling and optimization application to identify cost-effective and environmentally sustainable produced water management, treatment, and reuse solutions.

PARETO will help with the following tasks:

- Buildout of the produced water infrastructure
- Management of produced water volumes
- Selection of effective treatment technologies
- Placement and sizing of treatment facilities
- Identification of beneficial water reuse options
- Distribution of treated produced water for reuse

The Water Management for Power Systems program will lead the critical national R&D effort directed at removing barriers to sustainable, efficient water and energy use at fossil power plants by developing technology solutions and enhancing the understanding of the relationship between energy and water resources.

DOE and NETL will work together to overcome the following challenges:

- Reduce freshwater consumption by 50 percent
- Lower the cost of treating fossil power plant effluent streams by 50 percent

The produced water characterization effort will focus on the critical national R&D effort directed at characterizing produced water associated with sustainable oil and gas development. The work proposed is aligned with DOE-FECM's program goals to reduce freshwater consumption and to recover valuable resources from both effluent and alternative influent water streams. Leveraging its core capabilities, competencies, and authorities, NETL will move to partner with universities and industry to develop and increase the commercial readiness of technology options needed to treat and manage produced water from oil and natural gas operations.

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5 Induced Seismicity

Among the many impacts of anthropogenic activity on the Earth, one that has caused particular public disquiet in recent years is "induced seismicity," that is, minor earthquakes and tremors caused by industrial processes (Grigoli and Wiemer, 2017). Earthquakes have been detected in association with both oil and natural gas production, underground injection of wastewaters (i.e., wastewater disposal), and hydraulic fracturing (Rubinstein and Mahani, 2015). Each of these processes involves injecting large volumes of fluids at various pressures into underground formations.[y] Earthquakes from human activities have happened in multiple countries, including the United States (Shultz et al., 2020).

5.1 Impacts from Induced Seismicity and Energy Technologies

The term seismic activity is generally used to describe vibrations of mechanical energy that pass through the earth, much like sound waves vibrate through the atmosphere. The seismic activity of a region is defined by the frequency, kind, and magnitude of earthquakes experienced in the region during a given period. The National Earthquake Information Center (NEIC) is the entity responsible for determining, as rapidly and as accurately as possible, the location and size of all significant earthquakes that occur worldwide. At present, the NEIC locates and publishes detailed data on the 30,000 "most significant" earthquakes that occur in each year (USGS, 2023).

While millions of earthquakes occur each year, not all are felt at the surface. Earthquakes with magnitudes of 2.0 or less generally cannot be felt at the surface by people, while earthquakes with magnitudes greater than 3.0 tend to produce noticeable shaking. Earthquakes with magnitudes greater than 5.0 are felt at the surface and have the potential to cause structural damage to buildings and property. Most earthquakes that do occur are in response to natural, yet sudden slips and shifts of large masses of rock along geologic faults.

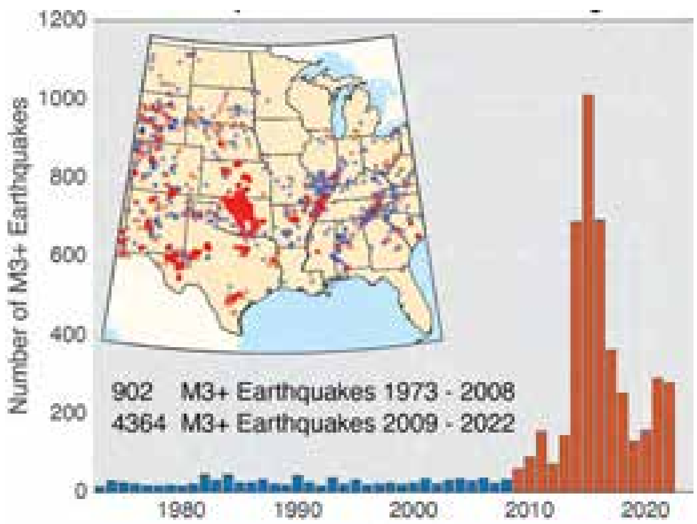
The seismicity rate in the central and eastern United States increased 40-fold from 2002 to 2012, predominantly as a result of human activities (Ellsworth, 2013; van der Baan and Calixto, 2017). This increase in seismicity rate in the central and eastern United States has largely been attributed to large-volume wastewater disposal wells injecting fluids into deep sedimentary formations (e.g., Keranen et al., 2014; Rubinstein and Mahani, 2015). Other human activities, including hydraulic fracturing (Skoumal, Brudzinski, and Currie, 2015) and carbon sequestration (e.g., Kaven et al., 2015), have induced seismicity to a lesser extent in the central and eastern United States (Skoumal et al., 2020).

Exhibit 5-1 presents the annual number of earthquakes (with a magnitude of 3.0 or larger) occurring in central and eastern areas of the United States for 1973–2022. Many of these earthquakes have taken place in areas where hydraulic fracturing has been and is actively occurring (e.g., Oklahoma) (USGS, 2022). Between 1973 and 2008, approximately 25

[y] Hydraulic fracturing involves injecting large volumes of fluids into the ground to release trapped oil and natural gas. Wastewater from oil and gas production, including shale gas production, is typically disposed of by being injected at relatively low pressures into extensive formations that are specifically targeted for their porosities and permeabilities to accept large volumes of fluid.

earthquakes of magnitude three or greater occurred on average annually. Since 2009, at least 58 earthquakes of this same size (magnitude of 3.0 or larger) have occurred annually, and at least 100 earthquakes of this same size have occurred annually since 2013. The annual number of earthquakes (with a magnitude of 3.0 or larger) peaked in 2015 when 1,010 magnitude 3+ earthquakes were recorded. Given their magnitude, most of these earthquakes are large enough to have been felt by people, yet not large enough to cause significant damage (USGS, 2022).

Exhibit 5-1. Earthquakes in the Central and Eastern U.S. 1973–2022



Source: USGS (2022)

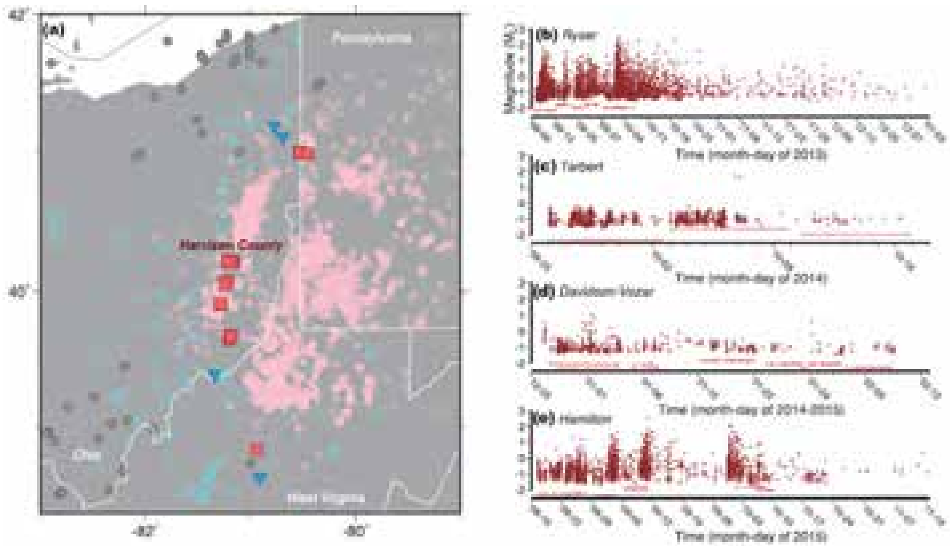
The following are examples of induced seismic events in the United States that have occurred in basins where unconventional natural gas production via hydraulic fracturing has occurred.

5.1.1 Utica and Marcellus Shales in the Appalachian Basin

The Appalachian Basin is currently the largest natural gas producing area in the United States The Marcellus and Point Pleasant Utica shale plays are both located in the Appalachian Basin and extend from New York to Kentucky. They each cover prospective areas of 190,000 and 220,000 km^2, with proven reserves of 135 and 24 Tcf of natural gas, and 345- and 210-MM barrels of oil, respectively (EIA, 2019b). Earthquakes detected in the basin as analyzed by Schultz et al. from 2013 to 2015 are presented in Exhibit 5-2.

The map on the left provides the location sequences of cataloged (magnitude > 2.0) seismic events in Ohio and neighboring states for 2010–2017. Blue triangles show earthquake sequences induced by wastewater disposal; red squares show earthquake sequences induced by hydraulic fracturing; and pink squares and blue triangles depict the horizontal and wastewater disposal wells that remain in the area. Grey circles represent earthquakes assumed to be occurring from natural causes. The four graphs on the right provide the temporal distribution of hydraulic fracturing induced seismic events for four wells in Harrison County, Ohio (Schultz et al., 2020).

Exhibit 5-2. Location and timing of induced and natural seismic events in the Appalachian Basin



Used with permission from Schultz et al. (2020)

5.1.2 Anadarko and Arkoma Basins of Oklahoma

Dramatic increases in seismic activity have been reported for areas in both central and northern Oklahoma, where the Anadarko and Arkoma Basins are located. Historically, an average of one to two ML[z] ≥ 3.0 earthquakes has occurred in Oklahoma annually. The number of ML ≥ 3.0 earthquakes occurring in the state, however, rose to over 900 in 2015 (Ellsworth, 2013).

While the seismicity rate began to decline in 2016, the yearly total seismic moment[aa] of Oklahoma remained high in response to three Mw[bb] ≥ 5.0 earthquakes occurring during the year, including the Pawnee earthquake, the largest earthquake (5.8 Mw) ever recorded for the state of Oklahoma. The seismicity rate increase has generally been attributed to the disposal of large volumes of produced water into the Arbuckle Group basin (Haffener, Chen, and Murray, 2018).

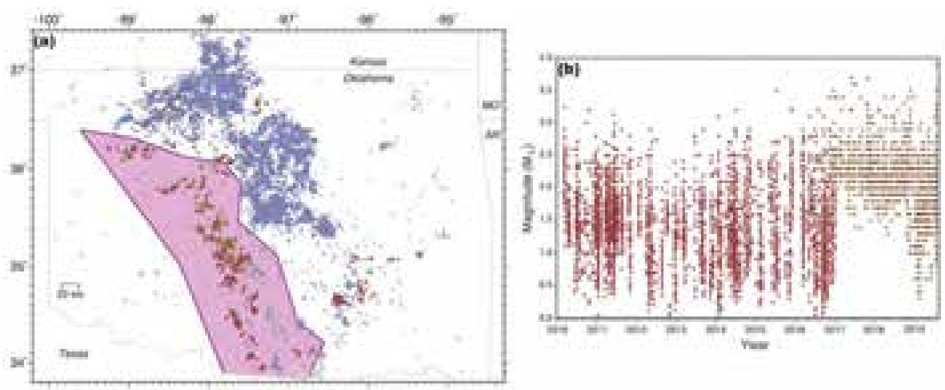
[z] ML refers to the magnitude on the Richter scale, where M stands for magnitude and L stands for local.

[aa] Seismic moment represents a measure of the size of an earthquake, depending on the area of rupture, the rigidity of the rock, and the amount of slip from faulting.

[bb] Mw is known as the moment magnitude of an earthquake. For very large earthquakes, moment magnitude gives the most reliable estimate of earthquake size.

Exhibit 5-3 shows the location (left) and magnitude (right) of induced seismic events in Oklahoma between 2010 and 2020. In the map on the left, seismic events from natural causes are represented by the blue circles, while induced seismic events are represented by the red (Skoumal et al., 2018) and orange circles (Shemeta, Brooks, and Lord, 2019). The graph on the right shows the number and magnitude of the induced seismic events over time (Skoumal et al., 2018; Shemeta, Brooks, and Lord, 2019).

Exhibit 5-3. Induced seismicity events in Oklahoma



Used with permission from Schultz et al. (2020)

5.1.3 Fayetteville Formation in the Arkoma Basin of Arkansas

Following the success of the Barnett Shale (Fort Worth Basin, Texas), the Fayetteville Formation in Arkansas became an early target for continued shale gas development in the United States. This unconventional play runs east to west across north central Arkansas, extending across nearly 150 km. By 2005, horizontal well completions in the middle to lower organic rich facies at depths typically 1–2 km were coming online and, by 2009, 0.5 Tcf of gas was being produced per year (Browning et al., 2014).

The Fayetteville Formation has a history of seismicity that dates back to before the region was developed for oil and natural gas extraction. In September 2010, a series of seismic events reaching magnitudes close to 5.0 Mw on the Richter Scale occurred along the Guy-Greenbrier Fault within the basin. Not long after, on February 28, 2011, a 4.7 Mw earthquake—the largest ever recorded—occurred within the basin. This led to concerns that even larger earthquakes could potentially occur in the area, which resulted in an emergency shutdown order for any injections being put in place by the Arkansas Oil and Gas Commission. Analysis of the seismicity, injection patterns, and pore pressure diffusion built a strong case for the activation of the Guy-Greenbrier Fault by wastewater disposal (Horton, 2012; Ogwari, Horton, and Ausbrook, 2016; Ogwari and Horton, 2016; Park et al., 2020). In the neighboring states of Oklahoma and Texas, wastewater disposal by injection is understood to be the primary driver of induced seismicity.

5.1.4 Eagle Ford Shale Play in the Western Gulf Basin of Texas

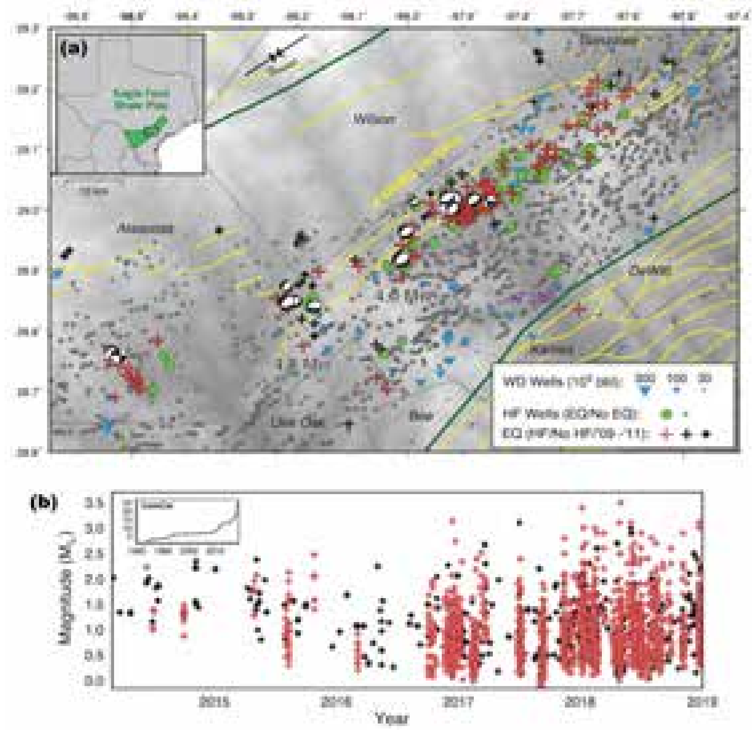
Texas has a long history of active oil and natural gas production, hydraulic fracturing, wastewater disposal, and general seismicity, some of which occurs within or near areas of pervasive faulting (see Exhibit 5-4a) (Ewing, 1990; Frohlich et al., 2016). Advancements in horizontal drilling and hydraulic fracturing since 2008 have prompted the Eagle Ford shale play to focus on hydrocarbon production from the Upper Cretaceous Eagle Ford and Austin Chalk Formations (Frohlich and Brunt, 2013; Martin et al., 2011; Pearson, 2012; RRC, 2019).

In 2018, the rate at which ML ≥ 3.0 earthquakes occurred in the Eagle Ford shale play was 33 times higher than background levels (3 earthquakes per 10 years during 1980–2010; see Exhibit 5-4b). Fasola et al. (2019) investigated seismicity that has occurred since 2014, in an effort to identify how hydraulic fracturing has contributed to seismicity within the play. Comparing both times and locations of hydraulic fracturing to a catalog of seismic activity, Fasola et al. (2019) suggest more than 85 percent of the seismicity that occurred was spatiotemporally correlated with hydraulic fracturing. More specifically, there were 94 ML ≥ 2.0 earthquakes correlated with 211 hydraulic fracturing well laterals.

Exhibit 5-4a provides a map from the Texas Seismological Network highlighting earthquakes (crosses) and focal mechanisms (beach balls) that have occurred since 2017. Hydraulic fracturing wells are indicated by black circles in Exhibit 5-4. Correlated earthquakes and hydraulic fracturing wells are displayed as red plus signs and green circles, respectively. Black diamonds show the earthquakes that occurred during 2009–2011 (Frohlich and Brunt, 2013). Purple square shows the seismic station (735B) used for template matching. Wastewater disposal wells are provided as teal triangles sized by median monthly volumes. Arrows show regional orientation (Lundstern and Zoback, 2016). Faults (Ewing, 1990) are in yellow.

Exhibit 5-4b provides the magnitudes of the various earthquakes both correlated and not correlated with hydraulic fracturing that occurred annually after 2011 within the play (the black and red plus signs shown in Exhibit 5-4a). The inset shows the cumulative number of earthquakes (magnitude ≥ 3.0) occurring in the area, available from the USGS Comprehensive Catalog.

Exhibit 5-4. Locations and timings of Eagle Ford hydraulic fracturing induced events



Used with permission from Schultz et al. (2020)

5.2 Induced Seismicity Research and Development

State regulators have long been focused on identifying the precise location and magnitude of earthquakes and determining their cause. When earthquakes can be linked to wastewater injection, regulators respond by ordering operators to cease or limit either injection rates and/or water volumes in nearby wells (EPA UIC National Technical Workgroup, 2015). Many regulators also require that new injection wells avoid areas near known active faults. In Oklahoma, these techniques have effectively reduced the number of felt earthquakes.

Similar procedures have been applied to hydraulic fracturing operations in some states. That is, when earthquakes are detected, operations are either modified or suspended (AGI, 2017). Oklahoma, Texas, and Ohio have all taken steps to mitigate induced seismicity linked to hydraulic fracturing.

In Texas, the state's Center for Integrated Seismicity Research (TexNet) is charged with monitoring, locating, and cataloging seismicity across the state. Capable of detecting and locating earthquakes with magnitudes ≥ 2.0, TexNet's backbone network improves investigations of ongoing sequences of seismic activity by deploying temporary seismic monitoring stations and conducting site-specific assessments (Young et al., 2017). TexNet continues to conduct fundamental and applied research to better understand both naturally and potentially induced seismic events that are occurring across the state of Texas, their associated risks, and potential strategies for communicating with stakeholders and responding to public concerns raised regarding seismicity (Young et al., 2017).

Through the DOE-funded RPSEA, University of Texas researchers analyzed data collected by the portable NSF EarthScope USArray program to evaluate seismic hazards in different oil and gas producing regions. Results show that regions need to be studied individually before crafting regulations for injection management strategies due to the following results:

- In the Barnett shale play region, earthquakes occur near high volume injection disposal wells.
- In the Eagle Ford play region, earthquakes are not near injection wells, but follow increases in extraction of water/petroleum.
- In the Bakken play region, there are high volume injection wells but almost no earthquakes.
- There were eight times as many earthquakes in the Fort Worth Basin as reported by the USGS during 2009–2011, based on data collected by the transportable USArray.

Also funded through RPSEA, the Oklahoma Geological Survey in collaboration with the University of Oklahoma, the Oklahoma Secretary of Energy and Environment, and industry have:

- Improved the accuracy of locating earthquakes by adding permanent and portable seismic monitoring stations, the data from which is publicly available through the Oklahoma Geologic Survey's Oklahoma Earthquake Catalog.
- Documented a major increase in salt-water disposal in areas within seismically active areas.
- Mapped previously unidentified basement faults in Oklahoma that are now publicly available in open file maps
- Developed 4-D integrated models for risk assessment (Office of Oil and Natural Gas, 2016)

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6 Land Use and Development

Land presents a critical yet often overlooked constraint to energy development, including the development of domestic natural gas. The growing land use footprint of energy development, termed "energy sprawl," likely causes significant habitat loss and fragmentation with associated impacts to biodiversity and ecosystem services (McDonald et al., 2009). Natural gas is growing as a transition fuel during the grid decarbonization process in the United States, making an understanding of its land use implications a critical and necessary consideration (Dai et al. 2023).

Expanding energy development is now the primary source of anthropogenic land cover change in natural ecosystems in North America (Allred et al., 2015; Trainor, McDonald, and Fargione, 2016), including eastern deciduous forests, boreal forests, prairie grasslands, sagebrush-steppe, and deserts (Copeland, Pocewicz, Kiesecker, 2011; McClung and Moran, 2018; Appiah, Opio, Donnelly, 2019). Land use and development issues associated with natural gas production include local surface disturbance; cumulative landscape impacts; habitat fragmentation; and increased traffic, noise, and light.

The Citizens Marcellus Shale Coalition (CMSC) (2011) explored two issues related to impacts of shale gas production on public lands and the other industries that rely on these lands. They also explored impacts on private property rights. CMSC stated that shale gas development must consider the cumulative impacts on state parks and forests and on timber and tourism industries as part of ensuring responsible stewardship of public resources. Property rights and environmental degradation are a growing public concern, and eminent domain laws, drill spacing requirements, and grouping of leased lands could help protect these rights. These findings are still relevant to current natural gas extraction.

6.1 Surface Disturbance and Landscape Impacts

The infrastructure needed to support the supply chain of electricity produced from natural gas involves production sites (production pads and their access roads), transportation facilities (e.g., gathering and transmission pipelines for natural gas), processing facilities, and power plants (end-use) (Dai et al., 2023). Such activities can disturb the Earth's surface, the impacts of which can extend over large areas and result in habitat fragmentation that impacts both plant and animal species. Mitigation options include adoption of best practices for site development and restoration, avoidance of sensitive areas, and minimization of impacts to disturbed areas.

Dai et al. (2023) used machine learning, remote sensing, and geographic information systems to obtain spatially explicit information on the land required to support natural gas production for use in power plants. Their analysis considered land use across five life cycle stages of natural gas produced for electricity production from wells (production stage), natural gas transportation via gathering pipelines (gathering stage), natural gas processing (processing stage), natural gas transportation via transmission pipelines (transmission stage), and gas consumption as fuel through combustion in gas-fired power plants (use stage).

For the production stage, Dai et al. (2023) mapped land-use for 100,009 wells located at 75,915 different well pads. Among the 100,009 wells examined, 31,716 were co-located. In non-

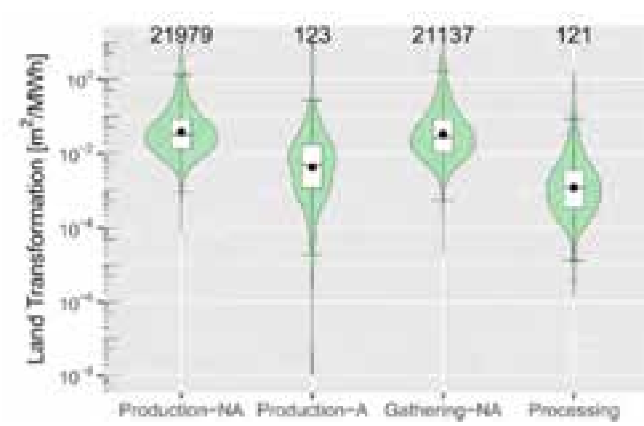
agricultural areas, results suggest vertical wells occupy ~4,000 square meters (m^2) less land per site than horizontal-/directional-drilled wells. During the gathering stage in both agricultural and non-agricultural areas, sites with horizontal-/directional-drilled wells require ~230 meters less pipeline in length on average than sites with vertically drilled wells. Whereas due to the requirement for larger width of right-of-way, the extent of land used is almost doubled for sites with horizontal-/directional-drilled wells than those with vertical wells. Results from Dai et al. (2023) are summarized in Exhibit 6-1.

Exhibit 6-1. Land use for the production, transportation, and processing of natural gas for use in gas-fired power plants

Stage			Unit	Average
Production	Agricultural	Directional	m^2 per site	9,346
		Vertical	m^2 per site	2,100
	Non-agricultural	Directional	m^2 per site	18,170
		Vertical	m^2 per site	14,090
Transportation by pipeline	Length	Directional	m^2 per site	597
		Vertical	m^2 per site	818
	Area	Directional	m^2 per site	20,157
		Vertical	m^2 per site	10,128
Processing			m^2 per (MM cubic feet per day)	4,318

Exhibit 6-2 from Dai et al. illustrates the land transformation by stage, finding that production in non-agricultural areas utilizes more land than agricultural areas.

Exhibit 6-2. Land transformation in natural gas production



Note: NA = non-agricultural area, A = agricultural area

Used with permission from Dai et al. (2023)

Notably, technological advancements will play a significant role in decreasing the amount of land that will be transformed during the life cycle stages of production, gathering, and consumption of natural gas—for both vertical and horizontal/directional wells. Directional drilling technology enables more than 20 wells to be drilled in a single pad, and each well could have a comparable amount of lifetime production. As a result, the total amount of production per site with directional-drilled wells can be an order of magnitude higher than the conventional sites with vertical drilled wells, which dramatically lowers the land transformation for production and gathering (Dai et al., 2023).

6.2 Habitat Fragmentation

The development of drilling sites for natural gas production can disrupt the habitat of both plant and animal species in several different ways. For example, habitat fragmentation can occur when infrastructure must be installed, or land clearing must take place to allow access to a well location. Land area that is occupied by well pads and the construction of pipelines are two of the leading causes of habitat fragmentation (Cooper, Stamford, and Azapagic, 2016; Langlois, Drohan, and Brittingham, 2017). The land area occupied for shale gas extraction typically can be reduced through the use of multi-well pads at one site, which have a surface footprint (and water use) per well two to four times lower than that of single-well pad sites (Manda et al., 2014).

The construction and installation of the infrastructure necessary for natural gas development can lead to a habitat being converted from a large contiguous patch of similar environments to several smaller, isolated environments. When contiguous core habitats are fragmented into smaller patches, many sensitive species are unable or unwilling to cross non-habitat regions to reach alternative habitat patches. While habitat loss can have an immediate impact on wildlife population, the ecological response to fragmentation is lagged, and affects different species at varying timescales (Makki et al., 2013).

A secondary impact of fragmentation is the creation of edges. Edges are generally defined as the 100 meters between core forest and non-forest habitat (PADEP, 2014; Kargbo, Wilhelm, and Campbell, 2010; Johnson et al., 2010). New edges affect the physical or biological conditions at the ecosystem boundary and within adjacent ecosystems (Fischer and Lindenmayer, 2007). Edge effects are believed to be detrimental by increasing predation, changing lighting and humidity, and increasing the presence of invasive species (Johnson et al., 2010).

Exhibit 6-3 provides a schematic depicting the habitat loss and fragmentation from natural gas production. Exhibit 6-3 progresses from infrastructure development that has quantifiable land impacts leading to temporally extended land changes—impacts that account for habitat loss and fragmentation.

Exhibit 6-3. General procedure for depicting land disturbance from natural gas extraction

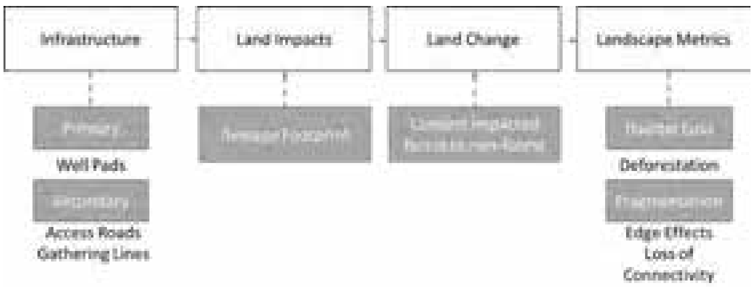
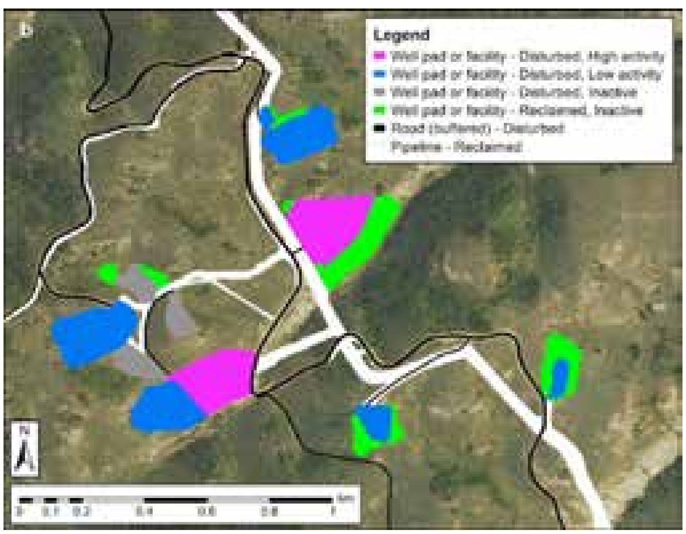


Exhibit 6-4 provides an example of energy infrastructure features digitized from 2013 National Agricultural Inventory Program satellite imagery overlaid with well locations reported in Colorado Oil and Gas Conservation Commission (COGCC) data. Each mapped feature (or portion thereof) was classified by type (well pad, facility, road, or pipeline) and by surface type (disturbed or reclaimed), and well pads and facilities (or portions thereof) were assigned an activity status (high, low, or inactive) (Walker et al., 2020).

Exhibit 6-4. Footprint of a well pad and surrounding infrastructure



Used with permission from Walker et al. (2020)

Each region where natural gas extraction takes place has unique species and habitat therein. Within those species, some are more greatly affected than others, whether it be core habitat fragmentation or edging.

Long-term effects of shale gas production on habitat disturbance will have to be evaluated as the development of these resources continues. Mitigation measures such as avoidance, best management practices, and prompt reclamation of the drilling site have been put forward as ways to best minimize the possible impacts that shale gas production may have on habitats. Habitat disruption can also result from a lack of surface water availability in response to withdrawals to support natural gas production and from erosion and chemical spills.[cc]

6.3 NOISE, LIGHT, AND TRAFFIC

Natural gas development processes are associated with both noise and light pollution, which can contribute to stress among those living in nearby communities (Down, Armes, Jackson, 2013; Korfmacher et al., 2013; Peduzzi et al., 2013; Witter et al., 2008a; Witter et al., 2008b). Construction, vehicles, drilling, compressors, flaring, and other processing equipment and facilities can all pollute by producing excessive noise and continuous illumination (Cleary, 2012).

6.3.1 Noise Pollution

A health impact assessment in Colorado identified noise pollution as an area of concern and noted that it occurs during drilling and completion operations, flaring, and because of vehicular traffic (Witter et al., 2013). Workers can be exposed to noise through many sources on site, including diesel engines, drilling, generators, mechanical brakes, heavy equipment operations, and radiator fans (Witter et al., 2014); therefore, hearing impairment is a noise-related health concern for workers on site.

A 2010 study using biomonitoring from Texas found residents reporting concerns about odors and noise apparently related to shale gas well and compressor station operations, although this was a separate, independent component from the biomonitoring portion designed to address residents' concerns (Texas Department of State Health Services, 2010). While the authors noted that it was difficult to determine if the levels were above acceptable limits that may be harmful to human health, and that noise may affect quality of life, this is speculative because noise levels were not measured to establish decibels of noise in the study area.

Noise standards for a single well pad may be met; however, the cumulative effects of multiple operations in one area might exceed these established decibel levels. In terms of setback distances, some noise regulations distinguish between maximum decibels for day and night, while others distinguish between maximum decibels for certain phases of the operation such as drilling, fracturing, and production; however, there is often variability and, in some areas, it is suggested that distances are set as monitoring points, not necessarily points indicative of being protective of health (Fry, 2013).

6.3.2 Light Pollution

Light pollution has significant implications for the environment and public health, and its effects have become more pronounced over time due to the increasing extent and radiance of artificially lit areas (Kyba, 2017). Substantial economic values have been attached to affected

[cc] The potential water use implications of natural gas are discussed in Chapter 4 – Water Use and Quality.

outcomes, such as biodiversity, recreation, and public health. With respect to human health, artificial lights at night are associated with sleep deprivation and mental health (Patel, 2019; Xiao, 2020); sleep deprivation, in turn, has been shown to reduce cognition and labor market productivity, as well as elevate mortality risks associated with dementia, heart attacks, and vehicle accidents (Hafner et al., 2017; Paksarian et al., 2020; Ma et al., 2020; Jin and Ziebarth, 2020; Prats-Uribe, Tobías, and Prieto-Alhambra, 2018.). A study in Australia quantified the financial and non-financial costs of inadequate sleep in 2016–2017 to be $45 B (Hillman et al., 2018) and another study estimates that $680 B is lost due to sleep deprivation across five Organisation for Economic Co-operation and Development (OECD) countries (Hafner et al., 2017; Boslett, 2021).

The impacts of light pollution also extend to human health and well-being. Artificial light disrupts melatonin secretion and circadian rhythm (Haim and Zubidat, 2015) with corresponding changes in mood regulation, depression, and sleeping disorders (Cho et al., 2016). Light pollution-driven changes in circadian rhythms may also have contributed to recent growth in obesity and metabolic dysfunction (Fonken et al., 2010). Growing laboratory and epidemiological evidence also support the long-hypothesized relationship between nighttime light exposure and cancer rates (Kerenyi, Pandula, and Feuer, 1990; Kloog, et al., 2010; Schwimmer et al. 2014; Jones, Pejchar, and Kiesecker, 2015).

Light pollution also has significant consequences for wildlife populations. It affects nighttime behavior and habits of terrestrial (Bennie et al., 2015) and marine (Davies et al., 2013) wildlife populations, particularly for species that use sunlight or moonlight for guidance. It disrupts natural sleep and reproductive cycles, geographical orientation, and predator-prey relationships (Longcore and Rich, 2004). Other effects of light pollution include changes in bird singing behavior (Miller, 2006), estrus patterns in nocturnal primates (LeTallec, Théry, and Perret, 2015), insect pollination (MacGregor et al., 2015), and fish biological rhythms (Brüning et al., 2015). These impacts have led to ecosystem-wide changes in biodiversity and growing disparities between entire taxonomic groups (Davies et al., 2013).

While there is some work speculating that light pollution associated with shale development induces psychosocial stress (Fisher et al., 2017), sleep and mental health issues (Casey et al., 2018), and adverse impacts to local ecosystems (Kiviat, 2013), the literature directly connecting the recent resource boom to light pollution is extremely limited. No work has documented the causal impact of U.S. shale development on light pollution.

6.3.3 Traffic

Traffic may increase in any given area because of unconventional natural gas development, but the magnitude of this increase has not been studied in depth. The phases of development that require the most traffic load involve well pad construction, drilling and well completion, and pipeline construction (Witter et al., 2014). It appears that changes in traffic patterns will be dependent upon the area and either the individual project or the cumulative effects of multiple projects in an area. Industrial truck traffic can be detrimental to health-related air quality due to vehicle exhaust, as well as pose an increased risk of motor vehicle crashes.

In the *Revised Draft Supplemental Generic Environmental Impact Statement on The Oil, Gas and Solution Mining Regulatory Program*, the New York State Department of Environmental Conservation (NYSDEC) identified temporary but adverse noise and visual impacts from construction activity and increased truck traffic among the potential land-use environmental impacts associated with natural gas production (Witter et al., 2014). Significant adverse impacts in terms of damage to local and state roads could also result. Among mitigation measures described for environmental impacts, NYSDEC suggests imposing measures to reduce the adverse noise and visual impacts from well construction. A transportation plan could also be required that would include proposed truck routes and assess road conditions along the proposed routes. Exhibit 6-5 tabulates the number of truck trips for a typical shale gas well (Massachusetts Institute of Technology [MIT], 2011).

Exhibit 6-5. Truck trips for a typical shale gas well drilling and completion

Activity	1 Rig, 1 Well	2 Rigs, 8 Wells
Pad and Road Construction	10–45	10–45
Drilling Rig	300	60
Drilling Fluid and Materials	25–50	200–400
Drilling Equipment (casing, drill pipe, etc.)	25–50	200–400
Completion Rig	15	30
Completion Fluid and Materials	10–20	80–160
Completion Equipment (pipe, wellhead, etc.)	5	10
Fracturing Equipment (pump trucks, tanks, etc.)	150–200	300–400
Fracture Water	400–600	3,200–4,800
Fracture Sand	20–25	160–200
Flowback Water Disposal	200–300	1,600–2,400
Total	**1,160–1,610**	**5,850–8,905**

The large volumes of water involved in hydraulic fracturing operations can create high volumes of road traffic given the majority of the water used for fracking is transported by truck. It should be noted that the large number of traffic movements shown in Exhibit 6-5 are worst-case estimates. In particular, re-use of flowback wastewater significantly reduces the amount of road traffic associated with hauling water, which represents much of the traffic movement. Furthermore, large-scale operators are also using pipelines to transport water to the site, substantially reducing the amount of road traffic (MIT, 2011).

The Eagle Ford Shale Task Force Report for the RRC identified increased traffic and deterioration of roads and bridges among the infrastructure impacts from shale gas development (Porter, 2013). Exhibit 6-6 lists estimates of the number of truck-trips-per-shale-gas-well in the Eagle Ford (Porter, 2013).

Exhibit 6-6. Loaded truck trips per gas well

Activity	Number of Loaded Trucks
Bring well into production	1,184
Maintain production (per year)	Up to 353
Re-fracturing (every 5 years)	997

These impacts are enough of a concern that the task force considered alternative financing methods to help meet the increased demands on roads and bridges (Porter, 2013).

Upadhyay and Bu (2010) surveyed the visual impacts of Marcellus drilling and production sites in Pennsylvania. They reviewed the drilling process, assessed direct visual impacts, and compared the results to the impacts of other technologies (e.g., windmills and cell towers). They also studied drill-pad density from map and aerial perspectives to examine the likelihood of seeing drill towers across a landscape, and the modeled potential impacts for increased drilling, making the following conclusions:

- Serious impacts from light and noise are a potential problem within a small radius of drilling sites.
- Indirect impacts like increased truck traffic, equipment storage, and temporary structures compose the most salient visual impacts, rather than the drill pads themselves.
- Timelines for site restoration of visual impacts vary significantly.

Upadhyay and Bu (2010) recommended that visual impacts be addressed during the siting and design phase and that nighttime impacts could be avoided by pointing lights downward.

The Resources for the Future (RFF) (2013) report also gave several options in their survey of experts under the category of community disruption. Included in this category, as well as in the habitat fragmentation section, were such risks as light pollution, noise pollution, odor, and road congestion. The industry respondents identified a number of these community disruptions as risk pathways of high priorities, while the other respondent groups identified more conventional (e.g., air pollution, water pollution) risks.

6.4 Reducing Potential Land Use Impacts

Linear infrastructure on private land contributed to the greatest loss of core forest. Unlike private land, the majority of pipelines on public land were collocated with roads, which likely reduced habitat fragmentation. Large public landowners can negotiate with a relatively small number of gas operators compared to private landowners (PADEP, 2016); therefore, individual landowners can make deals with different operators such that two different operators end up working in close proximity and duplicating infrastructure on private land rather than public land.

6.4.1 Mitigation Options for Habitat Fragmentation Impacts

Mitigation strategies related to pipelines enacted by state agencies have shown that fragmentation on public lands has been reduced more than on private lands, especially when multiple mitigation strategies are implemented on public land with the goal of reducing surface disturbance and impacts to forest. For example, the Pennsylvania Department of Conservation & Natural Resources (PADCNR) can limit the number of well pads per leased track (PADCNR, 2014). This method constrains development intensity (i.e., pad density) and encourages operators to increase the number of wells per pad, thereby maximizing per well drainage and efficiency (DOE, 2016). A widely implemented mitigation policy on state forest land requires gas infrastructure to utilize existing surface disturbance whenever feasible, including road networks, right-of-way corridors, or abandoned mine lands (PADCNR, 2014).

Similarly, Abrahams, Griffin, and Matthews (2015) found that requiring pipelines to follow existing roads prevented further fragmentation in a core forested region while allowing full extraction of the shale resource. Collocation is widely accepted as an effective mitigation strategy to reduce surface impacts (Bearer et al., 2012; Racicot et al., 2014); however, it rarely occurs on private land.

6.4.2 Reducing Light Pollution

Even two decades after the establishment of designated programs by NGOs to recognize and certify the quality of night skies and nighttime darkness resources, the very notion of what a “dark sky” is remains unsettled from a scientific standpoint (Crumey, 2014); while appropriate instrumentation can quantify night sky brightness, it cannot properly account for the human aesthetic experience of natural night. However, various lines of research increasingly suggest that unsafe thresholds of exposure to artificial light at night in terms of intensity, duration, wavelength, and timing likely exist for humans, plants, and animals. In this sense, light-sensing technologies applied in the field could effectively serve as “dosimeters” for monitoring these exposure parameters (Barentine, 2019).

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