From: Robert Wallace
Sent: Wed, 2 Aug 2023 02:59:28 +0000
To: Harker-Steele, Amanda J (NETL); Easley, Kevin
Cc: Skone, Timothy
Subject: [EXTERNAL] Questions with respect to comments in paper
Attachments: Draft_Env.Review_Task4_LNG_LNGRegAnalysisSupport_FWP-DraftPreDecisional_7_28_23-2 - bw.docx

Good evening,
Please see the list of questions I have with respect to reviewer comments below. I am also attaching my copy of the commented report where I reply to many of the comments that I do not feel we need to discuss in the meeting in-depth but am willing to have more conversation about if you feel the need.

Chapter	Page #	Commentor	Comment	My question
4.1	49	Kevin Easly (HH)	Note about induced seismicity, which has become one of the main reasons for regulatory "Sticks" that are driving technological innovation.	There is an Induced Seismicity section. Is the reviewer requesting a cross reference to this section, or state that removing excessive groundwater could lead to induced seismicity?
4.3	57-59	HH, Kevin, Tim	Multiple comments	I believe the Wednesday 8/2 meeting will cover this subject.
5.2	67-69	Kevin	Multiple comments	Let's discuss which ones go away with the removal of regulations within chapters and which ones stay, or get moved to Chapter 1.
6	73	Amanda, Kevin	Remove or keep 2011 in reference	

6.4.1	80-81	Kevin	Issue with older reference dates.	

Robert Wallace | **Principal Engineer**
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KEYLOGIC

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

All images in this report were created by NETL, unless otherwise noted.

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*

[1]National Energy Technology Laboratory (NETL)
[2]NETL support contractor
*Corresponding contact: Amanda.HarkerSteele@netl.doe.gov

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 [ST5R4]: Understood - thank you.

Suggested Citation:
H. Singh, M. Marquis, O. Bostick, R. Wallace, and A. Harker Steele, "Potential Environmental Impacts Associated with Unconventional Natural Gas," National Energy Technology Laboratory, Pittsburgh, July 21, 2023.

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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.

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~~le~~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:[b]

- **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

[b] 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.

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

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).

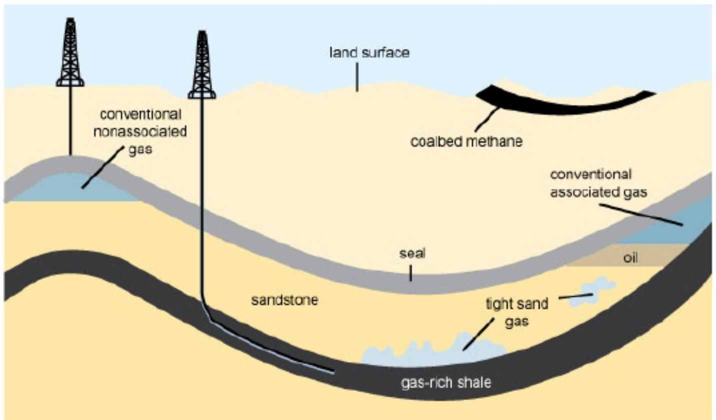
The i~~I~~nternal pressure caused by the fracturing of the rock formation also releases fluid, which travels to the surface through the wellbore. This fluid is commonly referred to as "flowback" or "produced water" and may contain the injected chemicals in addition to any naturally occurring materials 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 sectio n,~~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).

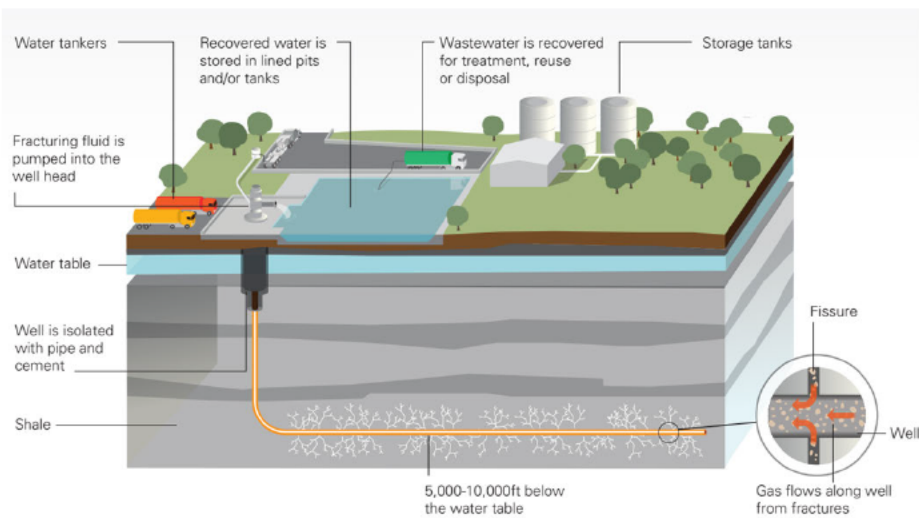
[c] The specific types of chemical additives used, and the proportions of each, depend on the type of rock formation that is being fractured. Additives function as friction reducers, biocides, oxygen (O_2) scavengers, stabilizers, and acids, all of which are necessary to optimize production. The composition 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.

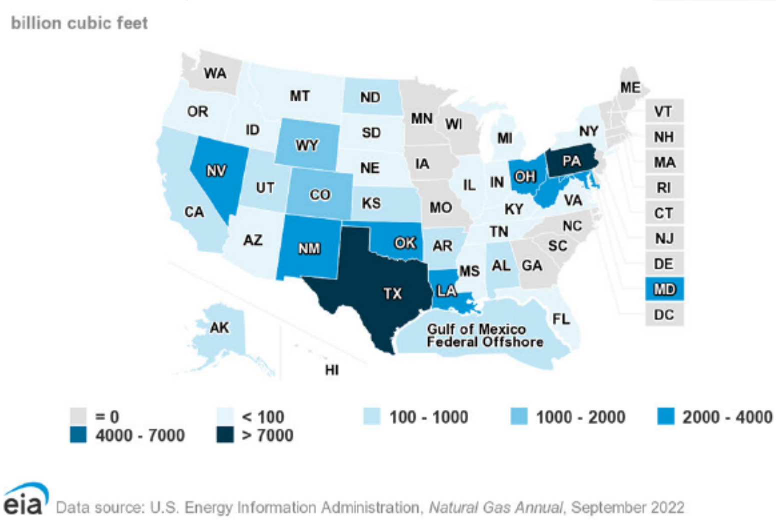
1.1.1 Liquefied Natural Gas

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~~5~~ 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.

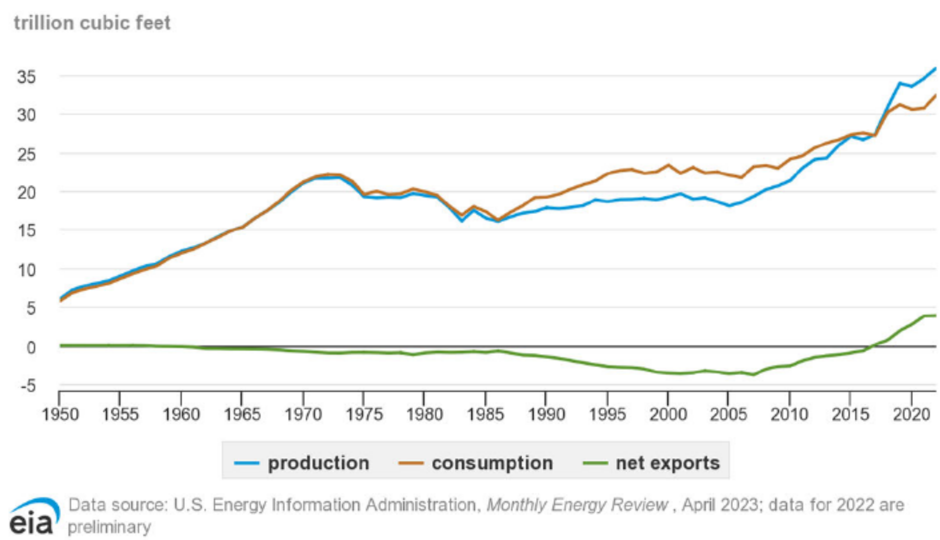
Commented [HSAJ27R25]: Add paragraph on 2021 dry production national volume to set up explanation.

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.

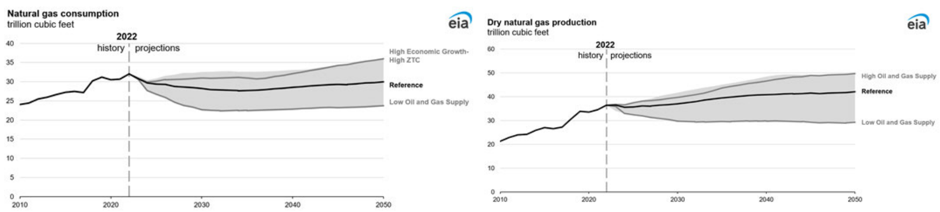
Exhibit 1-4. U.S. natural gas consumption, dry production, and net exports (1950–2022)



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).~~

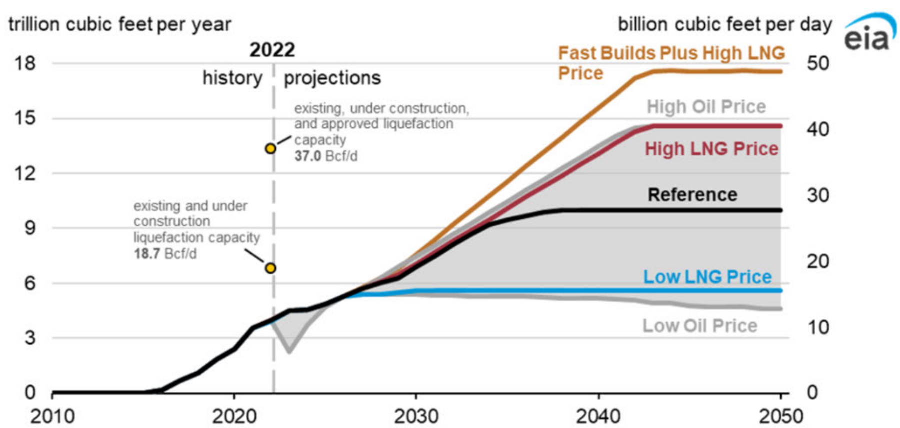
~~*Exhibit 1-5. Natural gas consumption and dry production projections through 2050*~~



~~*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*~~



Data source: U.S. Energy Information Administration, *Annual Energy Outlook 2023 (AEO2023)* and LNG Capacity Tracker
Note: Existing, under construction, and approved LNG capacities are baseload capacities. Shaded regions represent maximum and minimum values for each projection year across the AEO2023 Reference case and side cases.

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

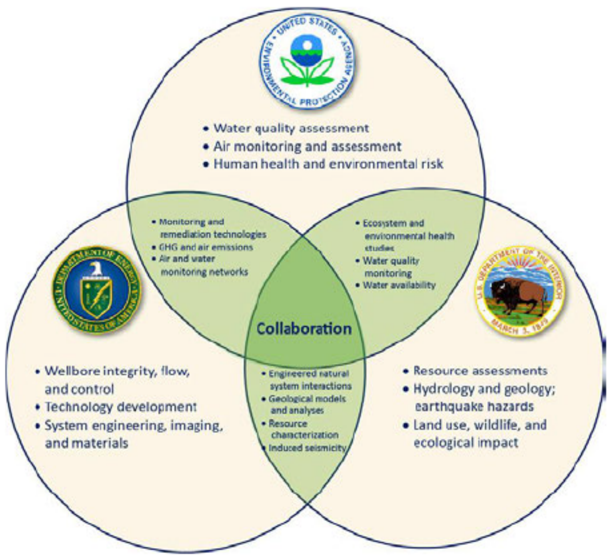
1.3 U.S. Regulatory Framework and Federal Research and Development Programs

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 natural gas environmental impacts ~~both associated and not associated with natural gas production.~~ 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 (CAA).

Federal agencies including EPA, DOI's Bureau of Land Management (BLM), the National Park Service (NPS), the Occupational Safety and Health Administration (OSHA), 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[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	✓	●	●[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 SO_2 only; [2]Covered for VOCs only

Source: EPA

EPA's Greenhouse Gas Reporting Program (GHGRP) requires reporting of ~~to be reported~~ 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 other ~~person~~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 of 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 (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. ~~, 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.[e]

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~~lean 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~~atural 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 (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 (USCG), 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

[e] "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 (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. ~~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 (RFI) ~~P~~was issued by FECM to obtain input to inform DOE's research and development (R&D) ~~P~~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 RFI~~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, ~~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.

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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2 Greenhouse Gas Emissions and Climate Change

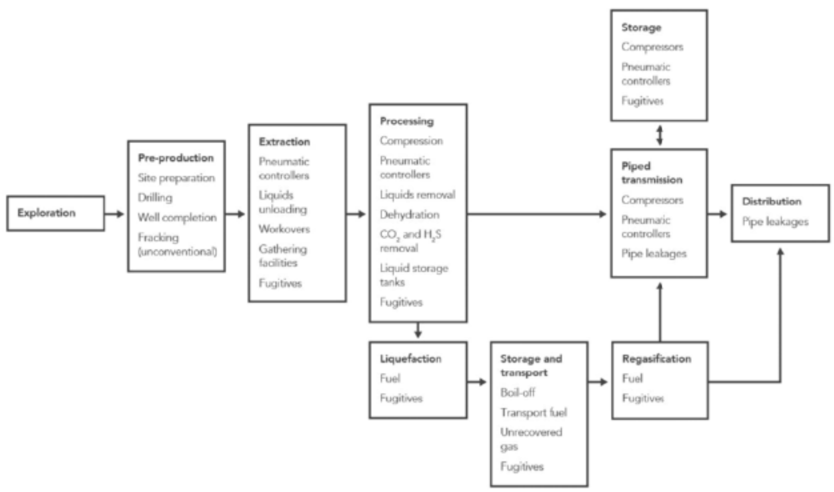
CH_4 and CO_2 emissions from the LNG life cycle ~~and natural gas end uses~~ vary widely across different regions and supply chains. This section presents a review of contemporary (2014 and after) life cycle analysis (LCA) as it pertains to LNG and natural gas GHG emissions.

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 ~~atmosphers~~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.

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).

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.

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):

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.

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.

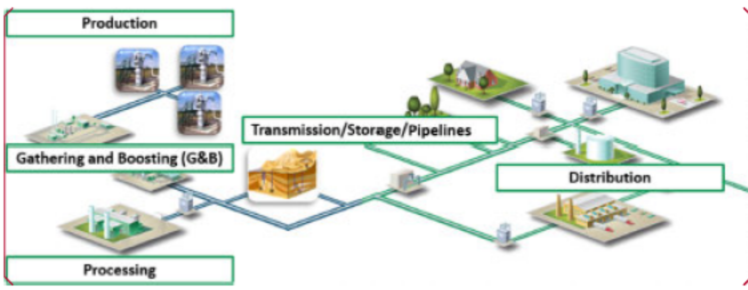
[g] The GHG results in the NETL (2019) report supersede the GHG results in the previous NETL reports.

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.

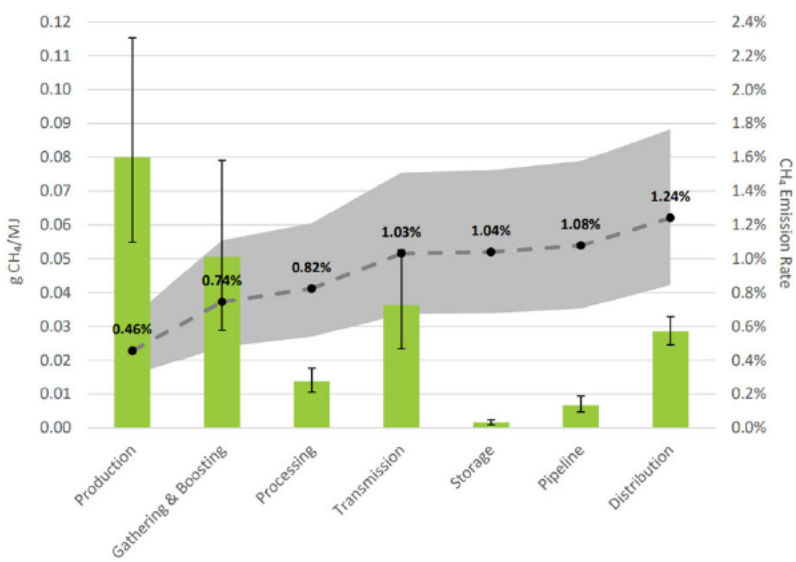
EPA estimates oil and natural gas CH_4 emissions in the annual Greenhouse Gas Inventory (GHGI) it produces. The GHGI uses a bottom~~s~~-up approach to estimate national CH_4 emissions.

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. In Exhibit 2-4, ~~T~~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, respectively, represent the error bars in this analysis, and the shaded grey area represents the 95 percent mean confidence interval.

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



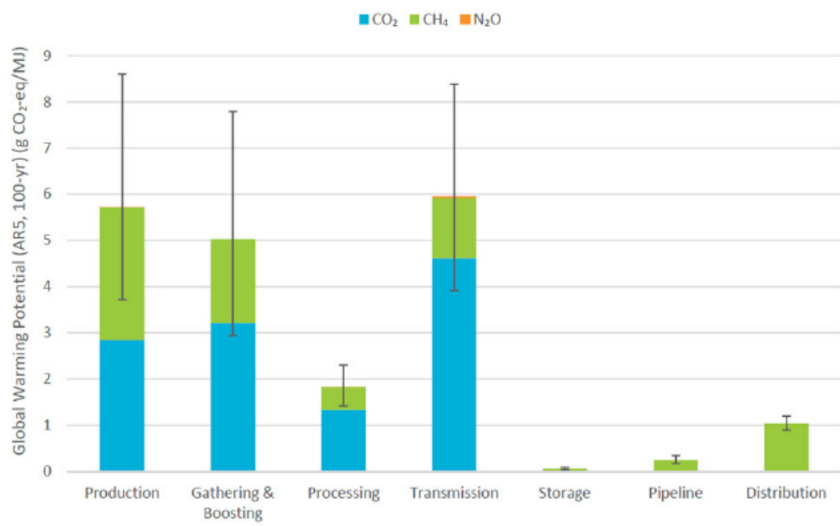
Commented [TS75]: Add citation

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.

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



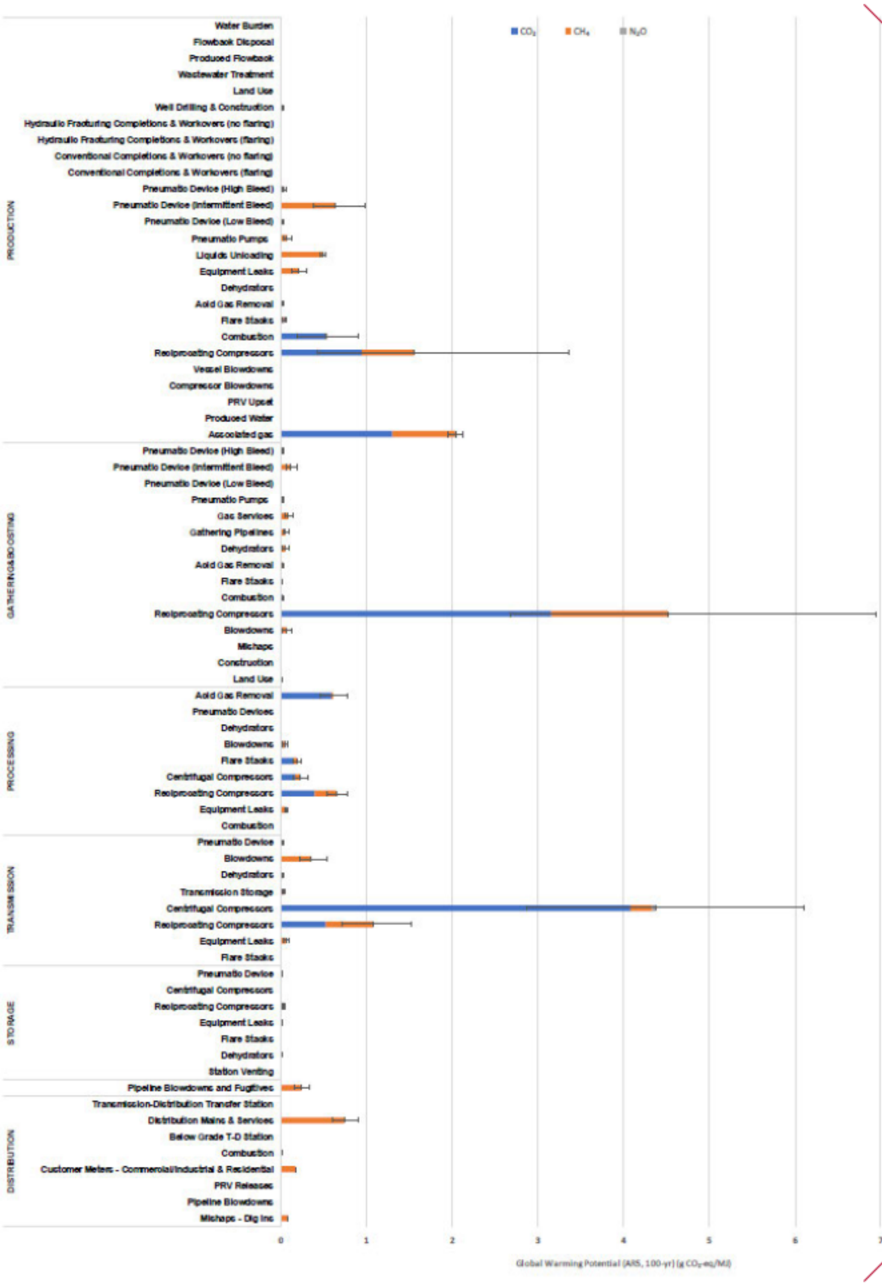
Key drivers of GHG emissions results for the entire natural gas supply chain are illustrated in Exhibit 2-5 (NETL, 2019). Pneumatic devices and compression systems represent a significant portion of the total life cycle GHG emissions associated with the natural gas supply chain (NETL, 2019). Pneumatic 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

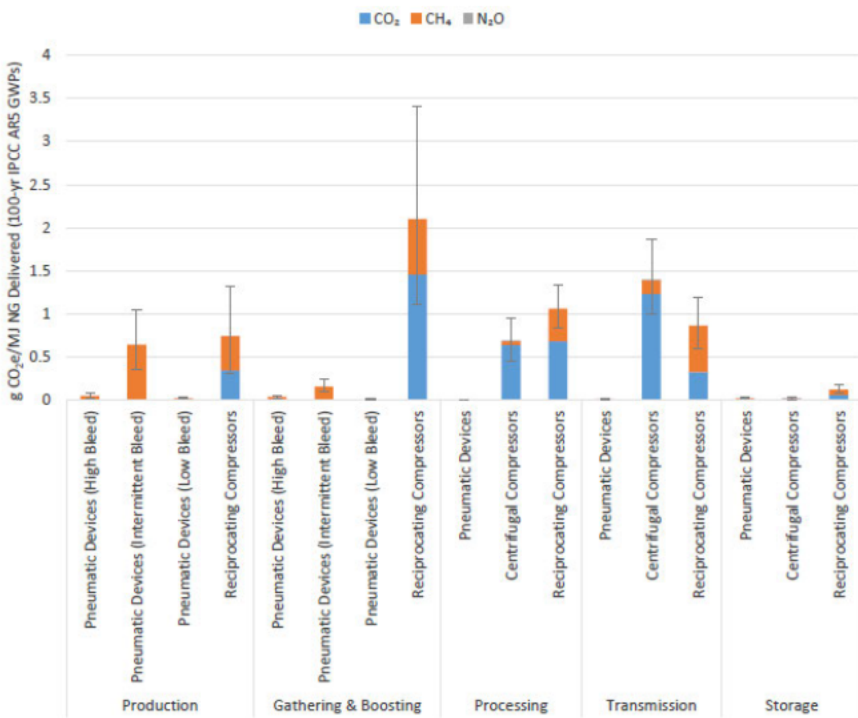


Commented [TS80]: State what year the data represents in the caption and what scope? US average for transmission and distribution combined?

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~~s~~), 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).

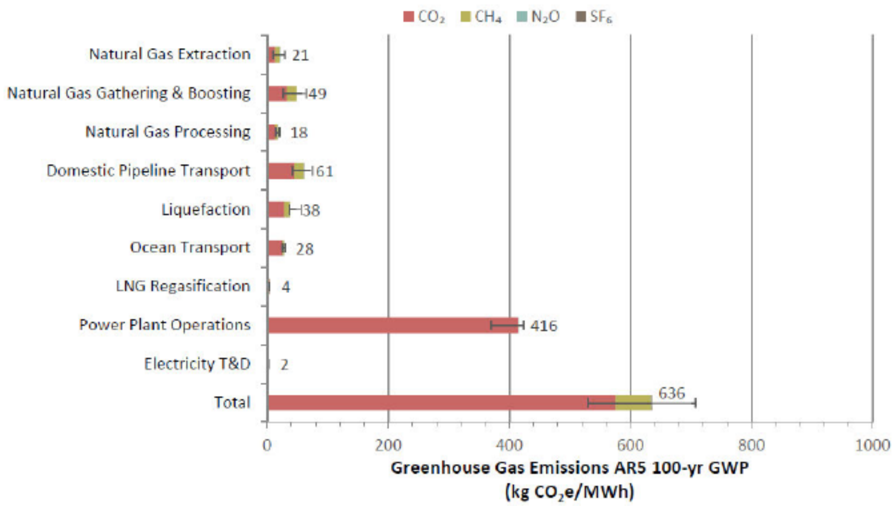
The NETL (2019) report that analyzed the lifecycle emissions of exporting U.S. LNG to Europe yielded the emissions results (assuming end-use in electricity generation) detailed in Exhibit 2-7.

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

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.

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

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.

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, thereby~~us, 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

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 reflected in the~~that~~ Rutherford et al. (2021) study estimate of the contribution from super-emitters (top 5 percent of emissions events). Given that the 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?

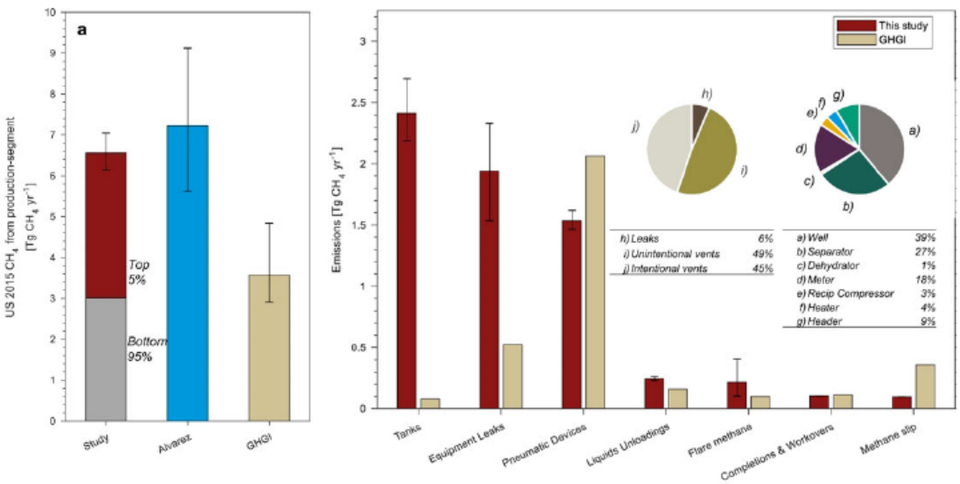
Commented [HSAJ95R94]: Revise sentence.

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

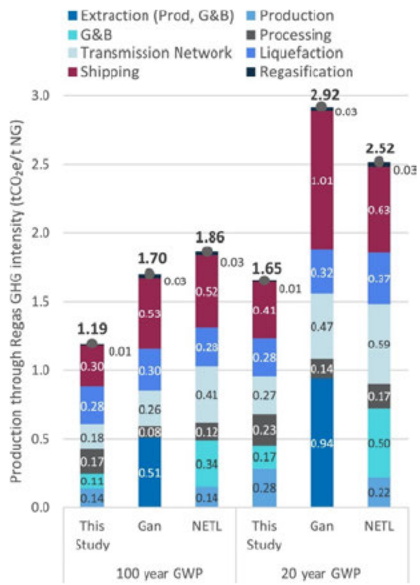
Commented [LBD98]: Comment applicable to other sections as well – is text being updated with more recent studies? (apologies if updating is ongoing in some sections and I'm not aware of it) Most or all of these studies (aside from NETL's) are >10 years old.

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~~. E -~~ each 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 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. ~~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 vehicle~~s~~ types from a wells-to-wheels perspective. In short, the Cai et al. (2017) study concluded ~~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 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~~s~~ 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~~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 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 rich~~lean~~ 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.

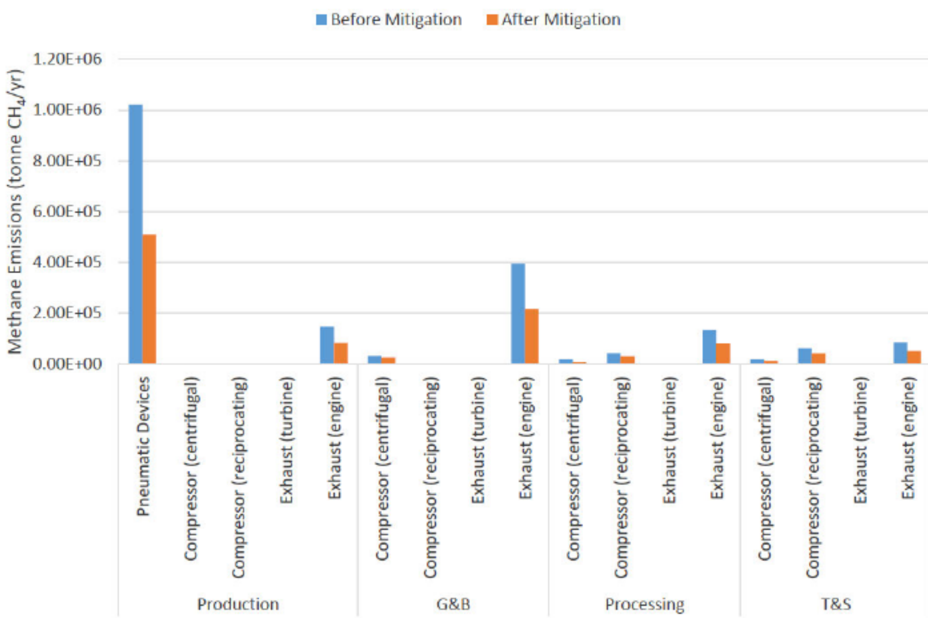
Commented [EK109]: NETL Team - with this proposed text correction, is the statement now accurate?

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 (CCS), CH_4 abatement, and efficiency upgrades contributing 43 percent, 12 percent, and 5 percent, respectively— and this suggested mitigation falls within national responsibilities, 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

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 (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):

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

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

- 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.

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

- 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 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 measurers needed to manage greater risks.

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

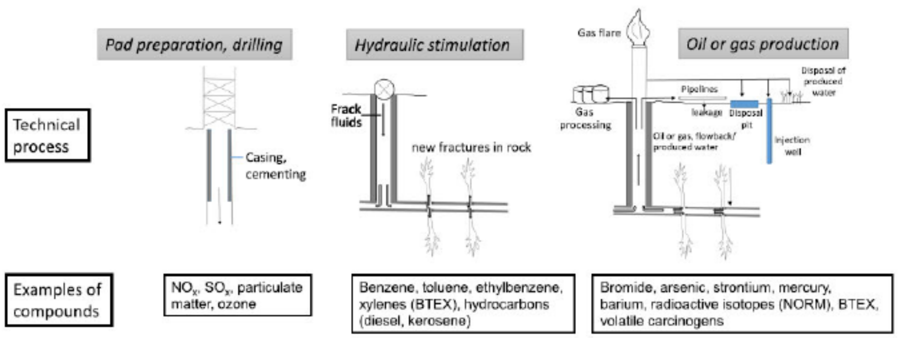
Commented [SW124R123]: I think that would be helpful.

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 (NAAQS) only places limits on six Criteria Air Pollutants including CO, ozone near the surface, NOx, PM, SO_2, and lead. Since the NAAQS~~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~~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~~~~Therefore, national regulations for the breadth of air emissions released during hydraulic fracturing are insufficient.~~ Exhibit 3-2 offers a perspective on non-GHG ~~a~~ir 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

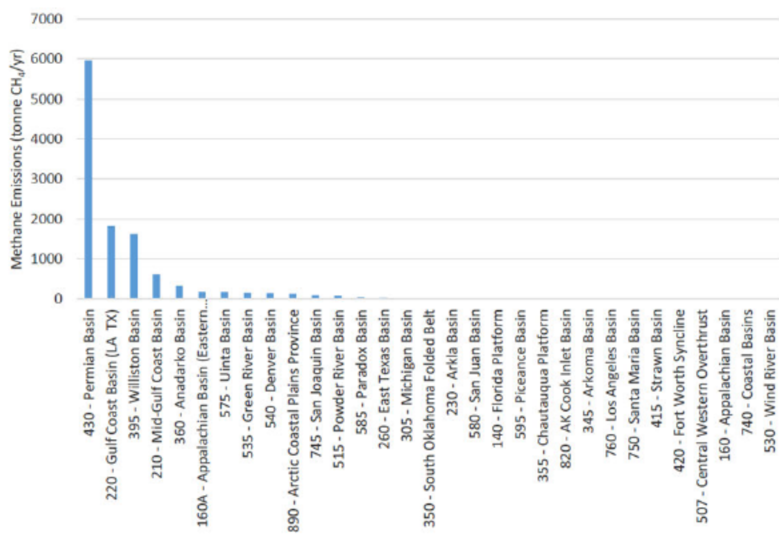
Permission pending from Wollin et al. (2020)

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 LNG~~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~~ 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.

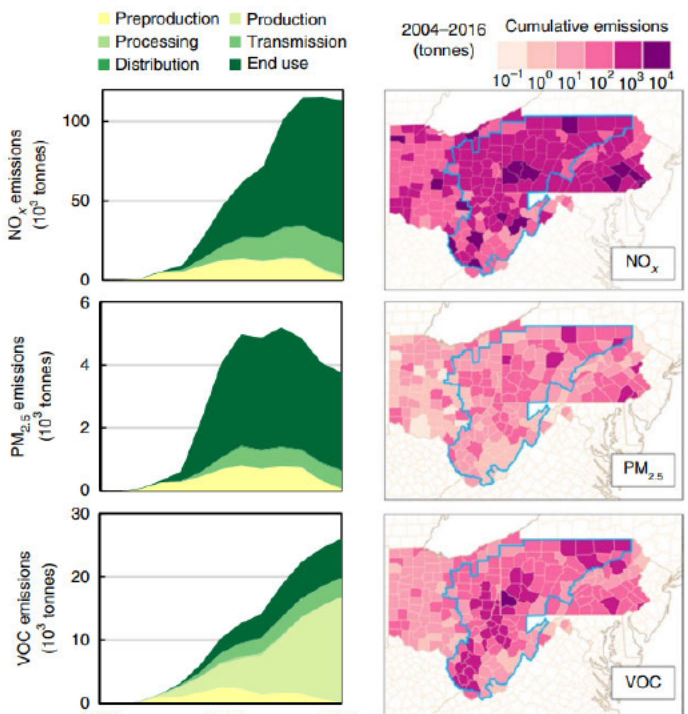
Commented [HSAJ134R131]: Open to making the point but chart should reflect. Reflect flaring is issue in some basins but not nation wide. Don't want to talk about outliers.

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).

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)

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.

3.4 References

Congressional Research Service (CRS). (2020). Methane and Other Air Pollution Issues in Natural Gas Systems. https://crsreports.congress.gov R42986

Elliott, E.G., Ettinger, A.S., Leaderer, B.P., et al. (2017) A systematic evaluation of chemicals in hydraulic-fracturing fluids and wastewater for reproductive and developmental toxicity. J Expo Sci Environ Epidemiol. ;27(1):90–99. doi: 10.1038/jes.2015.81

McMullin, T.S., Bamber, A.M., Bon, D., Vigil, D.I., Van Dyke, M. (2018) Exposures and Health Risks from Volatile Organic Compounds in Communities Located near Oil and Gas Exploration and Production Activities in Colorado (U.S.A.). Int. J. Environ. Res. Public Health. https://doi.org/10.3390/ijerph15071500

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

NETL. (2020). Opportunities for Natural Gas Supply Chain Efficiency. NETL. 56(22). 2020/2618

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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 20154 to ~~2014~~2015, 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?

Commented [RW140R139]: Done

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.

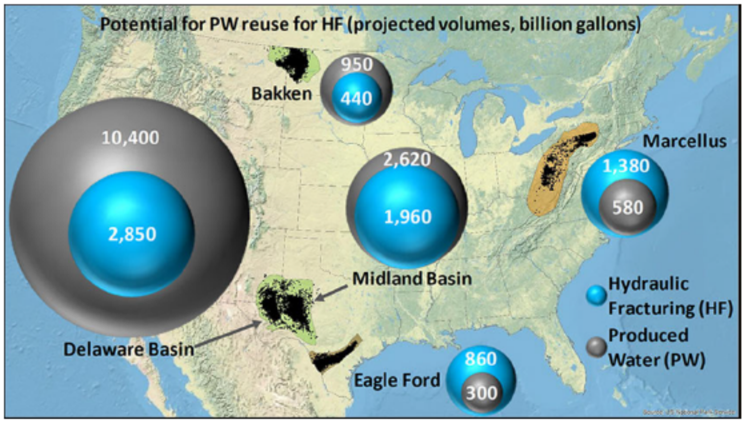
The shale boom has made energy more available and affordable globally, but has also contributed to environmental concerns surrounding the use of water. Scanlon et al. (2020) analyze the water-related sustainability of energy extraction. They focus on meeting the rapidly rising water demand for hydraulic 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 of water use 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 [LBD141]: Volumes of water use?

Commented [RW142R141]: changed

Water issues related to both fracking water demand and produced water supplies may be partially mitigated through the reuse of produced water to frack~~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 gigajoule~~s~~) 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 [HSAJ143]: 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 [HH144R143]: 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

Commented [EK145]: 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

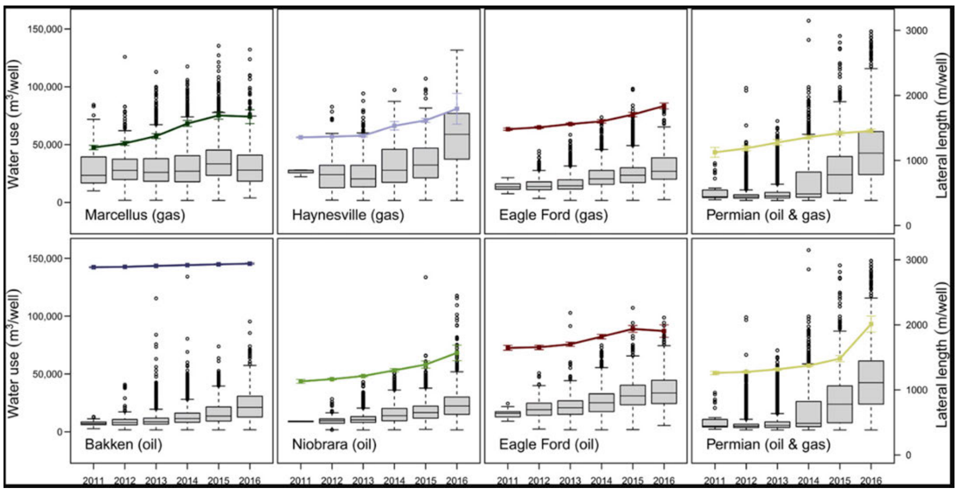
During 2009–2017, ~73,000 wells, or an aggregated total lateral length of ~440 × 10^6 ft (134,000 km), were drilled in the eight studied plays, equivalent to ~3× the Earth's circumference (40,000 km). Dieter et al. (2018) ~~find~~ found that to fracture the rock along that length, a total of ~480 B gal 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.

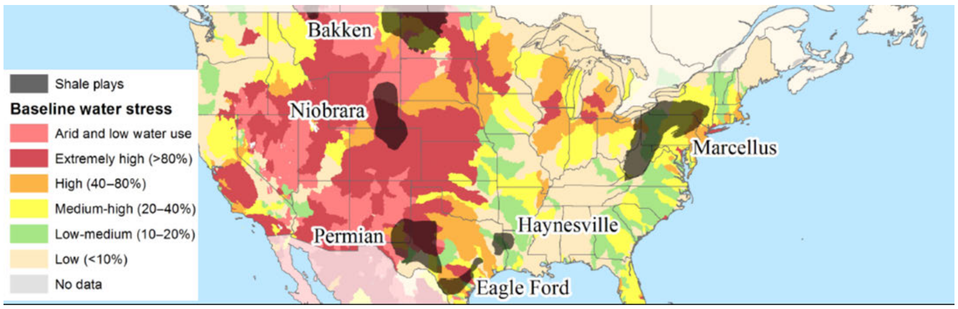
Exhibit 4-3. Water usage and lateral length by shale play



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 [RH146]: 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 [RW147R146]: Will rephrase, and thank you for the reference.

Commented [LBD148]: 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 [RW149R148]: understood

Commented [LBD150]: 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 [RW151R150]: Understood. Additionally, I have come across a new reference with respect to suspended solids and NORMs that I will be adding to this section.

Commented [EK152]: 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.

Commented [RW153R152]: Will do.

- 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 [HH154]: 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

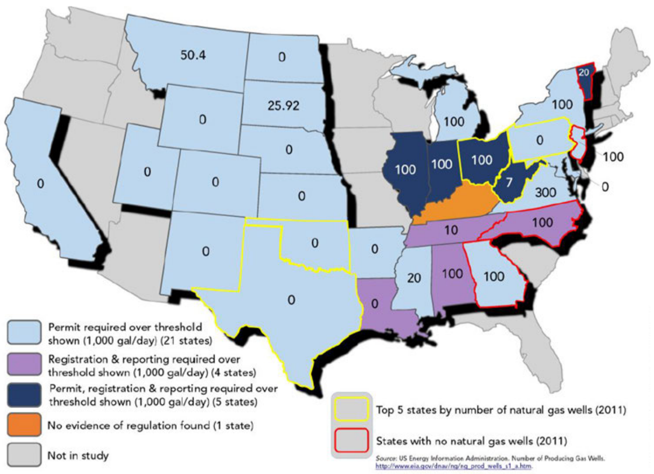
https://www.gwpc.org/wp-content/uploads/2023/06/2023-Produced-Water-Report-Update-FINAL-REPORT.pdf

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

Commented [TC155]: Please remove this section.

Commented [LBD156]: 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 ~~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.[k]

Commented [EK157]: 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.

[k] 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 [EK158]: 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 [EK159]: 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?

Commented [RW160R159]: Happy to remove.

- 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 six~~four~~ existing projects:

- Develop effective management and treatment technologies to treat produced water via energy- and cost-efficient approaches for use within the oil and gas industry (2 projects)
- Develop advanced optimization software, big data tools, and machine-learning platforms to automate time-intensive tasks and perform high-computational analysis on produced water and relevant produced water management infrastructure data (2 projects)
- Develop advanced or novel membrane specific technologies for treatment of produced water (1 project)
- Developing methods ~~to~~ for chemical and biological characterization of produced water ~~e~~ to~~and~~ 1) extract rare earth elements or critical minerals ~~from produced~~ and 2) identify safe, beneficial reuse applications for treated produced water ~~water~~ (2~~1~~ projects)

4.4 References

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Commented [EK161]: 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 [ST162R161]: NETL: we need to ensure consistency in the depth and breadth of R&D sections across the chapters. Lets discuss.

Commented [EK163]: HH: Our program pivoted from this some time ago and we are no longer pursuing research in this area.

Commented [EK164R163]: 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 [EK165R163]: HH: This does not include the 7-8 FOA awards which will be announced in the coming weeks - yes?

Commented [EK166R163]: @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 [HH167R163]: @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 [EK168R163]: OK, thanks for the clarification, Hichem. I'll bring this up tomorrow when I meet with @Sweeney, Amy and @Curry, Thomas.

Commented [HH169R163]: @Easley, Kevin Thanks, Kevin!

Commented [HH170]: 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 [LBD171]: Suggest update phrasing to more precise years as this reads as 2013-2023 to a current reader.

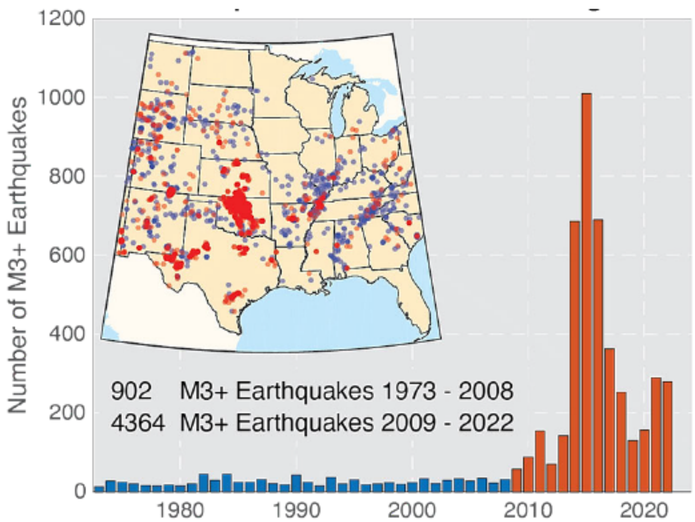
Commented [RW172R171]: Will do.

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

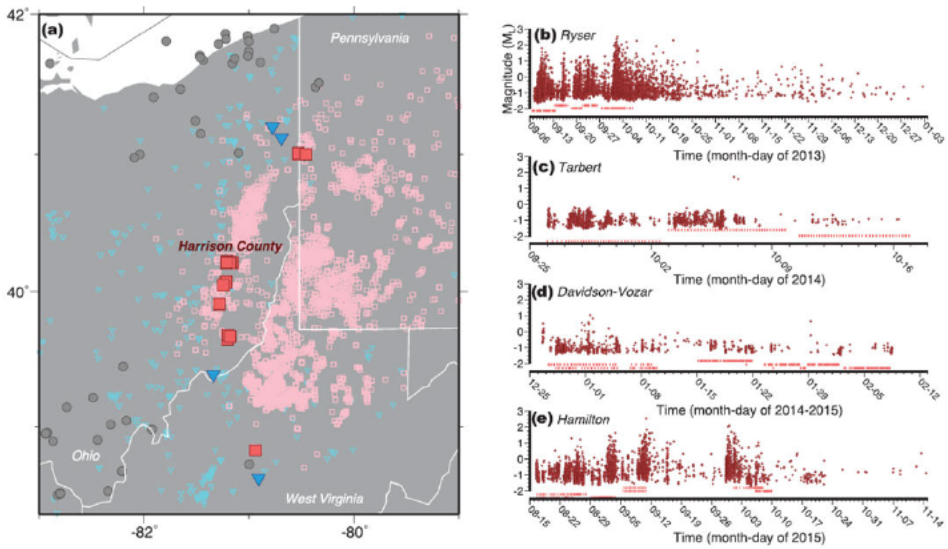
The Appalachian Basin is currently the largest natural gas producing area in the United States. The basin produced over 18 Mcf of natural gas a day (500 m^3/day) in 2019 (EIA, 2019a). The Marcellus and Point Pleasant Utica shale plays are both located in the Appalachian Basin and extend from New York 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 [EK173]: 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.

Commented [RW174R173]: I will double check.

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 ~~have~~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 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

[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.

Commented [EK175]: 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 [RW176R175]: Will check for consistency

Commented [EK177]: 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.

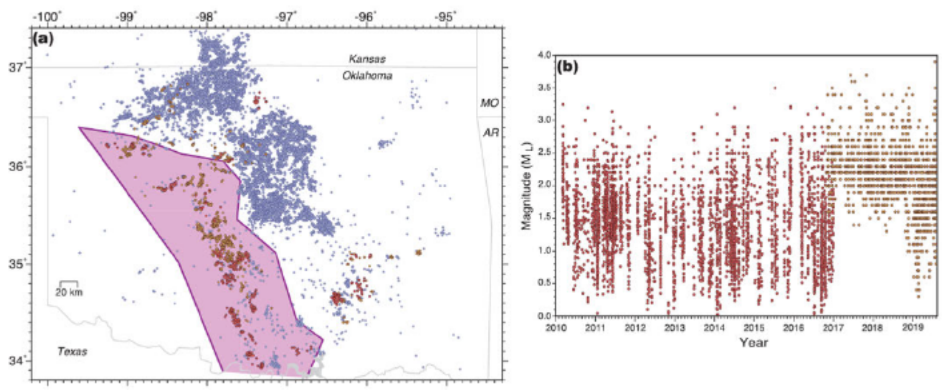
Commented [RW178R177]: It is incomplete. I believe there should have been a comma after the last word of the previous sentence.

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

Commented [EK179]: 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.

Commented [RW180R179]: Yes, corrected.

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~~ with 211 hydraulic fracturing well laterals.

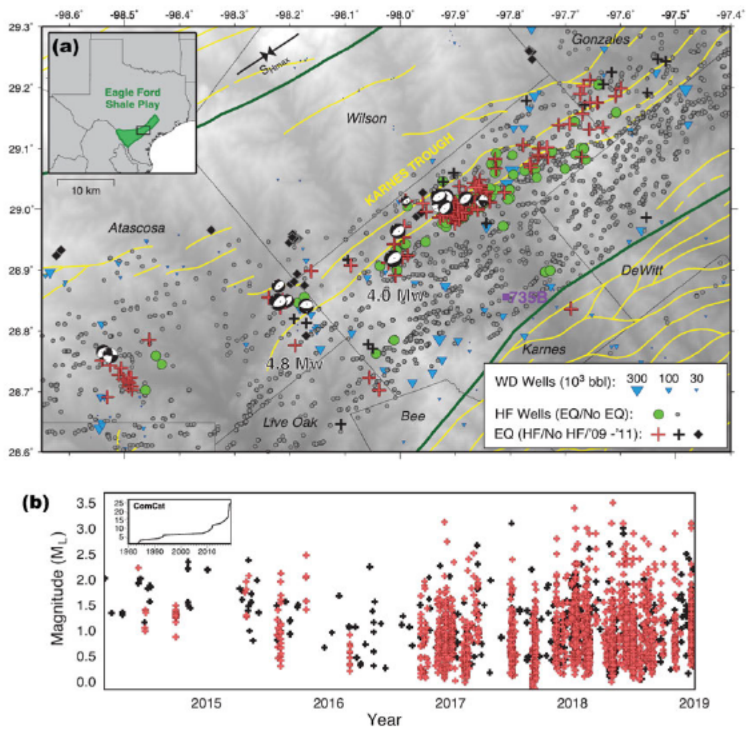
Commented [EK181]: NETL Team - 'will' (as written) or 'with' - or perhaps something else?

Commented [RW182R181]: with

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 events



Permission pending from Fasola et al. (2019)

5.2 Regulations to Address Induced Seismicity and Ong-~~G~~Going Research and Development

State regulators have long been focused on identifying the precise location and magnitude of earthquakes and determining their cause. When~~If~~ earthquakes can be linked to wastewater injection, regulators respond~~could~~ by ordering~~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 created the~~s~~ Coordinating Council on Seismicity (2014)

Commented [EK183]: NETL Team - Changed 'If' to 'When' since the Addendum has already cited wastewater injection is one driver of induced seismicity.

Commented [RW184R183]: ok

- Oklahoma Corporation Commission directives reduce injection (2015)
- Oklahoma Geological Survey position paper published (2015)
- Secretary of Energy funded ~~as~~ $200,000 worth of 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 ~~t~~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 Teas 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 [EK185]: NETL Team - to your knowledge, is this 2015 funding reference the most recent DOE / S-1 investment into induced seismicity projects?

Commented [LBD186]: Is any update available?

Commented [EK187]: NETL Team - it's unclear who the 'Applicants' are, what they are applying to, etc. Please provide additional details.

Commented [EK188R187]: Are we referring to operators in Texas applying for permits of one type or another RE: drilling, disposal, etc.? Please clarify.

Commented [LBD189]: 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 ~~of~~ 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 new~~d~~ or modify existing operations
- ML ≥ 2.5 – Temporary halt of well completions on lateral
- ML = 3.0+ – Well ~~C~~completion on pad suspended until an operator produces and secures approval of plan to mitigate risks and return to operational status~~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 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 [EK190]: 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 [EK191]: 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 [EK192]: 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 [EK193]: 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.

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 [HSAJ194]: 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.

Commented [EK195R194]: 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.

Commented [EK196]: 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.

Commented [RW197R196]: ok

transportation via transmission pipelines (transmission stage), and gas consumption as fuel~~the use~~ through combustion in gas-fired power plants (use stage).

Commented [EK198]: NETL Team - 'the use through' was somewhat clunky so I switeched up the text.

Commented [RW199R198]: ok

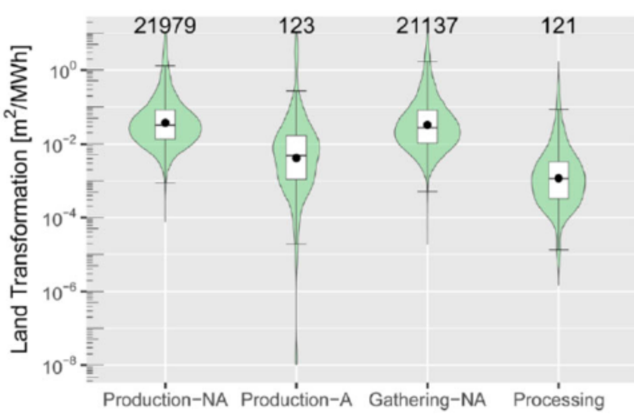
For the production stage, Dai et al. (2023) mapped land-use for 100,009 wells located at 75,915 different well pads. Among the 100,009 wells examined, 31,716 were co-located. In non-agricultural areas, results suggest vertical wells occupy ~4000 square meters (m^2) less land per site than horizontal-/directional-drilled 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 consumption~~use~~ of natural gas (Dai et al., 2023).

Commented [LBD200]: Suggest a few words explaining how, or possibly delete this sentence.

Commented [RW201R200]: I will look to expand the text from the source. If I cannot find specific examples, I will delete the 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

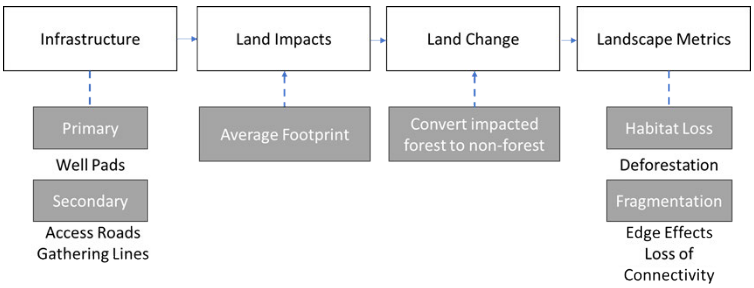
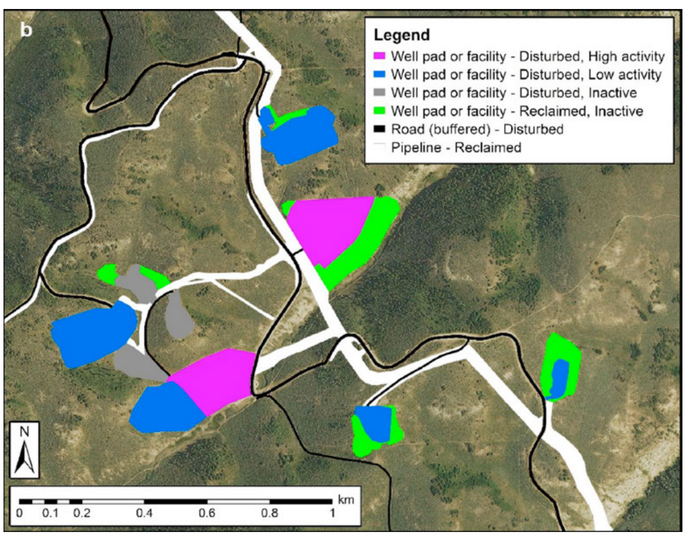


Exhibit 6-4 provides an example of energy infrastructure features digitized from 2013 National Agricultural Inventory Program satellite imagery overlaid with well locations reported in COGCC data. Each mapped feature (or portion thereof) was classified by type (well pad, facility, road, or pipeline) 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 (OECD) countries (Hafner et al., 2017; Boslett, 2021).

Commented [EK202]: Please add OECD to the Acronyms List.

Commented [RW203R202]: Will do

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).

Commented [LBD204]: This section should be alongside material in the first para of this section that addresses some human health effects.

Commented [RW205R204]: Will move it. Thank you!

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

Commented [LBD206]: Is "pollution" the right term? Air pollution from traffic is addressed above, so perhaps just "traffic"?

Commented [RW207R206]: ok

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 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 (ESA) 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.

Commented [EK208]: 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.

Commented [EK209]: Please add ESA to the Acronym List.

Commented [RW210R209]: ok

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~~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~~research and development~~ or analysis with respect to land use, habitat fragmentation, or light, noise, or traffic pollution being conducted by DOE.

Commented [HSAJ211]: Comment for FE/HQ - Please advise if this is incorrect. We made every attempt to find information on current and ongoing R&D.

Commented [ST212R211]: If you are not sure it is accurate, we should not say it.

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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 perpetuat~~e~~ing instances of energy, environmental, and social injustice. Conversely, if potential impacts to disadvantaged and frontline communities[o] 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 [LBD214]: 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.

o 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 [RK215]: 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 [RK216R215]: If these recommendations are included then a title "Societal Considerations, Impacts, and Justice in UNG and LNG infrastructure development"

Commented [BO217R215]: 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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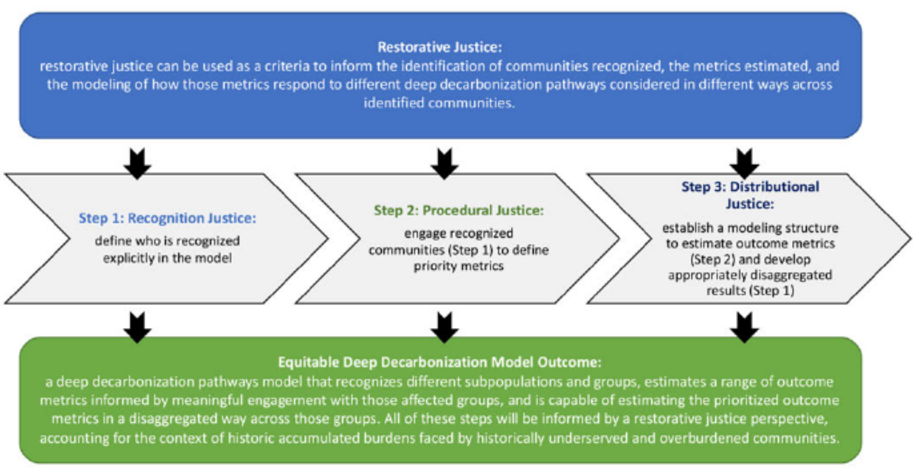
7.2 Distributional, Procedural, and Recognition Justice

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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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).

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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[p] necessarily highlights how these costs are going to be born geospatially.

[p] 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

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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[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: Francisco De La Chesnaye
Sent: Fri, 27 Oct 2023 00:01:22 +0000
To: Curry, Thomas; Skone, Timothy; Sweeney, Amy
Cc: Yarlagadda, Brinda; Harker-Steele, Amanda J (NETL); Robert Wallace; Agboola, Ajoke; Jamieson, Matthew B (NETL); Wallace, Robert T (NETL); Scott Matthews; Matthews, Howard S (NETL); Iyer, Gokul; Edmonds, James A (Jae); Binsted, Matthew; Wolfram, Paul; Whitman, Peter C; Daniel Hatchell; Riera, Jefferson
Subject: [EXTERNAL] FECM LNG Export Project Coordination
Attachments: DOE_FECM_LNG_Analysis_Report_26Oct23.docx

DRAFT/DELIBERATIVE/PRE-DECISIONAL

Dear FECM Team,

Please find attached the latest draft version of the report "ENERGY, ECONOMIC, AND ENVIRONMENTAL ASSESSMENT OF U.S. LNG EXPORTS". This version has been through another round of technical editing to address most of the comments received in the previous version. There also are additional results tables in the appendix, mainly on the LCA results. Thanks to all they staff who have worked on the latest update.

For tomorrow's project meeting, I propose the following agenda:

1. Update on review process from FECM
2. Review and Update on FECM Memo "Key Modeling Questions"
   - GCAM technology sensitivity cases
   - NEMS Macroeconomic modeling
   - Other question(s)

Let me know if any other analysis or report items should be covered.

Best, Paco

Francisco De La Chesnaye | **Vice President**
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OFFICE OF RESOURCE SUSTAINABILITY

ENERGY, ECONOMIC, AND ENVIRONMENTAL ASSESSMENT OF U.S. LNG EXPORTS

DRAFT/DELIBERATIVE/PRE-DECISIONAL

October 26, 2023 Draft

ENERGY, ECONOMIC, AND ENVIRONMENTAL ASSESSMENT OF U.S. LNG EXPORTS

FINAL REVIEW DRAFT September 5, 2023

Prepared for:

U.S. Department of Energy, Office of Fossil Energy and Carbon Management,
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ACRONYMS AND ABBREVIATIONS

°C	Degrees Celsius
AEO	Annual Energy Outlook
AgLanduse	Agricultural land use
AR5	Fifth Assessment Report
AR6	Sixth Assessment Report
AR6-100	Sixth Assessment Report, 100-year basis
Bcf, BCF	Billion cubic feet
Bcf/d	Billion cubic feet per day
BECCS	Bioenergy with carbon capture and storage
BIL	Bipartisan Infrastructure Law
BP	British Petroleum
Btu	British thermal unit
C_2F_6	Hexafluoroethane
C Asia + East Eur	Central Asia and Eastern Europe
ccf	Climate–carbon cycle Feedback
CCS	Carbon capture and storage
CCUS	Carbon capture, utilization, and storage
CDR	Carbon dioxide removal
CF_4	Tetrafluoromethane
CH_4	Methane
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
DAC	Direct air capture
DACCS	Direct air carbon capture and storage
DOE	Department of Energy
EIA	Energy Information Administration
EJ	Exajoule (10^{18} joules)
EPA	Environmental Protection Agency
EU	European Union
F-gases	Fluorinated gases
FECM	Office of Fossil Energy and Carbon Management
g	Gram
GCAM	Global Change Analysis Model
GDP	Gross domestic product
GHG	Greenhouse gas
GoM, GOM	Gulf of Mexico
Gt	Gigaton
GWP	Global warming potential
H_2	Hydrogen
HFC…	Hydrofluorocarbons
HHV	Higher heating value
HMM	Hydrogen Market Module
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
IRA	Inflation Reduction Act
ITC	Investment tax credit
LAC	Latin American countries
LCA	Life cycle analysis
LHV	Lower heating value
LNG	Liquefied natural gas
LUC	Land use change
LULUCF	Land use, land use change, and forestry
MAF	Market adjustment factor
MAM	Macroeconomic Activity Module
Mcf	Million cubic feet
MJ	Megajoule
MMBtu	Million British thermal units
N_2O	Nitrous oxide
NA	Not available/applicable
NEMS	National Energy Modeling System
NERA	NERA Economic Consulting
NETL	National Energy Technology Laboratory
NG	Natural gas

Commented [PW1]: Deleted CAFE, as per AA

Commented [PW2]: Deleted CAFE, as per AA

NGA	Natural Gas Act
NGP	Natural gas processing
NZ	New Zealand
O&M	Operating and Maintenance
OGSM	Oil and Gas Supply Module
PNNL	Pacific Northwest National Laboratory
PTC	Production tax credit
ROW	Rest of the World
RRC	Railroad Commission
S1	Scenario 1
S2	Scenario 2
S3	Scenario 3
S4	Scenario 4
S5	Scenario 5
S6	Scenario 6
S7	Scenario 7
SF_6	Sulfur hexafluoride
Tcf, TCF	Trillion cubic feet
Tg	Teragram (10^{12} grams)
U.S., USA	United States
yr	Year

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EXECUTIVE SUMMARY

The Department of Energy (DOE) is responsible for authorizing exports of United States (U.S.) natural gas, including liquefied natural gas (LNG), to foreign countries pursuant to Section 3 of the Natural Gas Act (NGA), 15 U.S.C. 717b. DOE is required to grant a permit to export domestically produced natural gas unless it finds that such action is not consistent with the public interest.

To inform its public interest determination, since 2012, DOE's Office of Fossil Energy and Carbon Management (FECM) and its predecessor, the Office of Fossil Energy, has commissioned five studies to assess the effects of different levels of LNG exports on the U.S. economy and energy markets. This sixth updated study, like the previous ones, will serves as an input to be considered in the evaluation of applications to export LNG from the United States under Section 3 of the NGA.

The purpose of this latest study is to examine the potential global and U.S. energy system and greenhouse gas (GHG) emissions implications of a wide range of economic levels of U.S. LNG exports. The study comprises three coordinated analyses: 1) a **Global Analysis** to explore a wide range of scenarios of U.S. LNG exports under alternative assumptions about future population and economic growth, regional preferences for domestically produced natural gas, pace of technological change in competing technologies (e.g. renewables), and countries' announced GHG emissions pledges and policies; 2) a **U.S. Domestic Analysis** of the implications of the various U.S. LNG export levels derived from the Global Analysis for the supply and demand of natural gas within the United States and the U.S. economy; and 3) a **Life Cycle Analysis** (LCA) to examine the life cycle emissions implications of the various levels of U.S. LNG exports derived from the Domestic Analysis and Global Analysis.

As part of the Global Analysis, DOE-FECM explored seven scenarios spanning a range of plausible U.S. LNG export outcomes by 2050 using the Pacific Northwest National Laboratory's Global Change Analysis Model (GCAM). GCAM is a model of global energy, economy, agriculture, land use, water, and climate systems with regional detail in 32 geopolitical regions. This includes major economies as single-country regions (e.g., United States, Canada, China, India, Russia). The seven scenarios explored in this study are shown in Table ES-1.

Table ES-1. Scenario descriptions

Scenario	Description	U.S. LNG Export Volumes (Bcf/d)
***S1*: Reference Exports**	U.S. LNG exports follow AEO2023. Incorporates U.S. policy assumptions (including the 2022 Inflation Reduction Act). Assumes existing policies and measures, globally.	Grows to 27.3 Bcf/d by 2050
***S2*: Market Response**	Assumes policies consistent with *S1*, but U.S. LNG exports are determined by global market equilibrium.	GCAM Market Response
***S3*: High Global Demand**	Same assumptions as *S2*, U.S. LNG exports determined by global market equilibrium, but assumes higher population growth outside of the U.S.	GCAM Market Response
***S4*: Regional Import Limits**	Same assumptions as *S2*, U.S. LNG exports determined by global market equilibrium, but includes constraints on importing and exporting natural gas with a global focus to maximize use of domestic gas.	GCAM Market Response

Commented [TC4]: Let's add a paragraph on general limitations on modeling, consistent with the discussion at and following the leadership briefing. The Exec Summary should have a summary of caveats and the introduction should have a broader discussion.

Commented [TC3]: Global comments:
-The report needs an edit to improve consistency of voice.
-Make sure there is consistency in units. Consistent report units. GCAM uses EJ and NEMS is quads (quadrillion Btu). 1 quad = 1.-5506 EJ
a.There is a mix in the report currently.
i.Primary Energy: quads and EJ
ii.Gas production/Exports/Imports: Tcf and Bcf/day
iii.GHG emissions: Gigatonnes (metric tons), MMT (million metric tons)
iv.LCA/GHG: grams per megajoule
b.Recommend energy and mass be in metric units and volume (of gaseous natural gas) be reported in English units of cubic feet (industry standard convention).
-Move away from qualitative descriptions like "modest" or "small" and toward quantitative information with context for the reader to make a qualitative assessment.
-Include detailed data that can be used by the reader to understand figures in new appendices.
-In general, the report would benefit from more discussion of why the trends or results we are seeing are consistent with expectations. For example, making

Commented [HH5]: Unnecessarily in the weeds for an Ex Sum.

Commented [LBD6]: I'm not familiar with "growth" as a noun modified by this word... if this is meant to mean both population growth and economic growth, suggest saying both. Or maybe it's just "economic growth"?

Commented [IGC7R6]: It refers to population and economic growth.

Commented [HH8]: NETL wants "United States" spelled out when used as a noun; "U.S." is fine when used as an adjective. I've made the appropriate changes throughout the report.

Commented [UP9]: Do we have to show by 2 digits in 2050? EIA's TIE article for example rounds to just 1-digit showing 27.3 Bcf/d which prob is better. https://www.eia.gov/todayinenergy/detail.php?id=56600

Commented [PW10R9]: Revised, thank you.

Scenario	Description	U.S. LNG Export Volumes (Bcf/d)
***S5*: Low-cost Renewables**	Same assumptions as *S2*, U.S. LNG exports determined by ~~global market equilibrium, but assumes lower capital costs for~~ renewable energy technologies.	GCAM Market Response
***S6*: Energy Transition (Ref Exp)**	Assumes an emissions pathway consistent with a global temperature change of 1.5°C by end of century. Countries' emissions are constrained to announced GHG pledges, including the U.S. following a path to net-zero GHG emissions by 2050. NEMS follows CO_2 emissions constraint from GCAM. U.S. LNG exports are limited to the values from *S1*.	Grows to 27.3 Bcf/d by 2050
***S7*: Energy Transition**	Same emissions pathway assumptions as *S6*, but U.S. LNG exports are determined by global market equilibrium.	GCAM Market Response

All of the scenarios include representations of the 2022 Inflation Reduction Act (IRA) in the United States and existing emission policies in the rest of the world. The scenarios also include a constraint on Russian exports. The modeling and analysis for this report were completed by August 2023.

The **U.S. Domestic Analysis** was conducted using the National Energy Modeling System (NEMS). U.S. LNG exports (for all scenarios except *S1*) and carbon dioxide (CO_2) emissions (in scenarios *S6* and *S7*) used in NEMS were harmonized to values from GCAM. NEMS was then used to explore the implications of the seven global scenarios on domestic gas prices, the energy system, and the macro-economy within the United States.

The **LCA** of natural gas used for export was enhanced by comparing the results from the domestic and global analyses to previously completed National Energy Technology Laboratory (NETL) studies of the natural gas life cycle. GCAM results were assessed against existing DOE life cycle studies of natural gas and aligned to have the same GHG intensity for the purposes of consistency. The main results of this analysis were a series of estimated market adjustment factors that supplement the previous LCAs and better represent the total global change in emissions per unit of U.S. LNG exported.

A number of key insights emerged from this study:

1. Across all modeled scenarios, U.S. LNG exports and U.S. natural gas production increase beyond current levels through 2050 (Figure ES-1). In these scenarios, U.S. LNG exports range 23–49 billion cubic feet (Bcf)/day. The range of U.S. LNG exports from this study is consistent with the U.S. Energy Information Administration's (EIA) analysis (15–48 Bcf/day).[1]
2. Global natural gas consumption increases by less than 1% under a scenario with increased availability of U.S. natural gas in the global market that reflects economically driven LNG export levels (*Scenario 2 [S2]*) compared to the reference scenario (*Scenario 1 [S1]*). Most of the additional U.S. natural gas substitutes for other global sources of natural gas.
3. By 2050, U.S. natural gas prices as measured at the Henry Hub increase when comparing *S2* to *S1*. Across those scenarios, 2050 Henry Hub prices are projected to increase from $3.88/million cubic feet (Mcf) to $5.09/Mcf ($2022), both of which are less than the reference 2050 price

[1] U.S. EIA. (2023). Issues in Focus: Effects of Liquefied Natural Gas Exports on the U.S. Natural Gas. Available at: Markethttps://www.eia.gov/outlooks/aeo/IIF_LNG/

Commented [HH11]: Cost should be capitalized in this scenario title throughout the report. However, it occurs uncapitalized in many un-editable figures. To maintain consistency, I've left this as is.

Commented [UP12]: S6 has a different background color than the other sections of the table? Also on the third column why is GCAM Market Response "white background" for S2-S5 but then "blue" for S7?

Commented [UP13]: Should "economically driven" have a hyphen or not? We seem to sometimes hyphenate it and sometimes not. I added hyphens but can be reversed.

Commented [IGC14R13]: I am OK with economically-driven, with the hyphen.

Commented [HH15R13]: This should not be hyphenated. "Very" and any adverb ending in "ly" should not be hyphenated when part of a compound modifier (as we have here). I've adjusted accordingly throughout the text.

Commented [ZA16]: Is a 30% price increase modest?

Commented [LBD17]: Hard to describe as a "modest" increase, if in constant dollars. The increase is almost 1/3.

Commented [PW18R17]: Removed.

Commented [LBD19]: Suggest specify real or current dollars

Commented [PW20R19]: Added constant dollrs expected in the most recent study commissioned on the economic impacts from U.S. LNG exports in 2018. While LNG export profiles were different, natural gas prices in *S2* were comparable to EIA's "Fast Builds Plus High LNG Price"[1] scenario ($4.98/Mcf).

4. U.S. residential prices are projected to be 4% higher in 2050 when comparing *S2* to *S1*. The change in residential prices did not exceed 4% in any of the scenarios and the percentage difference was generally substantially less.
5. The value of industrial shipments remains essentially unchanged (increasing less than 0.1% by 2050) under *S2* compared to *S1*. The impact of increased LNG exports on global domestic product is essentially flat: positive by less than 0.1% across scenarios through 2045 while all changes are within 0.3% in 2050.
6. Global and U.S. GHG emissions do not change appreciably across the scenarios with current climate policy assumptions (*Scenario 2 [S2]–Scenario 5 [S5]*) even though these scenarios vary widely in terms of U.S. LNG export outcomes. In these scenarios, global net GHG emissions range 47.5–50.3 gigaton (Gt) CO_2 equivalent (CO_2e) and U.S. emissions range 4.3–4.6 Gt CO_2e.
7. The induced global market effects per unit of increased U.S. LNG exports in *S2* compared to *S1* are equivalent to an overall reduction in GHG emissions that is about 70% of the estimated upstream emissions associated with production through delivery of the natural gas through the transmission system in the United States.
8. Relative to the other scenarios (*S1–S5*), the scenarios in which countries are assumed to achieve GHG emissions pledges and pursue ambitious GHG mitigation policies (*Scenario 6 [S6]* and *Scenario 7 [S7]*) are characterized by lower energy consumption; lower fossil fuel consumption without carbon capture, utilization, and storage (CCUS); higher deployment of renewables and fossil fuels and biomass with CCUS; and higher deployment of CO_2 removal strategies.

Commented [AA21]: Just FYI for tech writer: Previous references were not italicized.

Commented [WS22]: There is a notable difference in the way we present the data from our conclusions. When we reference GDP, gas consumption, and prices, we scale the effect against the global or national total, resulting in small percentage changes. When we talk about GHGs we scale the effect to units of gas exported. But the table in the appendix shows that the reduction in emissions between S2 and S1 is 50 million tons – or roughly 0.01% of global emissions. I recommend that we take a more consistent approach to characterizing the model results.

Commented [PW23R22]: This result is relevant to extending the LCA analysis, and results from a distinct methodolg.. LCA are always expressed per unit.

Suggest adding In order to enhance the LCA analysis of LNG exports.

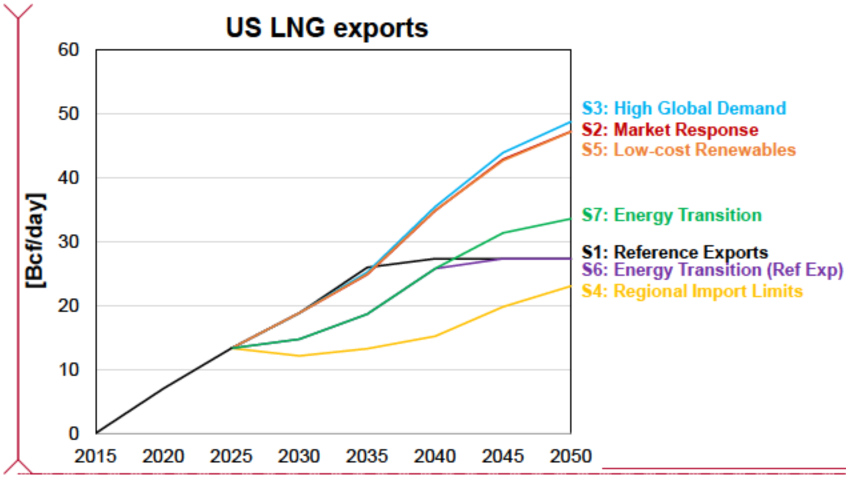
Commented [WS24]: This sentence has way too many elements and needs to be re-written.

Commented [LBD25]: It's not completely clear to me why this comparison is made – it seems like there is a projected reduction in GHG emissions from S1 to S2, but it's small? A global reduction equal to 70% of the LC emissions of one large industrial user? If that's correct, it might be clearer to just present the percentage reduction, or say that it was essentially the same level of emissions.

Commented [ST26]: Did we run a non-CCUS S6 and S7 case?

What supports this finding?

Commented [IGC27R26]: All of our scenarios include both fossil fuel technologies w/ and w/o CCUS. The point of this statement is to compare S6 and S7 that have climate policy with other scenarios S1-S5 without climate policy. Compared to the scenarios ***without*** climate policy (S1-S5), the scenarios ***with*** climate policy (S6-S7) have lower fossil w/o CCUS.



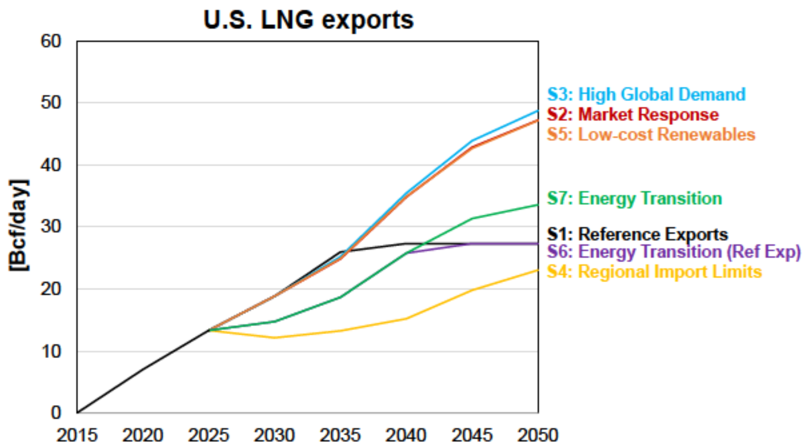


Figure ES-1. U.S. LNG exports across the scenarios explored in this study. Note that the U.S. LNG export outcomes for S2 and S5 were very close to each other.

Several considerations are required in interpreting this study and its results. Foremost, this study is not intended to serve as a forecast of U.S. LNG exports. Rather, it is an exercise in exploring alternative conditional "what-if" scenarios of future U.S. LNG exports and examining their implications for the global and U.S. energy and economic systems, and GHG emissions. Such scenario analysis is a well-established analytical approach for exploring complex relationships across a range of variables. In addition, the scenarios explored in this study are meant to span a range of plausible U.S. LNG export outcomes by 2050. However, they hinge on many assumptions about a wide range of domestic, international, economic, and non-economic factors such as future socioeconomic development, technology and resource availability, technological advancement, institutional change, and more. A full uncertainty analysis encompassing all of the above factors was beyond the scope of this study. This

Commented [HH28]: US should be U.S.

Commented [IGC29]: I've copied this paragraph here – including an expanded discussion – from the Introduction. May need to rephrase some of the sentences here or simply delete this paragraph from the Intro section.

Commented [IGC30R29]: Update: I think we decided to keep in both places.

study does not attach probabilities to any of the scenarios and no inference about the likelihood of these scenarios occurring should be made. Finally, although the scenarios explored in this study model the actual provisions in the IRA in the United States, *S6* and *S7* that incorporate countries' climate pledges do not explicitly model the actual policy instruments, sectoral measures, and regulations that countries might adopt to meet those pledges due to lack of sufficient literature on policy instruments, regulations, and mechanisms over the longer time horizon of focus in this study. Instead, these scenarios assume that countries achieve their pledges within their geographic boundaries through a cost-effective combination of sectoral transitions. The results from these scenarios described in this report could be different depending on the actual policies and mechanisms that countries use to meet their stated pledges.

INTRODUCTION

A. Study Background

The Department of Energy (DOE) is responsible for authorizing exports of natural gas, including liquefied natural gas (LNG), to foreign countries pursuant to Section 3 of the Natural Gas Act (NGA), 15 U.S.C. 717b. Under the NGA, applications requesting authority for the import or export of natural gas, including LNG, from and to a nation with which there is, in effect, a free trade agreement requiring national treatment for trade in natural gas, and/or the import of LNG from other international sources, are deemed consistent with the public interest and granted without modification or delay. For authorizations relating to those countries with which the United States (U.S.) does not have such a free trade agreement, and with which trade is not prohibited by U.S. law or policy, Section 3(a) of the NGA requires DOE to grant a permit to export domestically produced natural gas unless it finds that such action is not consistent with the public interest.[2]

DOE identified a range of factors that it evaluates when reviewing an application for LNG export authorization. Specifically, DOE's review of export applications focuses on "1) the domestic need for the natural gas proposed to be exported, 2) whether the proposed exports pose a threat to the security of domestic natural gas supplies, 3) whether the arrangement is consistent with DOE's policy of promoting market competition, and 4) any other factors bearing on the public interest as determined by DOE, such as international and environmental impacts."[3]

To inform its public interest determination, since 2012, DOE's Office of Fossil Energy and Carbon Management (FECM) and its predecessor, the Office of Fossil Energy, has commissioned five studies on the effects of increased LNG exports on the U.S. economy and energy markets. The previous studies of the impact of LNG exports are listed in **Error! Reference source not found.**.

Table 1. Previous studies

Report Name	Organization	Short Name
Effect of Increased Natural Gas Exports on Domestic Energy Markets[4]	EIA	EIA 2012
Effect of Increased Natural Gas Exports on Domestic Energy Markets[5]	NERA	NERA 2012
Effect of Increased Levels of Liquefied Natural Gas Exports on U.S. Energy Market[6]	EIA	EIA 2014

Commented [AA31]: Perhaps I missed it, but it would be nice to have a section on "limitations" or a disclaimer or a brief description of what this study did not/cannot do.

Commented [PW32R31]: Paragraph on limitations now last paragraph of Purpose of Study

Commented [HH33]: Changed this main section to a subsection under the introduction.

Commented [ZA34]: Same

Commented [PW35R34]: See above

Commented [UP36]: Table 1 should be moved back to below paragraph 1 where it is mentioned.

Commented [PW37R36]: Done

[2] Natural Gas Act. 15 U.S.C. 717b.

[3] Order Amending Long-Term Authorization to Export Liquefied Natural Gas to Non-Free Trade Agreement Nations at 43, Magnolia LLC, Docket 13-132-LNG (April 2022).

[4] U.S. EIA. (2012). Effects of Increased Natural Gas Exports on Domestic Energy Markets. Available at: https://energy.gov/sites/prod/files/2013/04/f0/fe_eia_lng.pdf

[5] NERA Economic Consulting. (2012). Macroeconomic Impacts of LNG Exports from the United States. Available at: https://energy.gov/sites/prod/files/2013/04/f0/nera_lng_report.pdf

[6] U.S. EIA. (2014). Effect of Increased Levels of Liquefied Natural Gas Exports on U.S. Energy Markets. Available at: https://www.eia.gov/analysis/requests/fe/pdf/lng.pdf

Report Name	Organization	Short Name
The Macroeconomic Impact of Increasing U.S. LNG Exports[7]	Baker Institute/ Oxford Economics	Baker 2018
Macroeconomic Outcomes of Market Determined Levels of U.S. LNG Exports[8]	NERA	NERA 2018

The Energy Information Administration (EIA) 2012 study examined four different levels of exports across four domestic natural gas supply scenarios for a total of 16 scenarios. Exports ranged 6–12 billion cubic feet (Bcf)/day with varying trajectories. The supply scenarios were Annual Energy Outlook (AEO)2011 Reference, High Shale Estimated Ultimate Recovery, Low Shale Estimated Ultimate Recovery, and High Economic Growth. Key results demonstrate that domestic natural gas markets balanced the increased exports through increased supply and prices and a reduction in demand for power generation and in the other sectors.

The NERA Economic Consulting (NERA) 2012 report used NERA's Global Natural Gas Model and NewERA energy-economy model to look at the domestic economic effects of LNG exports. Building upon the EIA 2012 study, the NERA 2012 report examined 16 scenarios from the earlier study using different assumptions on natural gas supply and demand. The report additionally included scenarios examining the global demand for U.S. LNG exports and the macroeconomic impact of increased LNG exports on the economy.

The EIA 2014 study included updated export scenarios of 12–20 Bcf/day and domestic natural gas supply scenarios from AEO2014: Low High Oil and Gas Resource, High Oil and Gas Resource, High Economic Growth, and Accelerated Coal and Nuclear Retirements. Increased exports led to increased natural gas production and prices relative to respective base scenarios as well as higher primary energy consumption and energy-related carbon dioxide (CO_2) emissions.

The Baker Institute 2015 study examined U.S. LNG exports of 12 and 20 Bcf/day. Two models were used: an international natural gas model (from the Baker institute) and a global economic model from Oxford Economics. This study outlined the international conditions that could result in a market for over 20 Bcf/day of LNG exports and examined the impact on the U.S. economy of scenarios with 12 and 20 Bcf/day of LNG exports with low gas resource recovery, high gas resource recovery, and high natural gas demand.

Using NERA's Global Natural Gas Model and the NewERA energy-economy model, the NERA 2018 study determined LNG exports for 54 different scenarios capturing a broad range of domestic and international gas supply and demand conditions and probabilities on the likelihood of each of the 54 export scenarios. In general, high levels of LNG exports corresponded to high oil and gas supply but higher prices. Since approximately 80% of the exports resulted from increased production rather than decreased demand, the general economic impact was positive across the scenarios. The report

[7] Cooper, A., Kleiman, M., Livermore, S., & Medlock III, K. B. (2015). The Macroeconomic Impact of Increasing US LNG Exports. Available at:
https://energy.gov/sites/prod/files/2015/12/f27/20151113_macro_impact_of_lng_exports_0.pdf

[8] NERA Economic Consulting. (2018). Macroeconomic Outcomes of Market Determined Levels of U.S. LNG Exports. Available at:
https://www.energy.gov/sites/prod/files/2018/06/f52/Macroeconomic%20LNG%20Export%20Study%202018.pdf

concluded that the impact on energy-intensive industries was minimal while increased investment attributed to LNG exports raised gross domestic product.

B. Purpose of Study

This current study, similar to the previous studies, is intended to serve as a reference to be considered in the evaluation of applications to export LNG from the United States under Section 3 of the NGA. DOE-FECM commissioned OnLocation, Inc., Pacific Northwest National Laboratory (PNNL), and the National Energy Technology Laboratory (NETL) to assess the economic level of U.S. LNG exports across seven scenarios representing a broad range of economic, environmental, and political scenarios, along with changes to global greenhouse gas (GHG) emissions at differing levels of U.S. LNG exports. U.S. LNG export levels were found using a global equilibrium model and were then input into the domestic model to examine the market effects of increased LNG exports including natural gas price and consumption across sectors and changes in U.S. GHG emissions. Finally, the life cycle analysis (LCA) of U.S. LNG exports was expanded to incorporate market effects from the results of this study.

Since the NERA 2018 report was published, several events have altered the explicit and implicit assumptions underpinning the global and U.S. natural gas markets. These include 1) the issuance of additional DOE LNG export authorizations; 2) the Russia-Ukraine war; 3) global and U.S. GHG policy developments; 4) technological change in production, transmission, storage, and end-use of natural gas; 5) and the passage of significant energy-related legislation in the United States (the Infrastructure Investment and Jobs Act[9] also known as the Bipartisan Infrastructure Law [BIL] and Inflation Reduction Act[10] [IRA]). This study updates previous analytical work in line with current laws and regulations, as well as economic and technology conditions using newly derived scenarios. The defined seven scenarios are listed below and described in more detail in Scenarios, Methodology, and Key Assumptions, Section A:

***Scenario 1 (S1)*: Reference Exports:** Reference scenario in which U.S. LNG exports follow EIA's AEO2023 Reference Scenario

***Scenario 2 (S2)*: Market Response:** U.S. LNG exports determined by global market equilibrium

***Scenario 3 (S3)*: High Global Demand:** U.S. LNG exports determined by global market equilibrium, higher population growth outside of the United States

***Scenario 4 (S4)*: Regional Import Limits:** U.S. LNG exports determined by global market equilibrium, global focus on maximizing consumption of local energy sources

***Scenario 5 (S5)*: Low-cost Renewables:** U.S. LNG exports determined by global market equilibrium, lower costs for variable renewable energy technologies

***Scenario 6 (S6)*: Energy Transition (Ref Exp):** U.S. LNG exports are limited to the values from the AEO2023 Reference Scenario, countries achieve emissions pledges and pursue ambitious GHG

[9] Infrastructure Investment and Jobs Act, Pub. L. 117-58, (November 15, 2021), https://www.congress.gov/117/plaws/publ58/PLAW-117publ58.pdf.
[10] Inflation Reduction Act, Pub. L. 117-169, (August 16, 2022), https://www.congress.gov/117/plaws/publ169/PLAW-117publ169.pdf.

Commented [LBD38]: "input" seems awkward. "a reference"?

Commented [PW39R38]: Reference

Commented [UP40]: What's the incumbent life cycle analysis? Is that different than the Life Cycle Analysis described in the Executive Summary?

Commented [HH41]: This paragraph discusses study intent, which is more appropriate under the "Purpose of Study" section, so I moved the header up.

Commented [UP42]: Should we say "regional energy sources" as in the bolded heading? Local seems like in-country ng source is available versus in the region.

Commented [IGC43R42]: In the way this scenario is implemented in GCAM, each GCAM region - many of which are individual countries - is incentivized to maximize production within their geographic boundaries (through constraints on imports). Hence, "locally" is probably better. But thoughts welcome.

mitigation policies consistent with limiting global warming to 1.5°C, U.S. emissions to net-zero by 2050

***Scenario 7 (S7)*: Energy Transition:** U.S. LNG exports determined by global market equilibrium, countries achieve emissions pledges and pursue ambitious GHG mitigation policies consistent with limiting global warming to 1.5°C, U.S. emissions to net-zero by 2050

Several considerations are required in interpreting this study and its results. Foremost, this study is not intended to serve as forecasts of U.S. LNG exports. Rather, it is an exercise in exploring alternative conditional "what-if" scenarios of future U.S. LNG exports and examining their implications for the global and U.S. energy and economic systems, and GHG emissions. Such scenario analysis is a well-established analytical approach for exploring complex relationships across a range of variables. In addition, the scenarios explored in this study are meant to span a range of plausible U.S. LNG export outcomes by 2050. However, they hinge on many assumptions about a wide range of domestic, international, economic, and non-economic factors such as future socioeconomic development, technology and resource availability, technological advancement, institutional change, and more. A full uncertainty analysis encompassing all of the above factors is beyond the scope of this study. This study does not attach probabilities to any of the scenarios and no inference about the likelihood of these scenarios occurring should be made. Although the scenarios explored in this study model the actual provisions in the IRA in the United States, *S6* and *S7* that incorporate countries' climate pledges do not explicitly model the actual policy instruments, sectoral measures, and regulations that countries might adopt to meet their pledges due to lack of sufficient literature on policy instruments, regulations, and mechanisms over the longer time horizon of focus in this study. Instead, these scenarios assume that countries achieve their pledges within their geographic boundaries through a cost-effective combination of sectoral transitions. The results from these scenarios could be different depending on the actual policies and mechanisms (including emissions trading) that countries might use to meet their stated pledges in reality.

Commented [IGC44]: Should we delete this section since it appears in the Exec summary as well (per Tom's comment).

Commented [PW45R44]: Best in both.

Commented [AA46]: Should this be advancement?

Commented [TC47]: Expand this discussion consistent with the discussion during and after the leadership briefing about the general considerations evaluating and interpreting model results.

Commented [IGC48R47]: I've expanded this discussion to include the points raised during the briefing as suggested.

C. Organization of the Report

This report is organized into the following sections:

- Scenarios, Methodology, and Key Assumptions
- Results
- Conclusions

Scenarios, Methodology, and Key Assumptions

Three primary analytical frameworks were used for this analysis: 1) the Global Change Analysis Model (GCAM) developed and maintained at PNNL's Joint Global Change Research Institute, 2) the National Energy Modeling System (NEMS) developed by EIA and modified for this study by OnLocation, and 3) the natural gas system LCA model developed and maintained by NETL. These frameworks and key assumptions are described below.

A. GCAM Model and Global Scenarios Design

GCAM is a model of global energy, economy, agriculture, land use, water, and climate systems.[11] These systems are represented in 32 geopolitical regions, 384 land subregions, and 235 water basins across the globe. GCAM operates in five-year time-steps from 2015 (calibration year) to 2100 by solving for equilibrium prices and quantities of various energy, agricultural, water, land use, and GHG markets in each period and in each region. Outcomes of GCAM are driven by exogenous assumptions about population growth, labor participation rates, and labor productivity in the 32 geo-political regions, along with representations of resources, technologies, and policy.

Commented [WS49]: When was this model created?

Commented [IGC50R49]: The model was first built in the 80's.

GCAM tracks emissions of 24 gases, including GHGs, short-lived species, and ozone precursors, endogenously based on the resulting energy, agriculture, and land use systems. GCAM's energy system contains representations of fossil resources (coal, oil, and gas), uranium, and renewable sources (wind, solar, geothermal, hydro, biomass, and traditional biomass) along with processes that transform these resources to final energy carriers (electricity generation, refining, hydrogen (H_2) production, natural gas processing [NGP], and district heat), which are ultimately used to deliver goods and services demanded by end use sectors (residential buildings, commercial buildings, transportation, and industry). Natural gas competes for share with other fuels in the electricity generation sector and with other fuels and electricity in the buildings, industrial, and transportation sectors. Each of the sectors in GCAM include technological detail. In every sector within GCAM, individual technologies compete for market share based on the levelized cost of a technology (see Appendix A: Global Analysis and Description of GCAM for more details). The version of GCAM used in this study also includes a representation of three carbon dioxide removal (CDR) strategies that were deployed in scenarios with emissions policies including direct air capture (DAC); bioenergy in combination with carbon capture, utilization, and storage (BECCS); and afforestation.

Commented [AA51]: Consider defining or briefly explaining the difference between these two.

Commented [IGC52R51]: That could be a distraction for this study, since biomass is not a focus of this study. More details are available in the GCAM documentation page:

http://jgcri.github.io/gcam-doc/supply_energy.html which is referenced in the first sentence of the report.

The version of GCAM used in this study includes a representation of natural gas trade that creates price-based competition between domestic and imported natural gas. This representation introduces realistic inertia in the evolution of trade from current patterns. Natural gas can be imported as LNG or through pipelines. Traded LNG is represented as a single global market. All producers of natural gas can export to a global LNG pool from which importers can import. While the price of domestic gas is based on extraction costs derived from long-term regional resource supply curves, the price of imported LNG includes costs for shipping, liquefaction, and regasification in addition to extraction costs. Traded pipeline gas is represented in six regional markets (North America, Latin America, Europe, Russia+, Africa

[11] The full documentation of the model is available at the GCAM documentation page (http://jgcri.github.io/gcam-doc/), and the description here and in Appendix A: Global Analysis and Description of GCAM is a summary of the online documentation.

and Middle East, and Asia-Pacific). Exporters of pipeline gas export to one of the six regional pipeline blocs from which importers can import. Inter-pipeline bloc trade can also occur. For example, GCAM's China region exports only to the Asia-Pacific pipeline bloc but can import from the Russia+ pipeline bloc and the Asia-Pacific pipeline bloc. These pipeline trade relationships are based on existing relationships. The price of imported pipeline gas includes the costs of building and operating pipeline infrastructure in addition to resource extraction costs. Gross exports and imports of LNG and pipeline gas are calibrated to historical data in GCAM's historical calibration year (2015). In a future model period, trade volumes evolve from historical patterns depending on future demands and prices. For the purposes of this project, historical natural gas producer prices in the United States are calibrated to the Henry Hub prices from EIA[12]; in Canada, they are calibrated to Alberta market prices from British Petroleum's (BP) *bp Statistical Review*.[13] For the rest of the world, natural gas producer prices in each GCAM region are based on the cost, insurance, and freight prices from S&P Global (see Table A-1 in Appendix A: Global Analysis and Description of GCAM).[14] In a future model period, as demand changes, the change in regional producer prices from the historical calibrated values is calculated endogenously using regional supply curves that represent increasing cost of extraction as cumulative extraction increases. GCAM also tracks turnover of trade infrastructure (e.g., liquefaction and regasification units, and pipelines). Trade infrastructure can either retire naturally or in response to economic changes (e.g., those driven by an emissions policy).

Using GCAM, this study explored seven scenarios spanning a range of plausible U.S. LNG export outcomes by 2050 (Table 2). All of study scenarios include the 2022 IRA in the United States and current emission policies in the rest of the world. The scenarios also include a constraint on Russian exports such that Russian pipeline exports to European Union (EU) declined to a level below current levels by 2035 and then remain flat, LNG exports from Russia remain flat beyond 2025, and Russian pipeline exports to the east (e.g., to China) continue to increase. The study scenarios include planned and existing LNG capacity additions in major economies including the United States, Middle East, Australia, Canada, Southeast Asia, and Africa. Socioeconomic (population and economic growth) assumptions for the United States were harmonized to the AEO2023 Reference Scenario.

Table 2. Scenario descriptions

Scenario	Description	U.S. LNG Export Volumes (Bcf/d)
***S1*: Reference Exports**	Reference scenario in which U.S. LNG exports follow AEO2023. Incorporates U.S. policy assumptions (including the 2022 IRA). Assumes existing policies and measures, globally.	Grow to 27.3 Bcf/d by 2050
***S2*: Market Response**	Assumes policies consistent with *S1*, but U.S. LNG exports are determined by global market equilibrium.	GCAM Market Response

Commented [AA53]: Or "case". The paper uses both terms.

Commented [IGC54R53]: Note to tech editor to ensure consistency across the report while referring to AEO Reference Case/ AEO Reference Scenario.

Commented [JG55R53]: @Peter Whitman - should we use Scenario or Case?

Commented [UP56]: Here the Table although the same as in Executive Summary has different coloring. Personally I think looks better blue/white versus two shades of blue throughout.

Commented [UP57]: Same comment on the 2-digits Bcf/d as I had in Executive Summary section. 1-digit would be better to show in a report.

[12] U.S. EIA (2023). Henry Hub Natural Gas Spot Price. Available at: https://www.eia.gov/dnav/ng/hist/rngwhhda.htm
[13] BP (2022). bp Statistical Review of World Energy. 71st edition. Available at: https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/statistical-review/bp-stats-review-2022-full-report.pdf
[14] S&P Global (2023). S&P Global Commodity Insights. Historical and forecasted LNG prices data sheet.

Scenario	Description	U.S. LNG Export Volumes (Bcf/d)
***S3*: High Global Demand**	Same assumptions as *S2*, U.S. LNG exports determined by global market equilibrium, but assumes higher population growth outside of the U.S.	GCAM Market Response
***S4*: Regional Import Limits**	Same assumptions as *S2*, U.S. LNG exports determined by global market equilibrium, but includes constraints on importing and exporting natural gas with a global focus to maximize use of domestic gas.	GCAM Market Response
***S5*: Low-cost Renewables**	Same assumptions as *S2*, U.S. LNG exports determined by global market equilibrium, but assumes lower capital costs for renewable energy technologies.	GCAM Market Response
***S6*: Energy Transition (Ref Exp)**	Assumes an emissions pathway consistent with a global temperature change of 1.5°C by end of century. Countries' emissions are constrained to announced GHG pledges, including the U.S. following a path to net-zero GHG emissions by 2050. NEMS follows CO_2 emissions constraint from GCAM. U.S. LNG exports are limited to the values from *S1*.	Grow to 27.3 Bcf/d by 2050
***S7*: Energy Transition**	Same emissions pathway assumptions as *S6*, but U.S. LNG exports are determined by global market equilibrium.	GCAM Market Response

The seven scenarios are as follows:

S1: Reference Exports. This scenario assumes that the U.S. LNG exports follow the trajectory from the AEO2023 Reference Scenario to grow to 27.34 Bcf/day in 2050. The AEO2023 Reference Scenario incorporated U.S. LNG export projects that were either operating or under construction as of August 2022 and then added capacity based on the cost-competitiveness of exporting U.S. LNG to the international market including an annual capacity build-constraint. More specifically, in AEO2023, LNG export facilities had a combined operating capacity of 10.3 Bcf/day with an additional 4.5 Bcf/day of operating capacity under construction. AEO2023 projected an additional 12.6 Bcf/day of operating capacity that was assumed to be constructed in response to international demand for U.S. LNG.

Commented [HH58]: For consistency, units of measurement should be given in a single way. This occurs throughout the report text, captions, and in uneditable figures as BCF/day, BCF/d, Bcf/day, and Bcf/d. I tried to match any caption text to the figure and likewise the body text to the referenced figures/tables, but I could not choose one way because of the uneditable figures. In general, Bcf/day is used in the body, with Bcf/d used in the appendices. Given time, this should be addressed in a future draft.

S2: Market Response. This scenario has assumptions consistent with *S1* and assumes economically driven, market-based outcomes for U.S. LNG exports.

S3: High Global Demand. This scenario includes the same assumptions as in *S2* but assumes a higher population growth in regions outside of the United States consistent with the "Shared Socioeconomic Pathways – 3" from Samir and Lutz.[15] This results in approximately one billion more people globally in *S3* by 2050 compared to *S1* and *S2* and explores the effects of higher U.S. LNG exports driven by higher demand for all energy sources (including natural gas) compared to *S2*.

S4. Regional Import Limits. This scenario includes the same assumptions as in *S2*, but with constraints on natural gas imports globally to maximize the use of domestically produced natural gas

[15] Samir, K. C., & Lutz, W. (2017). The human core of the shared socioeconomic pathways: Population scenarios by age, sex and level of education for all countries to 2100. Global Environmental Change, 42, 181-192.

across the world. This scenario explores the effects of lower U.S. and global LNG exports driven by global energy security concerns and trade limitations.

S5: Low-cost Renewables. *S5* includes the same assumptions as in *S2* but assumes lower capital costs for renewable energy technologies such as onshore and offshore wind, solar photovoltaic, concentrated solar power, and geothermal. This scenario explores the effects of faster technological improvements in competing technologies. While technology cost assumptions in other scenarios are consistent with the National Renewable Energy Laboratory's Annual Technology Baseline "Medium" assumptions; capital cost assumptions for onshore and offshore wind, solar photovoltaic, concentrated solar power, and geothermal technologies under *S5* are based on the "Low" assumptions.

S6: Energy Transition (Ref Cap) **and** ***S7: Energy Transition***. Both scenarios assume an emission pathway that is consistent with a global temperature change of 1.5°C by 2100 derived from published peer-reviewed literature.[16,17,18] Both of these scenarios assume that countries achieve their emission pledges as made during the 26th Conference of Parties of the United Nations Framework on Climate Change held in Glasgow, Scotland, United Kingdom. The pledges include nationally determined contributions that outline emission reduction plans through 2030, long-term strategies, and net-zero pledges through mid-century. The United States is assumed to reduce economy-wide greenhouse gas emissions by 51% in 2030 and 100% by 2050. Countries without pledges are assumed to follow an emissions pathway defined by a minimum decarbonization rate of 8% that is indicative of strong mitigation policies and significant departure from historically observed decarbonization rates. The scenarios assume that countries achieve their pledges within their geographic boundaries without trading emissions. Scenario *S6* differs from *S7* in that it also retains U.S. LNG exports to the values from *S1*. A key distinction between *S1* and *S6* is that while the former assumes the U.S. LNG exports follow the AEO2023 Reference Scenario exactly, the latter assumes the values from the AEO2023 Reference Scenario to be an upper bound. Nevertheless, *S6* enables comparisons with *S1*, and *S7* enables comparisons with *S2*.

B. NEMS Models and Analysis Methodology

NEMS is a national energy-economic model of the United States. It projects supply, demand, imports, and exports of major energy commodities and drivers such as macroeconomic conditions, world energy markets, technology choices and costs, resource availability, and demographics. NEMS includes both cost minimization representative of competitive markets and behavioral representations of the energy market.

NEMS includes four supply modules covering oil, natural gas, coal, and renewables. There are two conversion modules converting primary fuels into electricity and petroleum and other liquids into liquid fuel products, respectively. There are four demand modules covering the residential, commercial, industrial, and transportation sectors. Other modules include the macroeconomic module, emissions

[16] Fawcett, A. A., et al. (2015). Can Paris pledges avert severe climate change? Science, 350(6265), 1168-1169.
[17] Ou, Y., Iyer, G., et al. (2021). Can updated climate pledges limit warming well below 2°C? Science, 374(6568), 693-695.
[18] Iyer, G., Ou, Y., et al. (2022). Ratcheting of climate pledges needed to limit peak global warming. Nature Climate Change, 12(12), 1129-1135.

Commented [AA59]: Consider: "It projects supply, demand conversion, imports, exports of major energy commodities, **and** drivers such as macroeconomic conditions…"

Commented [DH60R59]: Agreed, added "and" to improve readability policy modules, and an integrating module that synthesizes the output across all other modules. NEMS solves iteratively to reach a general market equilibrium across the energy economy. EIA provides an archive of NEMS with source code and input sufficient to reproduce the reference and side scenarios comprising the AEO.

1. *AEO2023-NEMS*

AEO2023-NEMS is OnLocation's version of NEMS, modified to allow exogenous input of U.S. LNG exports. The AEO2023 Reference Scenario has a macroeconomic growth assumption of 1.9% average growth per year. The model has EIA's interpretation of the IRA, which includes most major provisions of the law. The model does not include carbon capture at industrial sites (ethanol, H_2, NGP, and cement) or DAC. Therefore, the IRA 45Q credit for DAC is not included. Similarly, IRA 45V hydrogen credits are also not represented in the AEO2023 version of NEMS as it does not have the hydrogen module.

2. *FECM-NEMS*

FECM-NEMS is a version of NEMS based on OnLocation's version of AEO2022's NEMS and includes updates that allow for the modeling of deep decarbonization technologies and strategies. FECM-NEMS models the IRA based on FECM's interpretation of the policy. It includes major IRA energy-related provisions including but not limited to the extension of 45Q CO_2 sequestration credits, clean vehicle tax credits, energy efficient home tax credits and rebate programs, clean energy Production Tax Credit and Investment Tax Credit, zero-emission nuclear credits, and H_2 tax credits. Additional modeling updates include provisions from the BIL such as funding for carbon capture demonstration projects, CO_2 transportation and storage infrastructure, and updated Environmental Protection Agency (EPA)/National Highway Traffic Safety Administration Corporate Average Fuel Economy standards. For consistency with updated economic assumptions, FECM-NEMS uses the low economic growth assumption from AEO2022, assuming a real gross domestic product (GDP) average growth of 1.8% per year to 2050.

Commented [JG61]: Updated to demonstrations – please confirm

Commented [JG62R61]: @Peter Whitman - is demonstrations correct? It said "demos"

FECM-NEMS represents several CO_2 mitigation technologies including carbon capture and storage (CCS), DAC, BECCS, and H_2 processes included in the Hydrogen Market Module (HMM). These technologies allow the economy modeled by FECM-NEMS to fully decarbonize and enable the modeling of scenarios with net-zero carbon emissions. Industrial carbon capture is found in the liquid fuels module, which allows for the construction of new H_2 and ethanol facilities with CCS. It also allows for existing H_2, ethanol, and NGP plants to retrofit CCS capability. The cement industry has also been modified to include CCS opportunities. Industries have the option to send captured CO_2 to an enhanced oil recovery market or store it in saline aquifers.

Commented [AA63]: This is a little duplicative of paragraph one and two of this section. Consider revising this section to eliminate repetitiveness.

Commented [DH64R63]: We reorganized this section to remove some of the redundant information

The HMM is integrated into NEMS to produce H_2 via conventional and low-carbon processes. The H_2 production technologies available in the HMM include steam methane reformation, steam methane reformation with CCS, biomass gasification with CCS, and electrolysis.

The NEMS macroeconomic module uses a commercial econometric model designed to provide economic feedback from the broader economy with input perturbations from the energy baseline provided by NEMS. *S6* and *S7* represent such profound changes that EIA's baseline is no longer useful. As a result, FECM-NEMS does not utilize the macroeconomic module when modeling net-zero scenarios.

3. *Harmonizing GCAM and NEMS*

While GCAM and NEMS are distinct models, coordination between them is necessary to maintain consistency and tie the NEMS results back to the global LNG market forecast. Harmonization efforts ensured that LNG exports (for all scenarios) and CO_2 emissions (in the net-zero scenarios) were consistent between the two models.

The AEO2023 Reference Scenario was selected to define *S1*. In AEO2023-NEMS, the AEO2023 Reference Scenario solution file was adopted for all variables. LNG exports from the AEO2023 Reference Scenario were then used as exogenous inputs into GCAM in place of endogenous estimates. For *S2* through *S7*, the process was reversed: the scenarios were first run in GCAM, from which endogenously calculated LNG export curves were taken and input exogenously into AEO2023-NEMS. The endogenous algorithm used by NEMS to calculate LNG exports was turned off for these scenarios. Since a key driver of LNG exports is the differential between domestic and world natural gas prices, domestic natural gas prices from NEMS were then compared with North American prices in GCAM. In all scenarios except *S5*, technology and resource were aligned between GCAM and the AEO2023 Reference Scenario. In *S5*, both models adjusted power generation technology assumptions consistent with the AEO2023 Low Renewable Cost Scenario.

For *S6* and *S7*, the net-zero scenarios were first run in GCAM, which uses global interactions and feedback to model U.S. LNG under a criteria of net-zero GHG by 2050. As part of the modeling process, GCAM generates a set of emissions curves that list quantities of CO_2, methane (CH_4), nitrous oxide (N_2O), and fluorinated gases emitted in various economic sectors including emissions and removals from land use, land-use change, and forestry (LULUCF). These curves were outputs of the model, although the sum of individual emissions was defined in the model inputs such that they reached or exceeded a net-zero target in 2050. The output emissions curves from GCAM were used to specify how the net-zero scenario was implemented in FECM-NEMS.

Commented [AA65]: Spell out if this is the first time mentioning these gases.

Commented [DH66R65]: Spelled out CH4 and N2O, and removed F, which is not used later in the report. Also reorganized the section slightly to improve readability

The values of CO_2 emissions from the energy sector were taken from the GCAM output and used explicitly as the carbon cap in FECM-NEMS to model the net-zero scenarios. The carbon cap curve (used to define both *S6* and *S7*) is plotted in Figure 1.

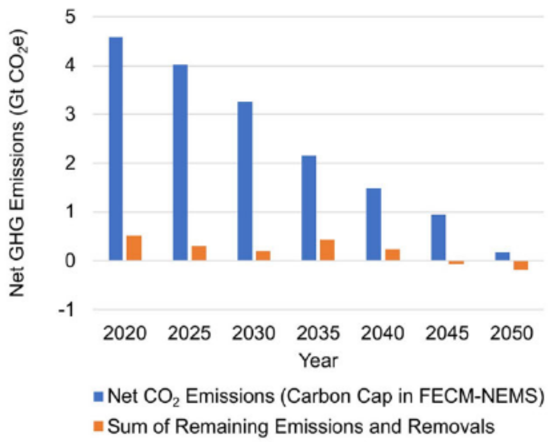


Figure 1. U.S. GHG emissions and removals in S6 and S7

Commented [JG67]: Legend needs CO2 – subscript

Commented [JG68R67]: @Peter Whitman - able to fix, or delete my comment?

Referring to this carbon cap each model year, FECM-NEMS calculates emissions and removals throughout the model and adjusts a carbon price to equalize them with the carbon cap. With this method, FECM-NEMS ensures that the CO_2 emissions from the energy sector match the corresponding emissions from GCAM. Although FECM-NEMS calculates CH_4 emissions from natural gas systems, they were excluded from the carbon cap in favor of adopting the values calculated by GCAM.

The carbon cap used in FECM-NEMS for both net-zero scenarios ended with 0.19 gigaton (Gt) CO_2 in 2050. Although this value does not equal zero, it was balanced by the sum of non-energy CO_2, non-CO_2 GHGs, and LULUCF-sector emissions and removals calculated by GCAM, which added together total -0.19 Gt CO_2 equivalent (CO_2e) (the total was negative because of large quantities of LULUCF-sector removals). The remaining emissions and removals (non-energy CO_2, non-CO_2 GHGs, and LULUCF) were treated as exogenous to FECM-NEMS and could be added with the endogenous CO_2 emissions to calculate net total GHG emissions (which would equal near-zero in 2050). The sum of non-energy CO_2, non-CO_2 GHGs, and LULUCF-sector emissions and removals is also plotted in Figure 1.

C. NETL LCA Model Methodology

Commented [TC69]: I believe Tim has had discussions with the modeling team since adding comments to this draft, the comments here may have already been shared with the team.

Past life cycle studies conducted by NETL on natural gas and LNG have been attributional studies that estimate the emissions and other impacts associated with current units of natural gas/LNG delivered. These LCA studies 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 different sources of natural gas compete in the market, or 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 GHG emissions. As part of this study, these consequential effects were estimated by tracking differences in global GHG emissions and quantities of LNG exported from the GCAM results.

This section details the various existing representations of the natural gas supply chain within the context of the NETL Natural Gas model and GCAM. The purpose of documenting these representations is to subsequently apply the insights from GCAM to the NETL LCA framework.

1. *Past NETL Natural Gas Life Cycle Reports*

As shown in the top half of Table 3, the NETL Natural Gas model[19] is separated into five stages that generally align with categories used in other federal efforts such as EPA's Greenhouse Gas Reporting Program[20] and Greenhouse Gas Inventory.[21] Results of this model are provided for two scopes: Production through Transmission (e.g., for large-scale industrial users, like power plants and LNG facilities that are directly connected to a pipeline), and Production through Distribution (e.g., for residential or smaller industrial users where the natural gas is delivered through smaller distribution pipelines). Results are provided for various techno-basins of production, regions, and U.S. average production, using a variety of Intergovernmental Panel on Climate Change (IPCC) Assessment Report Global Warming Potential (GWP) values on 100-year or 20-year basis.

In addition, past work by NETL modeled the additional processing stages to produce and deliver LNG, adding another four stages in the bottom half of Table 3.

Commented [AA70]: Consider adding as parenthetical to the title of Table 3 - (NETL Natural Gas Model).

Commented [ST71]: The 2020 report and model are not public. The reference will need updated upon release of the 2020 report.

I checked the ISSST Presentation and it is marked "do not cite" and does not contain the production thru transmission result of 7.4 g. Not a good reference.

Evaluating U.S. Natural Gas Environmental Performance, ISSST 2023 Conference, June 14, 2023, Fort Collins, CO.

Commented [SM72R71]: We believe that the 2020 report will be released imminently, and thus available when this LNG study is released.

Commented [AA73]: Spell out because this is the first time mentioning the IPCC.

Table 3. Natural gas and LNG 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, dehydration, natural gas liquids 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 NGP and compression after removal from storage before injection into the transmission pipeline network.
Stage Name	**Description**
Distribution*	Movement of gas from transmission or storage facilities to city gates for subsequent delivery to smaller consumers via small diameter pipelines (*may or may not be included depending on scope).

[19] Khutal, H., et al. Life Cycle Analysis of Natural Gas Extraction and Power Generation: U.S. 2020 Emissions Profile. National Energy Technology Laboratory, Pittsburgh, July 7, 2023
[20] U.S. EPA, Greenhouse Gas Reporting Program, https://www.epa.gov/ghgreporting, last accessed Sept 1, 2023.
[21] U.S. EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks, https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks, last accessed Sept 1, 2023.

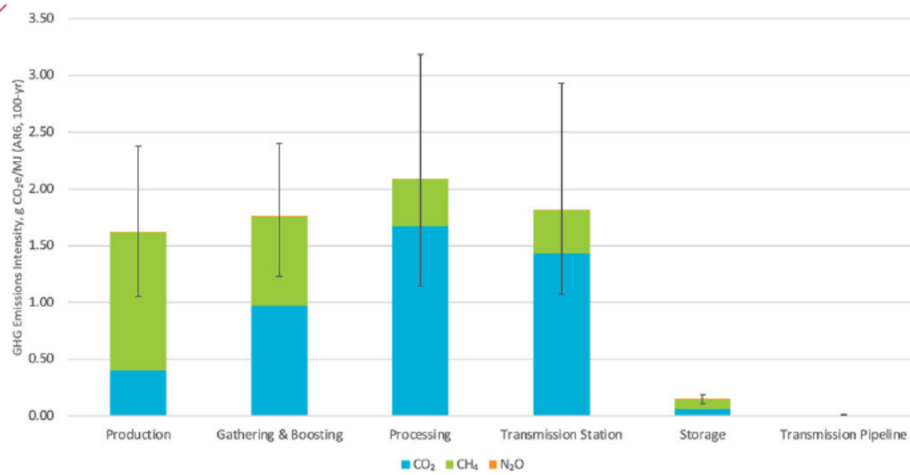
Additional Stages to Produce and Deliver LNG	
Liquefaction	Pre-treatment of gas, liquefaction to low temperatures and storage.
Loading/Unloading	Process to load (and unload) LNG to and from tankers to facilities.
Ocean Transport	Shipment of LNG on ocean-going vessels of varying technology types to distant ports for subsequent regasification. Depending on technology, may use LNG as fuel.
Regasification	Regasification of LNG and injection into transmission pipelines.
Destination Transmission/ Distribution	Similar processes as described above, and not functionally different than as described for the natural gas-only part.

Quantitatively, the NETL Natural Gas model has estimated ranges of GHG emissions by species and by stage for the domestic natural gas supply chain as shown in Figure 2. Given the scope of domestic natural gas production through the transmission stage, the mean U.S. average total CO_2e emissions are about 7.44 grams (g) CO_2e/megajoule (MJ) (IPCC Sixth Assessment Report [AR6], 100-year basis [AR6-100]), with a confidence interval of the mean of 4.6–11.1 g CO_2e/MJ. The GCAM results generated in this study estimated GWP intensity of natural gas extraction in different geographic regions of the United States, which have higher or lower intensity, as compared to the U.S. average. However, these results are in terms of higher heating value (HHV) of natural gas, while GCAM uses lower heating value (LHV), so it needed to be subsequently adjusted, resulting in a value of 8.18 g CO_2e/MJ (AR6-100, LHV basis). Further discussion of these adjustments are discussed below.

Commented [ST74]: Report the LHV result here that aligns to GCAM.

Need to provide/cite the HHV to LHV values for the adjustment factor.

Commented [SM75R74]: .



Commented [ST76]: Y-axis: units should read g CO2e/MJ before AR6, 100-year.

CO2e: removed hyphen between the "2" and "e".

Legend: need to subscript "2" and "4".

Figure 2. Life cycle GHG emissions from the 2020 U.S. average natural gas supply chain, HHV basis (Source: NETL 2023)

Past work by NETL also estimated the GHG emissions implications of the additional stages to produce and deliver U.S. 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 scenarios (LNG shipped relatively short distances has a significantly smaller GWP footprint than when shipped long distances). Using data from the 2019 NETL LNG report[22] and adjusting to the 2020 NETL Natural Gas model and EPA Greenhouse Gas Reporting Program basis used here, LNG shipped from New Orleans to Rotterdam (8,990 kilometers) would be expected to result in 20 g CO_2e/MJ delivered to regasification facility (AR6-100, LHV) 18.1 g CO_2e/MJ (AR6-100, HHV). In short, the additional processes and natural gas needed to liquefy and ship natural gas to Rotterdam adds about 9.9 g CO_2e/MJ delivered (AR6-100, LHV) or 9 g CO_2e/MJ delivered (AR6-100, HHV). The GHG emissions intensity result on a per MJ NG delivered to liquefaction plant basis is 8.2 g CO_2e/MJ (AR6-100, LHV) but accounting for NG losses that occur in the downstream stages results in a higher volume of NG needed upstream, leading to a contribution of 10.2 g CO_2e/MJ NG delivered to the regasification facility (AR6-100, LHV) by the upstream NG supply chain stages (production through transmission network).[23] 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.

The previous NETL work on natural gas cited above are attributional analyses of the domestic natural gas system. The results sought to identify and attribute the emissions associated with the various unit processes that created them. These methods differ in scope from consequential analysis that more broadly considers the global changes in GHG emissions when additional volumes of U.S. natural gas are produced and delivered across the world, or, in other words, the market-based effects of producing domestic natural gas and exporting it. Further discussion on how the LCA section of this study can support consequential analysis is discussed in Results, Section G.

2. *Market Adjustment Factors*

To quantify the global market effects associated with increasing exports of U.S. LNG, the GCAM results were used to estimate the change in global GHG emissions per unit of LNG exported between various scenarios. This market adjustment factor (MAF) is defined as:

$$MAF_{scenario\ n} = \frac{Global\ Emissions_{scenario\ n} - Global\ Emissions_{scenario\ 1}}{U.S.\ LNG\ Exports_{scenario\ n} - U.S.\ LNG\ Exports_{scenario\ 1}}$$

and represents a ratio of the change in GHG emissions for a given scenario compared to a base scenario, versus the change in U.S. LNG exports between the same two scenarios. For example, a comparison of *S2* versus *S1* would compare the differences in GCAM values for these two scenarios. The MAF can be calculated for every model year (2015–2050) and can also use linearly interpolated values of emissions and U.S. LNG exports for the non-modeled years.

[22] Roman-White, S., Rai, S., Littlefield, J., Cooney, G., & Skone, T. J. (2019). Life cycle greenhouse gas perspective on exporting liquefied natural gas from the Unites States: 2019 update. NETL, Pittsburgh, September 12, 2019.
[23] Results from Roman-White 2019, Exhibit A-2, adjusted from g CO_2e/MWh to g CO_2e/MJ using heat rate of 145 kilogram natural gas/MWh, and higher heating value of 54.3 MJ/kilogram.

Commented [ST77]: Please confirm that the US upstream was also adjusted to use the 2020 NG profile, as well as the GWP reference.

This change should also be noted in footnote 20.

Commented [JG78]: Unsure if this is technical language or error - "delivered" twice = grammar issue or 1) LNG delivered and 2) emissions delivered?

Commented [SM79R78]: I know I just used a synonym but hopefully ok? Kind of jargon, yes.

Commented [JG80]: Other data uses one decimal point - change to 7.4?

Commented [SM81R80]: You found one of our loose ends :-) Updated and edited now.

Commented [AA82]: A word appears to be missing here.

Commented [SM83R82]: No but reworded paragraph to hopefully make this more clear.

Commented [LBD84]: Unclear what these two dimensions/adjectives are; could this just be "global market effects"?

Commented [ST85]: Page 51: MAF is defined as "market effect adjustment factor". Recommend removing effect for consistency with in the report.

Commented [ST86]: The equation below's font size is too large to match the document style.

RESULTS

The following sections describe the results of the global analysis using GCAM, the U.S. analysis using NEMS, and the LCA. The discussion begins with a description of U.S. LNG export outcomes across scenarios (Section A) followed by highlights of the implications of the availability of additional U.S. LNG in the global market found by comparing *S1* and *S2* (Section B). *S6* and *S7* are discussed to illustrate the implications of additional U.S. LNG in the global market under a global transition toward 1.5°C (Section C and Section D). Finally, results from the remaining scenarios (*S3*–*S5*) are discussed (section E).

A. U.S. LNG Exports

Across all scenarios, the United States is a net exporter of natural gas. As shown in Figure 3, U.S. LNG exports increase beyond existing and planned capacity in all scenarios by 2050, except *S1* in which U.S. LNG export volumes follow AEO2023 and in *S6* in which export volumes were limited to AEO2023 by design. Across all the scenarios, LNG exports range 23–49 Bcf/day. This range is consistent with EIA's analysis (15–48 Bcf/day).[24]

Commented [LBD87]: This stated order doesn't seem to start until after Section A?

Maybe it could be better explained here -- this seems to apply to Section B (S1 & S2) and C/D (S6 & S7), and then all scenarios together in other sections.

Section A treats the 7 scenarios in numerical order for export volumes, setting the stage for following sections.

Commented [IGC88R87]: Thanks. We've clarified this.

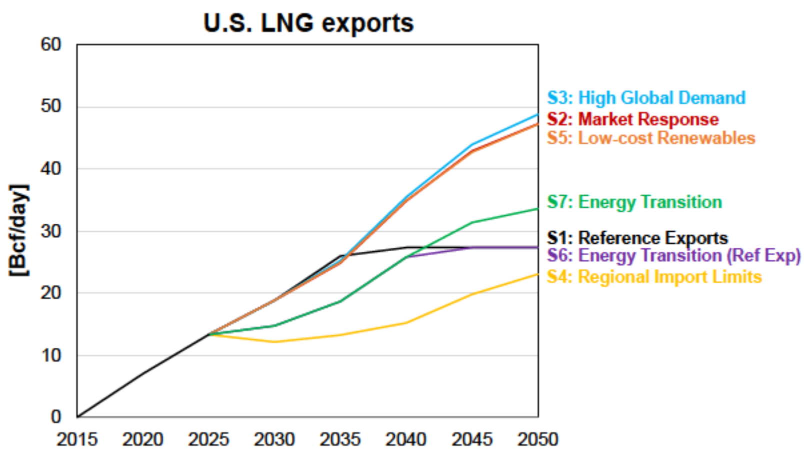
Commented [LBD89]: S3? S2 would have been discussed along with S1.

Commented [IGC90R89]: Agreed. Thanks.

Commented [UP91]: Shouldn't this be 49 Bcf/d based on S3 scenario (see page 21)?

Commented [IGC92R91]: Yes. Thanks.

[24] U.S. EIA. (2023). Issues in Focus: Effects of Liquefied Natural Gas Exports on the U.S. Natural Gas. Available at: Markethttps://www.eia.gov/outlooks/aeo/IIF_LNG/



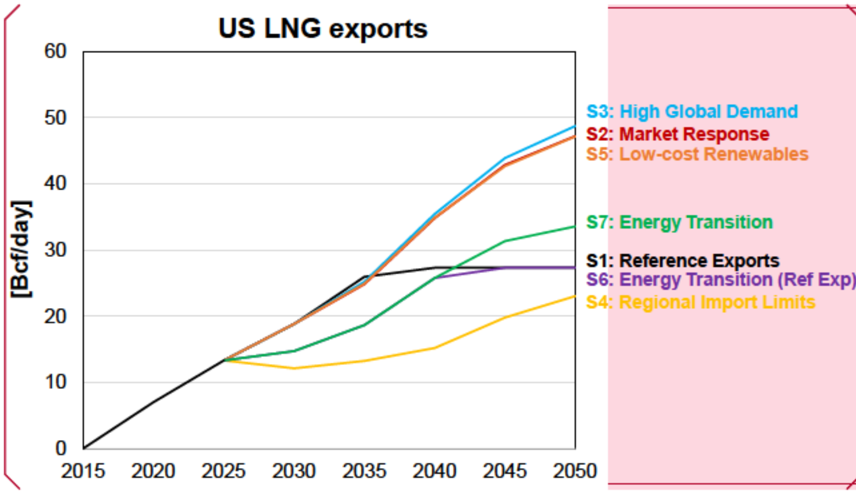


Figure 3. U.S. LNG exports across the scenarios. Note that the U.S. LNG export outcomes for S2 and S5 are very close to each other

Under *S2,* in which all outcomes—including U.S. LNG exports—are economically driven and market-based, U.S. LNG exports increase to approximately 47 Bcf/day in 2050.

U.S. LNG exports under *S3*, the scenario with increased global population, increase to 49 Bcf/day in 2050, emerging as the upper bound. With higher population assumptions in *S3*, total energy demand—and consequently natural gas demand—outside the United States increases compared to *S2*, resulting in an increase in U.S. LNG exports to satisfy the increased international demand. However, the increase in demand is not proportional to the increase in population because part of the higher demand in *S3* is supplied by an increase in international production.

Commented [HH93]: US should be U.S.

Commented [JG94R93]: @Daniel Hatchell - Is this something you could quickly replace?

Commented [DH95R93]: @Jasmine Greene I believe this plot came from the PNNL team. I'll reach out to them about getting it updated here and in the ES

U.S. LNG exports under *S4* increase only to approximately 23 Bcf/day in 2050, emerging as the lower bound. The lower increase in U.S. LNG exports in *S4* compared to other scenarios is driven by international limits on natural gas imports to maximize the use of locally produced natural gas.

Commented [UP96]: Is this an assumption where all importing countries have readily available locally-produced natural gas they can use instead? Should we say regionally vs locally?

Commented [IGC97R96]: The detailed assumptions for this scenario are in Table A-1. I am OK with "locally" but open to other thoughts.

U.S. LNG exports under *S5* increase to approximately the same level as *S2* in 2050. This is because cheaper solar and wind technologies in this scenario mostly displace fuels other than natural gas (e.g., biomass). Hence, the demand for natural gas, and consequently U.S. LNG exports, remains materially unaffected compared to *S2*. Under *S7,* which assumes a global transition toward 1.5°C, U.S. LNG exports continue to increase, albeit at a lower level than *S2,* to approximately 34 Bcf/day in 2050. As discussed below, the lower increase in U.S. LNG exports in this scenario compared to *S2* is driven by the economy-wide transition to low-carbon fuels to meet emission reduction commitments and pledges.

Commented [AA98]: Recommend spelling out instead of using symbol.

B. Global Natural Gas Consumption, Production, and Trade Under *S1* and *S2*

As shown in Figure 4, under *S1*, production, consumption, and trade of natural gas increases in all regions, globally driven by growing demands in the electricity generation, industrial, and buildings sectors (see Figure A-1 in Appendix A: Global Analysis and Description of GCAM). Under *S1*, U.S. LNG exports follows the AEO2023 Reference Scenario to grow to 27.3 Bcf/day by 2050 (by design).

Commented [IGC99]: Note to tech editor: Please make sure we're consistent throughout about AEO2023 Reference case vs. AEO2023 Reference scenario.

Commented [WS100]: Global comment: this report consistently uses bar charts rather than actual figures. Can we include all these figures in appendices?

Commented [IGC101R100]: Yes.

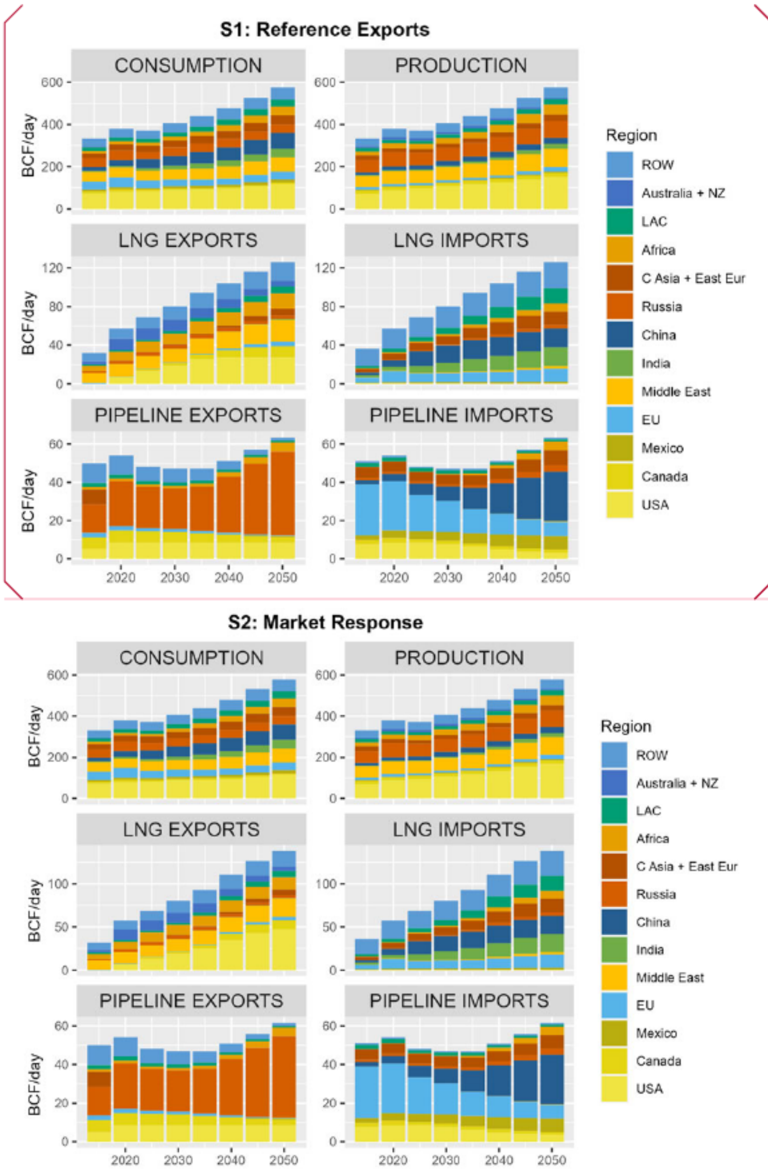


Figure 4. Natural gas consumption, production, and trade by region under S1 (upper) and S2 (lower). Conversion factors are as follows: 1 Tcf/yr = 2.74 Bcf/day and 1 Bcf/day = 0.36 Tcf/yr

Commented [WS102]: S1 shows global gas consumption increasing to 2050 (and maybe beyond?). Even S6 and S7 seem to show global gas consumption plateauing in 2045 (but not decreasing event then). Meanwhile, we understand that this month the IEA will release a global outlook document that will project gas consumption peaking this decade. This seems like a vast discrepancy and perhaps one that should be addressed. Is it feasible to run another scenario? If not, how would we defend the validity of our assumptions as compared to those of others?

Commented [IGC103R102]: Please see our response in the consolidated response document.

Commented [JG104]: I shrunk these down a bit to keep them together on one page - otherwise, it's not clear that Figure 4 refers to both

Under *S2*, in which U.S. LNG exports are determined by market equilibrium, U.S. natural gas production and LNG exports increase compared to *S1* to satisfy the growing demands of natural gas globally. Under *S2*, U.S. LNG exports grow to approximately 47 Bcf/day by 2050. Figure 5 shows the changes in natural gas consumption, production, and trade by region in *S2* versus *S1*. The additional U.S. LNG exports in *S2* compared to *S1* is 20 Bcf/day in 2050. The availability of additional U.S. natural gas in the global natural gas market at competitive prices results under *S2* in a reduction in production and LNG exports from other parts of the world compared to *S1*. The increased availability of U.S. LNG under *S2* also results in higher LNG imports and reduced pipeline trade outside of the United States. In addition, natural gas consumption outside of the United States increases by 7 Bcf/day compared to *S1*. However, U.S. natural gas consumption under *S2* decreases (by 3 Bcf/day in 2050) driven by domestic price increases in response to increased domestic production. Thus, the net increase in global natural gas consumption in *S2* compared to *S1* is 4 Bcf/day. Compared to the total natural gas consumption globally in 2050 in *S1* (574 Bcf/day), this change is <1%. Consequently, global primary energy consumption and GHG emissions under *S2* do not change much compared to *S1*, as shown in Figure 6.

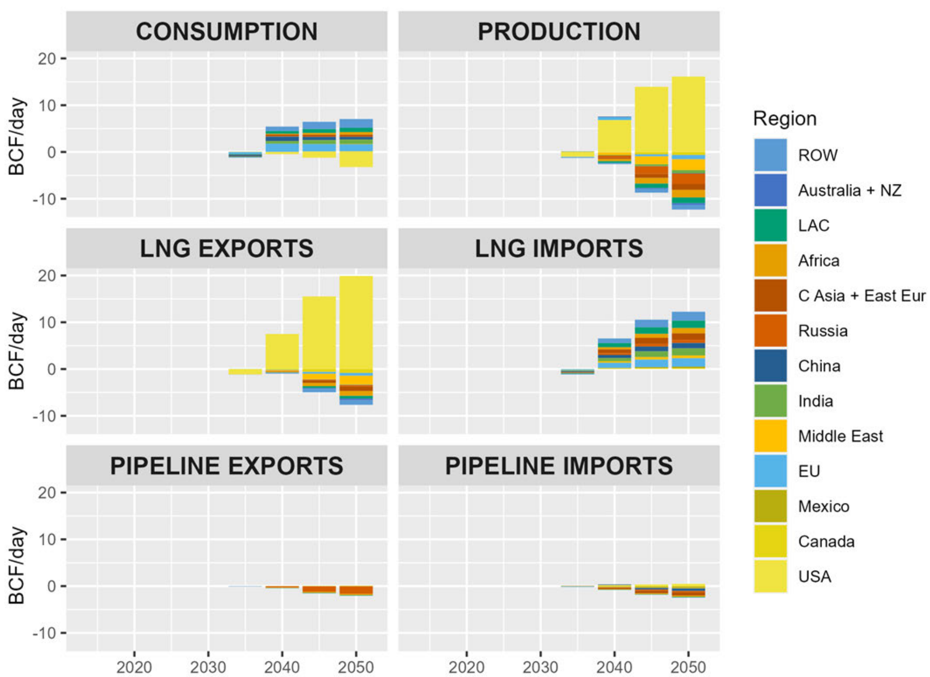


Figure 5. Changes in natural gas consumption, production, and trade by region in S2 vs. S1. Conversion factors are as follows: 1 Tcf/yr = 2.74 Bcf/day and 1 Bcf/day = 0.36 Tcf/yr

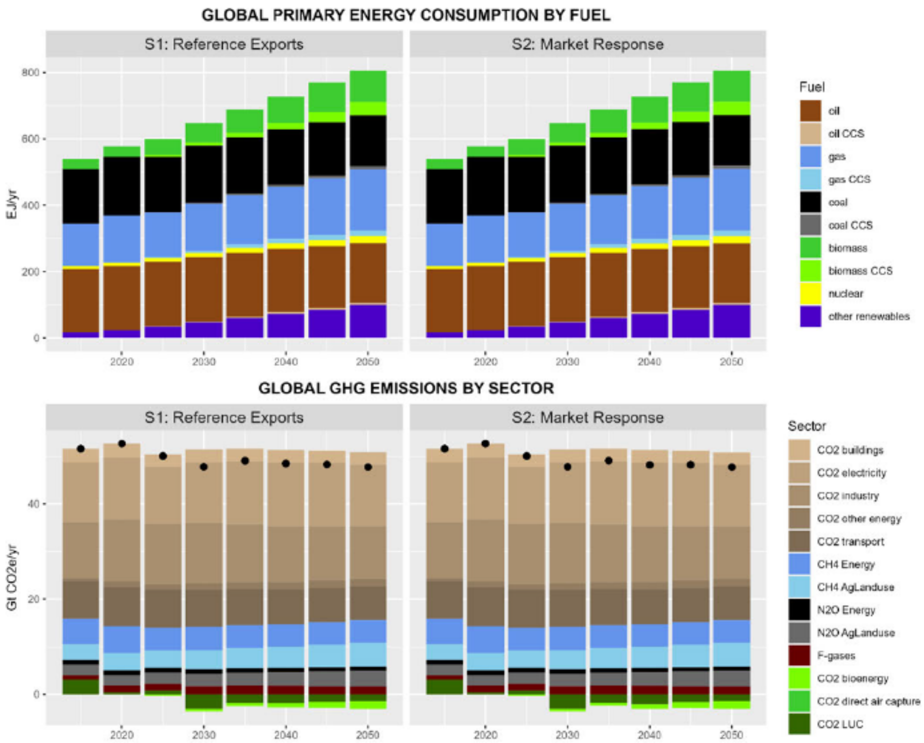


Figure 6. Global primary energy consumption by fuel and GHG emissions by sector under S2 and S1. Changes in S2 relative to S1 are <1% and are presented in the data tables in Appendix A: Global Analysis and Description of GCAM. Net GHG emissions are shown as a dot in each bar

C. Global Primary Energy Consumption by Fuel and GHG Emissions by Sector Under *S6* and *S7*

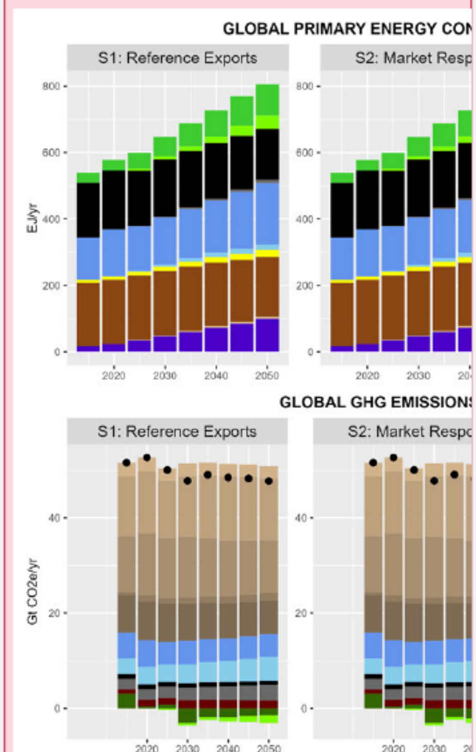
Under *S6* and *S7*, global GHG emissions from all sectors of the economy are reduced significantly compared to *S1* and *S2,* as shown in Figure 7 and Figure 8. This is by design as these scenarios are assumed to include emissions pledges and constraints on emissions consistent with limiting global temperature change this century to 1.5°C. Under these scenarios, although global GHG emissions are net-positive (approximately 17 Gt CO_2e), global CO_2 emissions are approximately zero in 2050. These global emissions outcomes are broadly consistent with 1.5°C scenarios in the literature.[25]

[25] Riahi et al. 2022, Chapter 3 in the Sixth Assessment Report of the IPCC

Commented [ST105]: Need S2 minus S1 delta figures.

Commented [IGC106R105]: We prefer not to show the delta figures here since the changes very small (<1%) and within solution tolerance. We instead point to the data tables in the appendix. In addition, the revised text now includes a description of the small changes.

Below is a version with deltas. As you can see, the deltas are really small and can be distracting.



Commented [WS107]: Figure 6 is almost impossible to read. It seems like there are differences between S1 and S2 but the reader can't judge the magnitude just by looking at the bar charts.

Commented [IGC108R107]: We have included data tables for this all other figures in the Appendix. We have also included additional panels in Figure 6 showing the changes in S2 relative to S1.

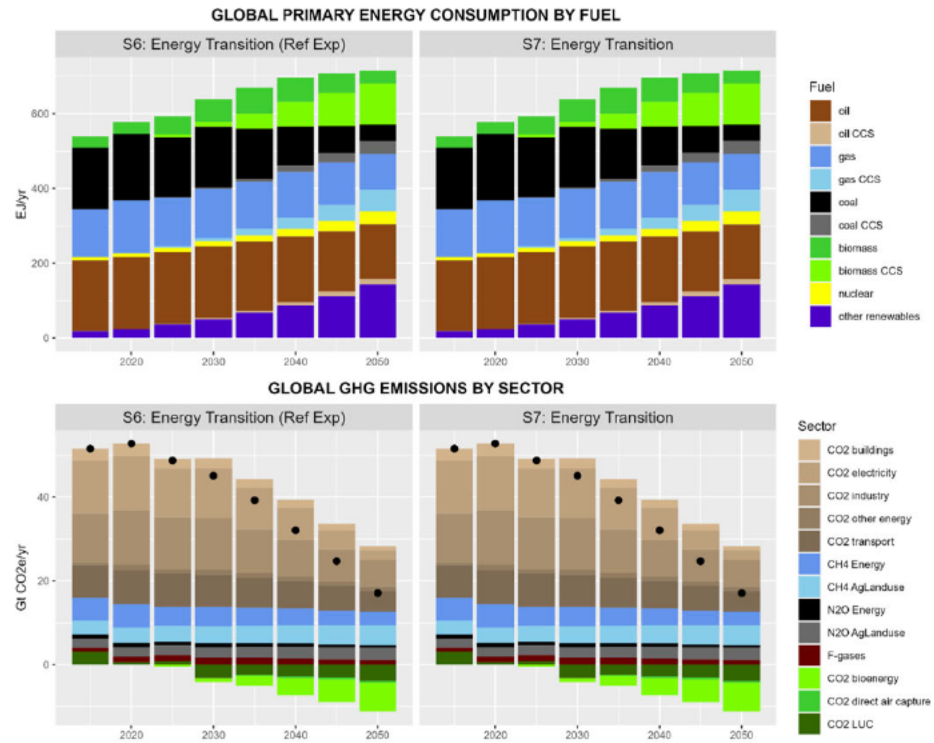
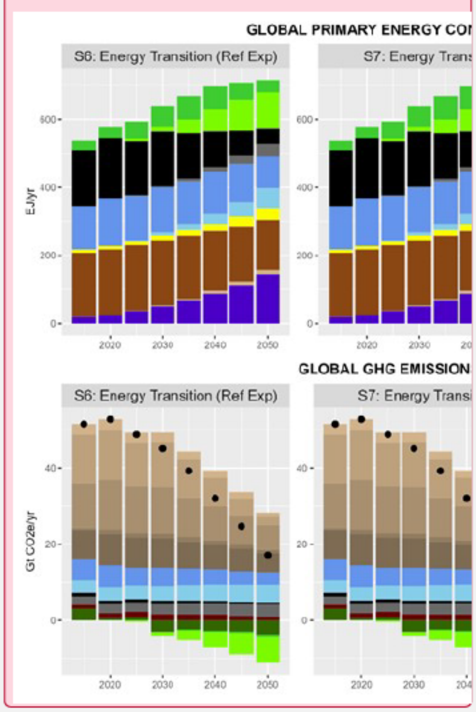


Figure 7. Global primary energy consumption by fuel and GHG emissions by sector under S6 and S7. Changes in S7 relative to S6 are presented in the data tables in Appendix A: Global Analysis and Description of GCAM. Net GHG emissions are shown as a dot in each bar

Commented [ST109]: Need S7 minus S6 delta figures.

Commented [IGC110R109]: We prefer not to show the delta figures here since the changes very small (<1%) and within solution tolerance. We instead point to the data tables in the appendix. In addition, the revised text now includes a description of the small changes.

Below is a version with deltas. As you can see, the deltas are really small and can be distracting.



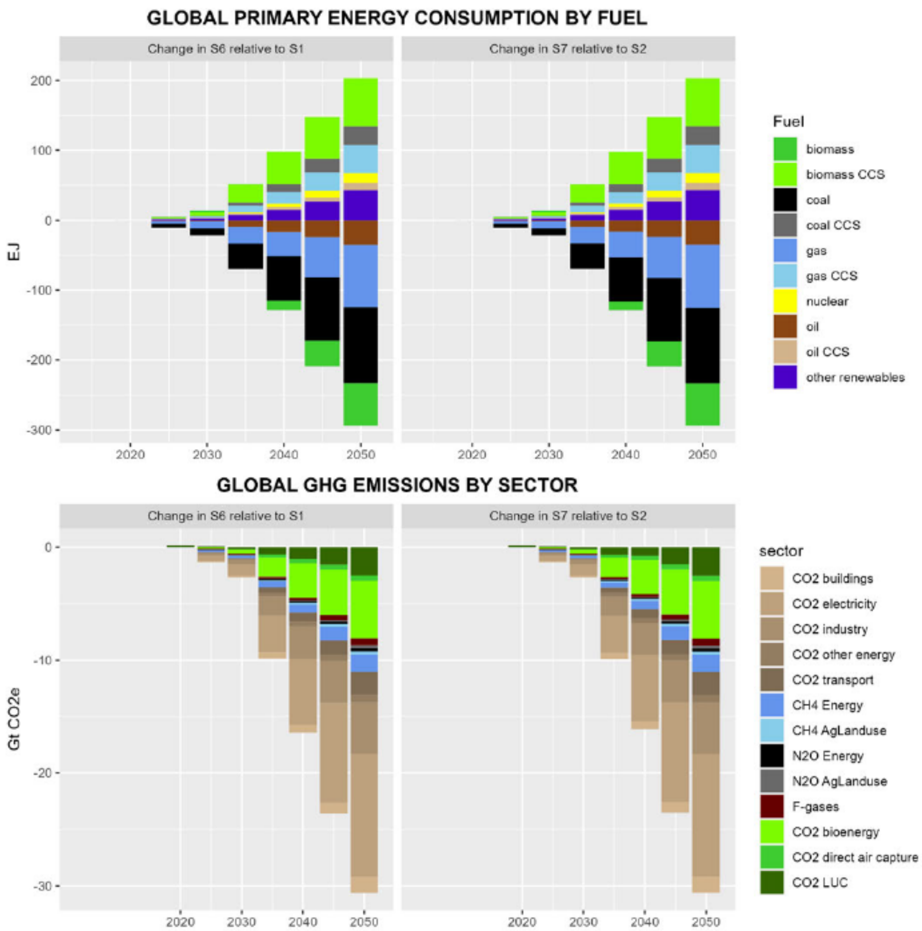


Figure 8. Changes in global primary energy consumption and GHG emissions under S6 and S7 relative to S1 and S2 respectively

These scenarios are characterized by a combination of the following decarbonization strategies: 1) a reduction in fossil fuel consumption without carbon capture, utilization, and storage (CCUS); 2) increased deployment of CCUS with fossil fuels; 3) increased deployment of renewables; 4) a net reduction in energy consumption; and 5) increased deployment of CDR applications such as BECCS, afforestation, and DAC, compared with *S1* and *S2*. Notably, the scale and distribution of CDR deployment varies by type and region. By 2050, about 6.8, 4, and 0.4 Gt CO_2e, respectively of BECCS, afforestation, and DAC are deployed globally in *S6* and *S7*, as shown in Figure 9. While BECCS and afforestation are distributed more evenly across regions, most of the DAC is deployed in the United States primarily due to the availability of carbon storage.

Commented [ST111]: Recommend removing this figure. It is not related to LNG Exports. This result can easily be mis-interpreted given the focus of the project. This project is not about how effective climate policy is.

Commented [IGC112R111]: I think this figure is helpful in explaining that gas consumption in S6 and S7 are significantly lower than S1 and S2. Yet, demand for gas continues to grow because of deployment of gas-CCUS. That said, I do not have a strong opinion on this and happy to move this to the Appendix. If we decide to do that, we will need to work on figure numbering throughout the report.

Commented [UP113]: Is this discussion related to Figure 8 or 9? Looks like one of these charts was dropped in and has no written content. All charts should be referenced with content. Prefer no drop and run charts😉.

Commented [IGC114R113]: This should point to Figure 9.

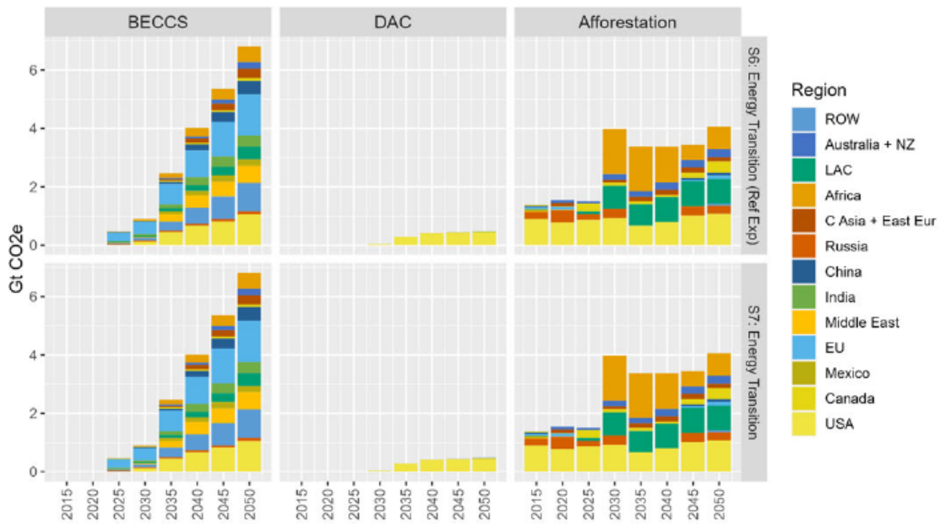


Figure 9. CDR deployment by type and region in S6 and S7

Interpretation of the energy transformation and emissions outcomes under *S6* and *S7*—particularly those surrounding the regional and sectoral allocations—requires two careful considerations. First, these scenarios do not explicitly model the actual policy instruments and mechanisms that countries might adopt to meet their pledges due to lack of sufficient literature on policies and regulations over the longer time horizon of focus in this study. Instead, these scenarios assume that countries achieve their pledges cost-effectively through a combination of decarbonization strategies discussed above. Second, *S6* and *S7* do not assume the availability of any emissions trading or offset mechanisms for countries to meet their pledges. Hence, countries with net-zero pledges—such as the United States—are assumed to meet those pledges in the stated target years through a combination of decarbonization strategies discussed above including CDR deployment within their own geographic boundaries. The sectoral and geographic distributions of energy system transitions and emissions outcomes could be different depending on the actual policies and mechanisms that countries use to meet their pledges in reality.

D. Global Natural Gas Consumption, Production, and Trade Under *S6* and *S7*

As shown in Figure 10 and Figure 11, under *S6* and *S7*, natural gas consumption decreases compared to *S1* and *S2* in most regions largely driven by official net-zero pledges that require complete decarbonization of energy systems by 2050. However, in some regions with net-zero pledges that extend beyond 2050 (e.g., India), natural gas demand continues to grow through 2050 and consumption does not change much compared to *S1* and *S2*. Globally, although natural gas consumption in *S6* and *S7* is lower compared to *S1* and *S2*, it continues to grow due to the deployment of natural gas with CCUS in power and industrial sectors and DAC applications (see Figure A-2 in Appendix A: Global Analysis and Description of GCAM). The lower natural gas consumption in *S6* and *S7* compared to *S1* and *S2* results in lower global production, LNG exports, and LNG imports.

Commented [ST115]: Need delta figures. The key message is "what changed" when we increase exports. I can not ascertain this result from the current results display.

The question of how/if renewables or other energy sources are displaced by natural gas is also not apparent in any of these results.

What countries changed their energy consumption profile because the US increased exports?

Did each countries response to change in energy consumption pattern increase or decrease their GHG emissions footprint?
...what sectors within each country?

Next - figures are nice, but would like to see full tabulated results in an Excel workbook be made available to provide transparency to the public on GCAM, NEMS, and LCA results.

Commented [IGC116R115]: **Need delta figures. The key message is "what changed" when we increase exports. I can not ascertain this result from the current results display.**

Response: As discussed in a previous response, we prefer not showing the delta figures here because the changes are really small (less than 1%) and within solution tolerance. Instead, we point to the data tables in the appendix which contain differences.

The question of how/if renewables or other energy sources are displaced by natural gas is also not apparent in any of these results.

Response: Again, these changes are really small and within solution tolerance. The data tables in the appendix contain these details.

What countries changed their energy consumption profile because the US increased exports? Did each countries response to change in energy consumption pattern increase or decrease their GHG emissions footprint?
...what sectors within each country?

Response: Note again that gas consumption changes, fuel substitution, and emissions changes in response to additional US LNG exports are all really small (<1%) and within solution tolerance. The description in this

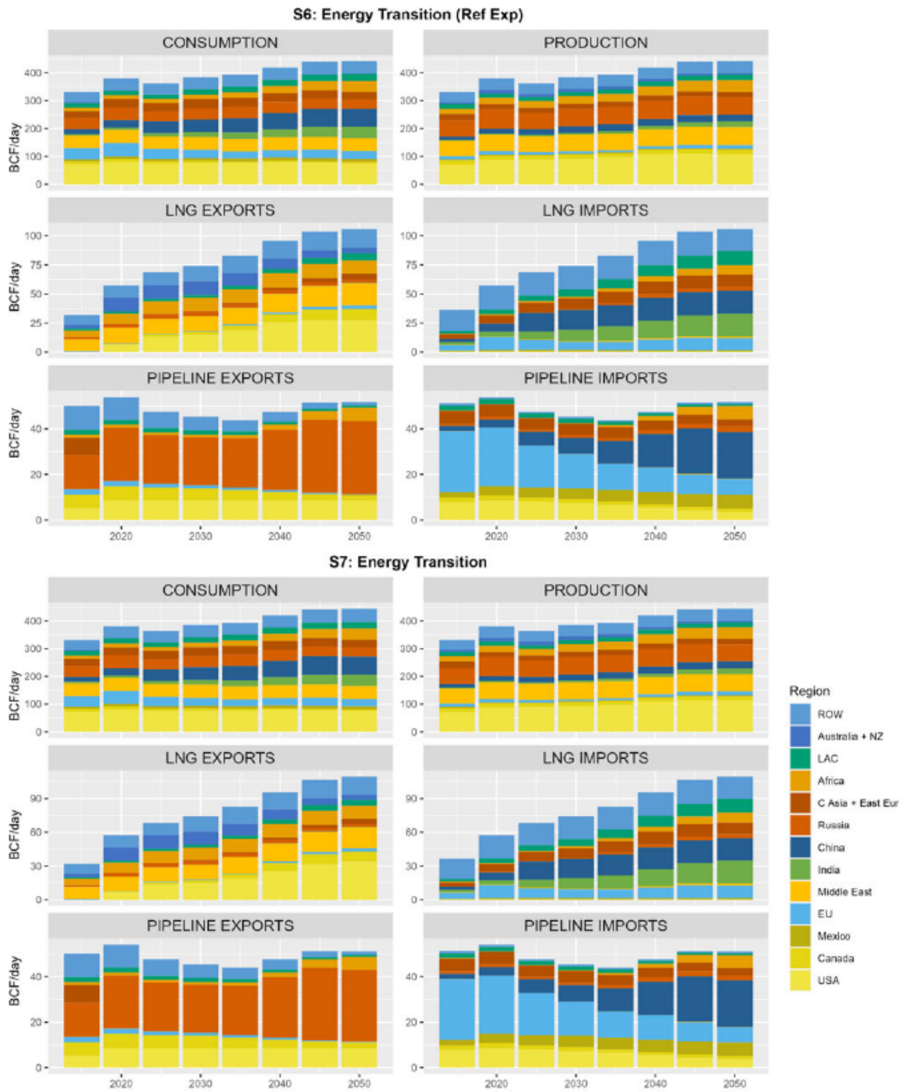


Figure 10. Natural gas consumption, production, consumption, and trade by region under S6 and S7. Conversion factors are as follows: 1 Tcf/yr = 2.74 Bcf/day and 1 Bcf/day = 0.36 Tcf/yr

Commented [UP117]: Needs charts check. Looks like something going on with the Consumption and Production axis that are labeled as Bcf/d but with a max of 150 as the vertical axis (the way it was in prior draft in Tcf vs now Bcf/d). See also similar charts showing 600 Bcf/d on pages 22 and 23 for vertical axis which make more sense? Also the LNG exports between S6 and S7 hard to tell any difference with such small charts. They look identical with similar axis labels although difference may be small between 27.3 and 34 Bcf/d for the U.S.

Commented [IGC118R117]: Corrected.

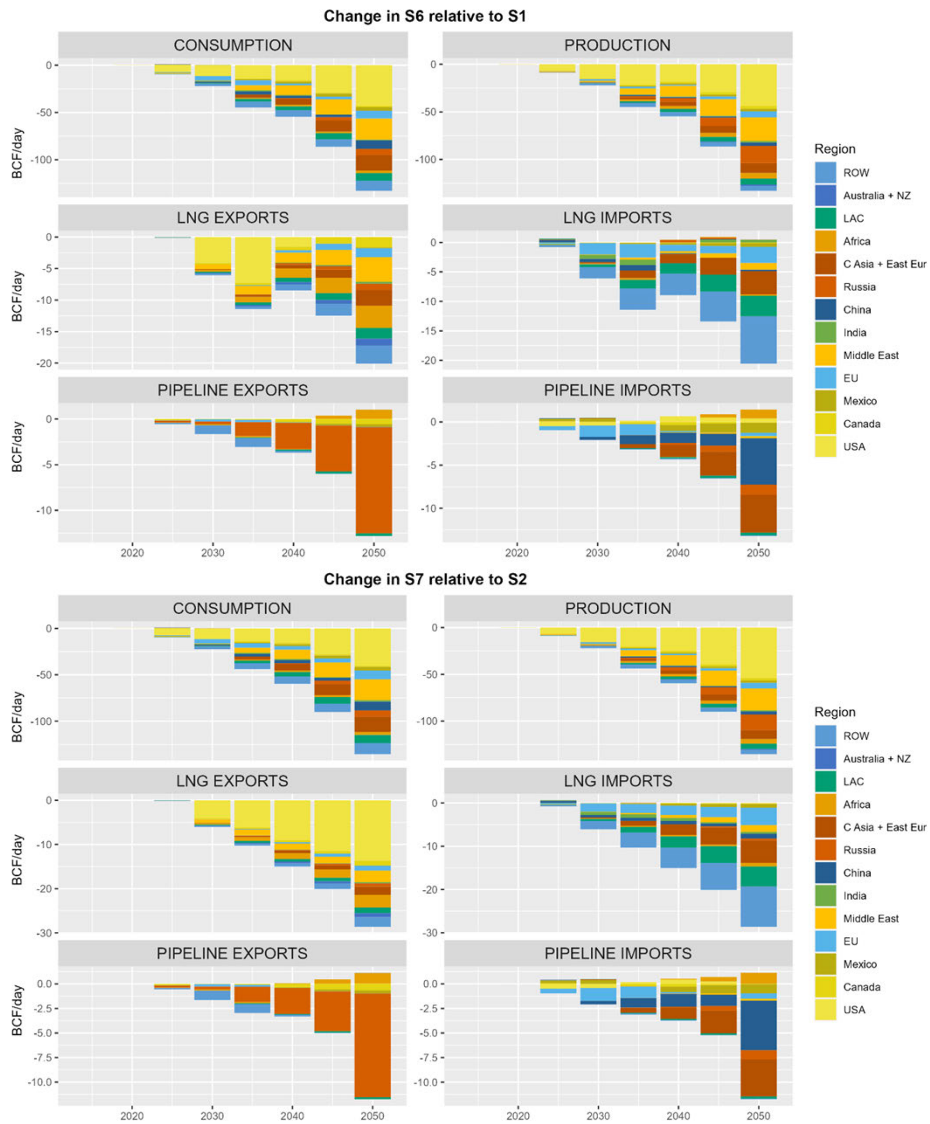


Figure 11. Changes in natural gas consumption, production, and trade by region: S6 vs. S1 and S7 vs. S2. Conversion factors are as follows: 1 Tcf/yr = 2.74 Bcf/day and 1 Bcf/day = 0.36 Tcf/yr

As shown in Figure 12, *S6* and *S7* differ in the role of U.S. LNG exports in the global natural gas market. By 2050, U.S. LNG exports in *S6* are not different from *S1* because this scenario assumed the *S1* values (which are based on the AEO2023 Reference Scenario) as an upper bound. Under *S7*, which assumes economically driven outcomes, U.S. LNG exports increase by 6.3 Bcf/day to 34 Bcf/day in 2050. Similar to the comparison between *S1* and *S2*, the availability of additional U.S. LNG in *S7* results in a reduction in natural gas production, reduction in LNG exports, increase in LNG imports, and reduction in pipeline trade outside of the United States compared to *S6*. The availability of additional U.S. LNG in *S7* also results in a net increase in natural gas consumption of 1.6 Bcf/day outside of the United States. In addition, U.S. natural gas consumption under *S7* decreases by 0.25 Bcf/day in 2050 compared to S6 (driven by domestic price increases in response to increased domestic production). Thus, the net increase in consumption globally in *S7* compared with *S6* is 1.37 Bcf/day. Compared to the total natural gas consumption globally in 2050 in *S6* (442 Bcf/day), this change is a <1% increase. Consequently, global primary energy consumption under *S7* does not change much compared to *S6*, as shown in Figure 7. Note that there is no change in global emissions under *S7* relative to *S6* since both scenarios are constrained to the same values by design.

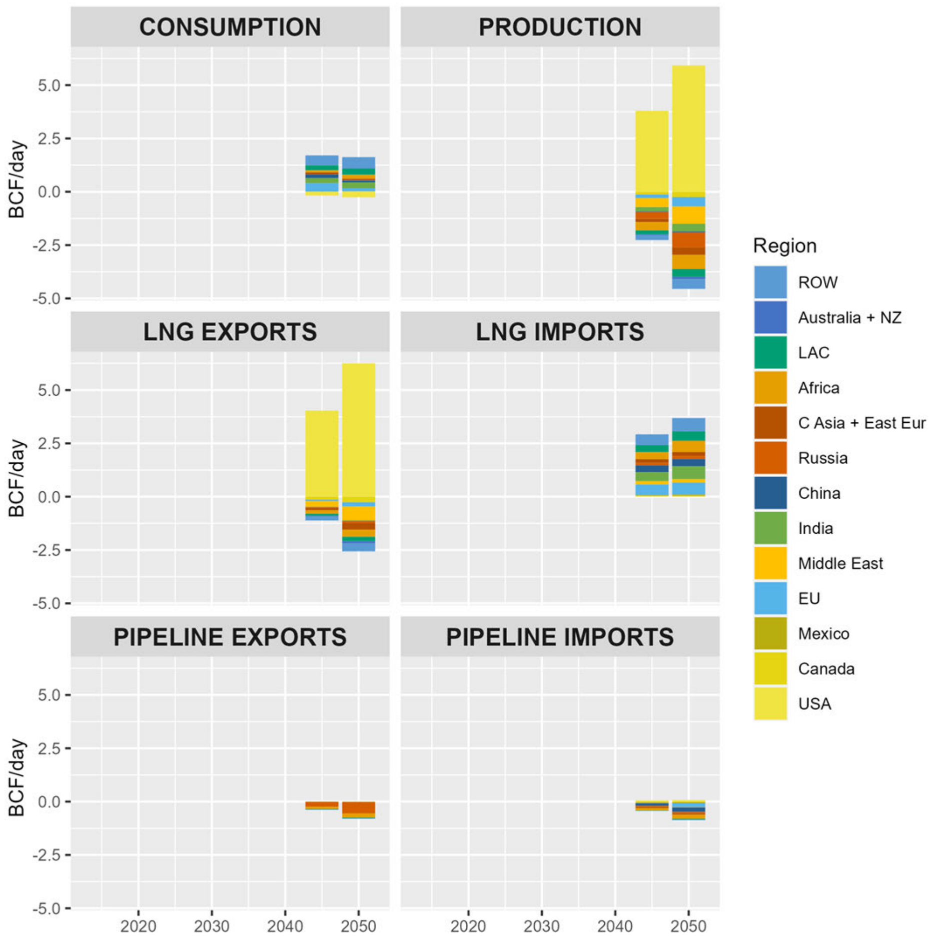


Figure 12. Changes in natural gas markets in S7 vs. S6. Conversion factors are as follows: 1 Tcf/yr = 2.74 Bcf/day and 1 Bcf/day = 0.36 Tcf/yr

E. Global Primary Energy Consumption and GHG Emissions Across All Scenarios

Overall, as shown in Figure 13, the seven scenarios explored in this study result in a range of outcomes for global primary energy consumption and emissions by 2050. Across *S1–S5*, global primary energy consumption in 2050 ranges 802–833 exajoules (EJ) and global emissions range 47.5–50.3 Gt CO_2e. In addition, the fuel composition of primary energy consumption and sectoral allocation of emissions are not very different across *S1–S5*. Total primary energy consumption and GHG emissions are highest under *S3,* driven by higher population growth and associated increases in energy demand.

Notably, total emissions in 2050 under *S1–S5* are relatively similar to 2015 levels because these scenarios include current policies and measures to deploy lower emission technologies. However, total primary energy consumption in 2050 under these scenarios is significantly higher compared to 2015, primarily driven by population and economic growth.

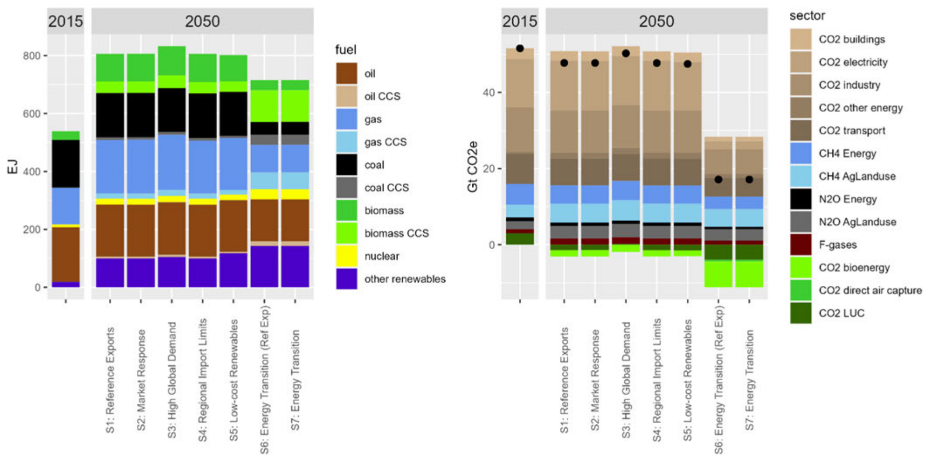


Figure 13. Primary energy consumption by fuel and GHG emissions by sector under all scenarios

By contrast, total energy and emissions are lowest under S6 and S7 due to assumptions about countries limiting emissions consistent with their pledges. Under these scenarios, global primary energy consumption in 2050 is 716 EJ and global GHG emission is 17 Gt CO_2e. As described earlier, these scenarios are also characterized by significant changes in the fuel composition of global energy consumption and the deployment of CDR technologies compared with S1–S5.

F. NEMS Analysis: Implications for U.S. Energy Systems

1. Energy Impacts

AEO2023-NEMS and FECM-NEMS were used to model U.S.-specific results for *S1–S5,* and *S6* and *S7*, respectively. Similar to global energy consumption, primary energy consumption in the United States grew over time in each scenario.

In 2025, the primary energy consumption was at approximately 103 EJ in scenarios *S1–S5,* as shown in Figure 14. By 2050, all scenarios saw an increase in total energy consumption, exceeding 110 EJ. The highest energy consumption was recorded in *S5* at 115 EJ, and the lowest consumption was in *S4* at 111 EJ.

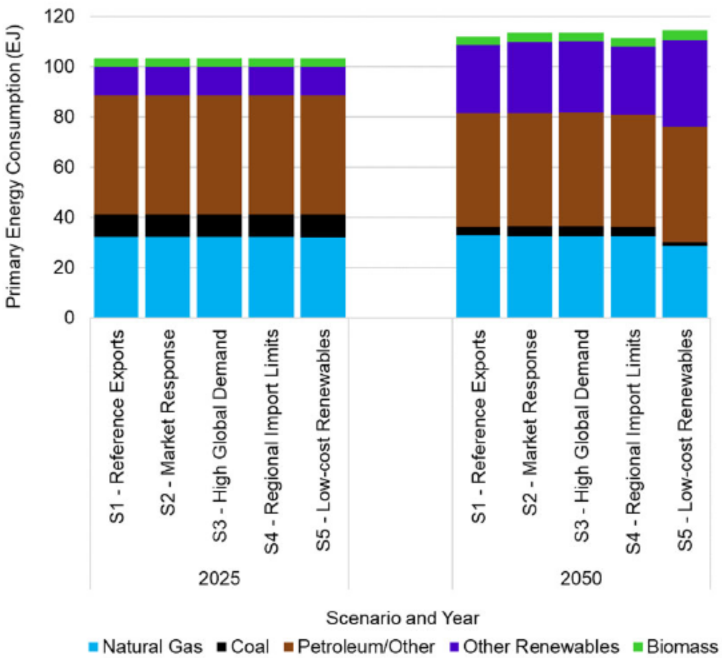


Figure 14. U.S. primary energy consumption, S1–S5

The availability of low-cost renewables in *S5* fosters the deployment of biomass and other renewable energy sources. A substantial decrease was noted in coal usage, with the most significant reduction occurring in *S5*. Natural gas consumption remained steady across *S1–S4*, hovering around 32.1–32.7 EJ, but experienced a decline to 28.6 EJ in *S5*.

Figure 15 shows U.S. primary energy consumption across *S6* and *S7* in 2025 and 2050. In 2025, U.S. primary energy consumption was predominantly driven by fossil fuels, which accounted for 85% of the total energy use. By 2050, energy consumption rose across both scenarios relative to 2025, and is distinguished by a notable increase in biomass and other renewables. Relative to *S6*, the increased LNG export trajectory in *S7* put pressure on the natural gas market, leading to more expensive GHG mitigation strategies by 2050 but ultimately a slight (0.8%) decrease in U.S. natural gas consumption. Biomass and other renewable sources grew by 23.6 and 23.3 EJ from 2025 to 2050 in the *S6* and *S7* scenarios, respectively, thereby contributing 32.1% of the total energy consumption in both scenarios. Natural gas consumption increased from 35.0 and 34.9 EJ in 2025 to 44.8 and 44.4 EJ in the energy transition scenarios *S6* and *S7*, respectively. Remaining primary energy, primarily petroleum, decreased across both scenarios from 47.7 EJ in 2025 to 36.2 EJ in *S6* and 35.8 EJ in *S7* by 2050.

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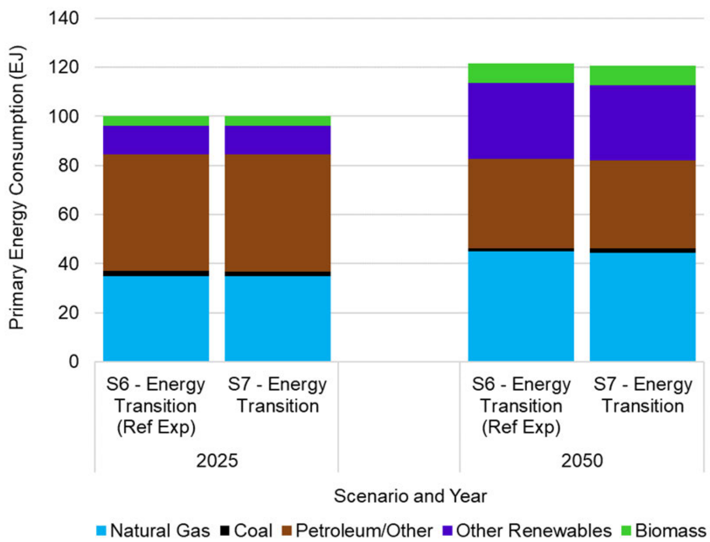

Figure 15. U.S. primary energy consumption S6 and S7

2. *Natural Gas Production and Consumption Impacts*

U.S. natural gas production increased across most scenarios to maintain projected export volumes. U.S. natural gas consumption, on the other hand, was relatively unchanged across the first four scenarios. Figure 16 plots total U.S. natural gas production, consumption, and export values over time. The LNG export values were identical to those plotted in Figure 3 and are included here as reference.

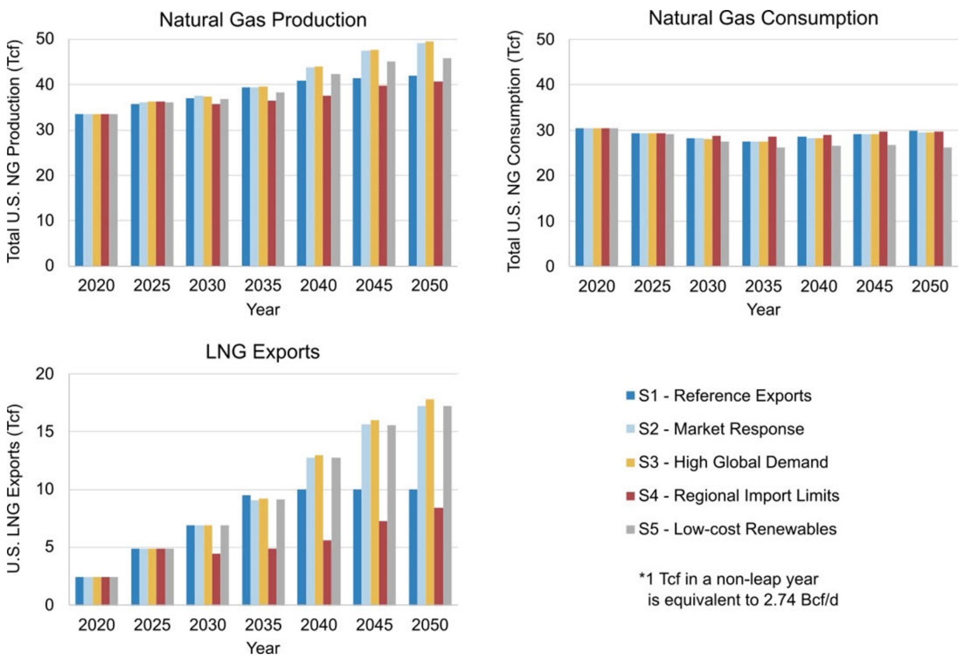

Figure 16. Total U.S. natural gas production, consumption, and export volumes over time, by scenario

From a starting point of 33.5 trillion cubic feet (Tcf)/day (91.5 Bcf/day) of natural gas production in 2020, production in each scenario increased, following a path that correlated with their LNG export curve. Natural gas production in *S1*, *S2*, and *S3* followed a similar trajectory by 2035, reaching 39.5, 39.4, and 39.5 Tcf, respectively. *S1* production then slowed through 2040 and reached a peak of 42.0 Tcf by 2050. *S2* and *S3* production values accelerated through 2050, reaching 49.0 Tcf and 49.5 Tcf, respectively. Similar to the trends in LNG exports, *S4* production exhibited the lowest values, ending slightly below *S1* at 40.7 Tcf in 2050. *S5* production exhibited the same general path as *S2* and *S3*, but grew more slowly, reaching 38.2 Tcf and 45.7 Tcf in 2035 and 2050.

The natural gas consumption volumes from *S1*–*S3* followed similar paths, dipping from 30.5 Tcf in 2020 to 27.6, 27.5, and 27.4 Tcf in 2035 before ramping up to 29.8, 29.6, and 29.6 Tcf in 2050 in these scenarios. Although *S4* had exhibited lower LNG export and natural gas production quantities, the consumption volumes in *S4* remained slightly higher than the volumes in *S1*–*S3* through most model years, equalizing with *S1*–*S3* in the final timestep. *S4* reported 28.5 Tcf of natural gas consumption in 2035 and 29.8 Tcf in 2050. *S5* was the largest outlier with the lowest consumption of 26.2 Tcf in 2035 and almost no change in consumption values between 2035 and remaining flat at 26.2 Tcf in 2050.

The lower natural gas production and consumption volumes in *S5* (when compared to *S2* and *S3*) are explained by the effect of low renewables costs on the energy system. *S5* adopted many of the same inputs as EIA's AEO2023-NEMS low zero-carbon technology cost scenario. These inputs drove down the cost of renewables and caused *S5* to switch from natural gas to cheaper renewable energy sources, affecting both production and consumption. The remaining scenarios showed similar levels of natural gas consumption, but different levels of natural gas production, suggesting that most increases in natural gas production were passing directly to LNG exports.

Figure 17 plots the natural gas production, consumption, and exports for the two net-zero scenarios. Natural gas production in *S6* and *S7* is 37.6 Tcf and 37.1 Tcf in 2035, respectively, but quickly rise to 54.7 Tcf and 56.5 Tcf by 2050. *S6* and *S7* exhibited a flatter trend in total consumption through 2040, but reached 41.9 Tcf and 41.5 Tcf, respectively, by 2050. The differences between the two net-zero scenarios were similar to differences observed in *S1*–*S5*: changes in production were correlated with changes in LNG exports, but differences in consumption between scenarios were minimal.

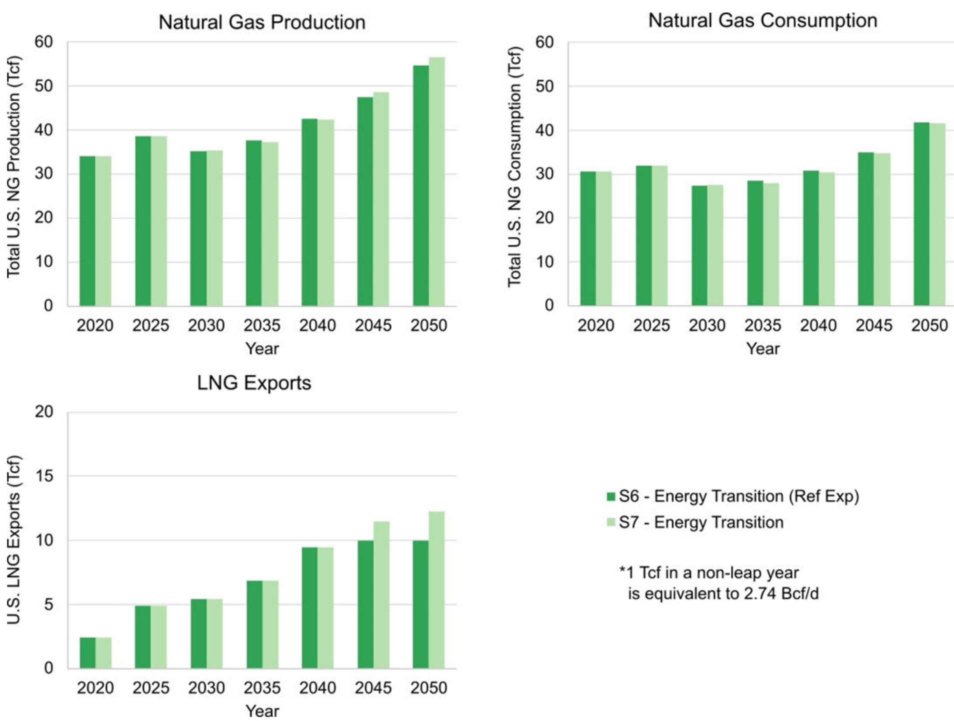

Figure 17. Total U.S. natural gas production, consumption, and export volumes, S6 and S7

The rapid increase in natural gas production and consumption for the net-zero scenarios after 2040 came from a substantial increase in natural gas to power DAC facilities, plotted in Figure B-5 in Appendix B: U.S. Analysis and Description of AEO2023-NEMS and FECM-NEMS. Natural gas consumption accounted for 16.8 Tcf and 16.2 Tcf in 2050 for *S6* and *S7*, respectively. More detail on CO_2 emissions and removals is provided in Section F, U.S. GHG Results.

3. Natural Gas Henry Hub Prices Impacts

Although total U.S. natural gas consumption volumes were similar across the first five scenarios, higher LNG exports increased natural gas prices by up to 33% in 2050. The natural gas price of the net-zero scenarios rose above the prices in *S1–S5*, driven mostly by demand for natural gas to power DAC facilities. Figure 18 plots the natural gas price at the Henry Hub in $2022/million cubic feet (Mcf) over time for all scenarios.

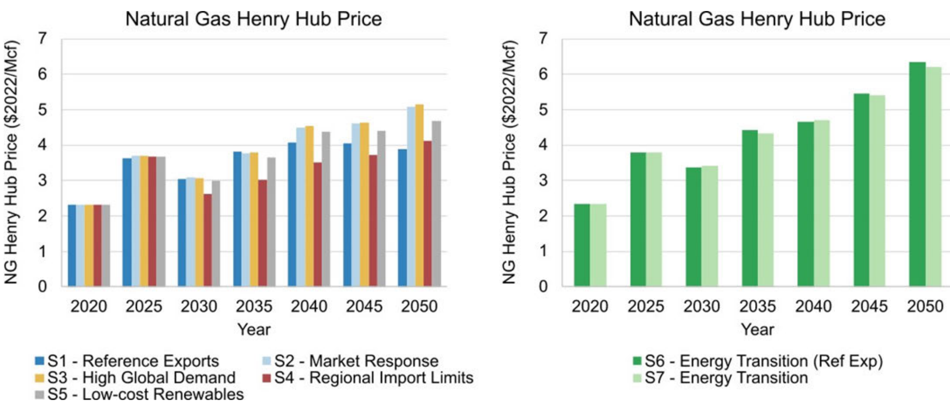

Figure 18. Total U.S. natural gas Henry Hub price by scenario ($2022)

The natural gas price in *S1* increased to a maximum of $4.08/Mcf in 2040 before moderating to $3.88/Mcf in 2050. The natural gas prices in *S2*, *S3*, and *S5* were mostly consistent with *S1* through 2035 but ultimately rose to levels of $5.09/Mcf, $5.15/Mcf, and $4.67/Mcf, respectively, by 2050. The difference in prices correlated with the differences in LNG export curves, while LNG exports in *S1* plateaued after 2035 and saw a drop in natural gas prices. *S2*, *S3*, and *S5* all exhibited both increasing exports and prices. *S4* had lower natural gas prices over most of the modeling period but ultimately exceeded *S1* in 2050 with a price of $4.12/Mcf; the persistent increase in *S4* prices after 2030 was consistent with increases in LNG exports throughout the same period.

The influence of LNG exports on natural gas prices shown in Figure 18 was similar to the effect reported in EIA's May 2023 "Issues in Focus" report on LNG.[26] EIA's "Fast Builds Plus High LNG Price" scenario, which modeled the effect on U.S. energy markets of accelerated construction of LNG infrastructure in an environment with elevated international demand for LNG, reported a 2050 natural gas price of $4.81/million British thermal units (MMBtu) (equal to $4.98/Mcf) at 48.2 Bcf/day of exports. These values are close to the results from *S2* of $5.09/Mcf at 47.2 Bcf/day of exports and demonstrate agreement between the two studies on the relationship between LNG exports and natural gas prices.

Overall U.S. natural gas consumption did not change appreciably in response to higher prices, but there were some shifts in consumption behavior on a sector-by-sector basis. These sector-specific differences

[26] U.S. EIA (2023). AEO2023 Issues in Focus: Effects of Liquefied Natural Gas Exports on the U.S. Natural Gas Market. Available at: https://www.eia.gov/outlooks/aeo/IIF_LNG/pdf/LNG_Issue_in_Focus.pdf.

are presented in greater detail in Figure B-3 in Appendix B: U.S. Analysis and Description of AEO2023-NEMS and FECM-NEMS.

The natural gas price of *S6* and *S7* rose above the prices in *S1–S5*, driven mostly by demand for natural gas to power DAC facilities. Natural gas prices for S6 and S7 were similar to prices in *S1* through 2030, but afterwards rapidly increased on a trajectory consistent with the growth of DAC. *S6* and *S7* reached prices of $6.34/Mcf and $6.20/Mcf, respectively, by 2050. The difference in price between *S6* and *S7* was within the tolerance of the model.

4. *U.S. Macroeconomic Outcomes*

While NEMS has rich detail about the energy system, a separate Macroeconomic Activity Module (MAM) provides projections of economic drivers underpinning NEMS' energy supply, demand, and conversion modules. The MAM incorporates IHS Markit's (now S&P Global's) model of the U.S. economy, along with EIA's extensions of industrial output, employment, and models of regional economies. The S&P Global module is modified to include EIA's key assumptions, such as world oil price, and yielding a baseline trajectory of the economy. The baseline cannot appropriately respond to the wider economic changes in the net-zero scenarios, so such analysis is not included here. Within a NEMS scenario, feedback from the other NEMS modules includes the following:

- Production of energy, including coal, natural gas, petroleum, biomass, and other fuels
- Trade in energy, including net exports coal, petroleum, natural gas, and biofuels
- Total and end-use demand for energy, including sales of electricity
- Consumer spending on energy, disaggregated to fuel oil motor fuels, electricity, natural gas, and highway consumption of gasoline
- Energy prices including a price index for consumer prices and wholesale prices
- Industrial production indices for oil and gas extraction and coal mining

Since the MAM does not track individual projects, GDP estimates do not include economic activity associated with specific export facilities and, thus, the impacts are approximate.

GDP estimates in NEMS are only loosely coupled with the energy market representation and, therefore, there is some uncertainty in the GDP metric. In addition, because NEMS is a domestic model, trade effects are not represented in as granular a level as domestic energy markets. One result is that modeled GDP growth is in general inversely proportional to the growth in natural gas prices and uncertainty increases as the forecast horizon increases. With those caveats, Figure 19 shows U.S. GDP growth across scenarios. The growth rate through 2045 remained essentially constant across all five scenarios, increasing at 1.9% annually. Higher natural gas exports caused natural gas prices to rise by up to 33% in 2050, reducing economic activity in some sectors but increasing in others. The impact of increased LNG exports was positive on GDP by less than 0.1% across scenarios the through 2045. Accelerating natural gas prices in the last five years of the projection period in *S2* reduced consumption of other products and tended to slightly reduce the overall rate of economic growth relative to *S1*. Overall, GDP changes in 2050 relative to 2020 were within 0.3%: $42.4 in S1 versus $42.3 in *S2–S5*.

Commented [WS120]: A few points:
1. This data should be presented in numbers as well as visually.
2. We state that higher exports is positive on GDP until 2050, but S1 seems greater than S2 throughout the entire time series.
3. Does the last sentence mean we think that 0.3% of GDP is a small amount that doesn't warrant further discussion? 0.3% of 42 trillion is over 100 billion. Are we saying that incremental exports of 20 Bcf/d would reduce the size of the US economy by that amount? Over $5b per Bcf/d? If so that seems like a very consequential finding and one that should be explored in greater depth.
A few points:
1. This data should be presented in numbers as well as visually.
2. We state that higher exports is positive on GDP until 2050, but S1 seems greater than S2 throughout the entire time series.
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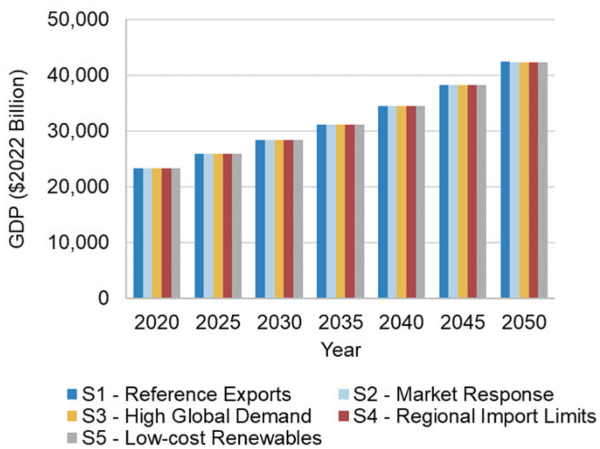

Figure 19. U.S. real GDP changes

Figure 20 shows the residential natural gas price in each of the five key scenarios. In 2050, natural gas prices in *S3* (when exports are the highest) were 4% higher than *S1*, when exports were the lowest. Overall, natural gas price differences between the scenarios were generally close to 1–2% across the scenarios.

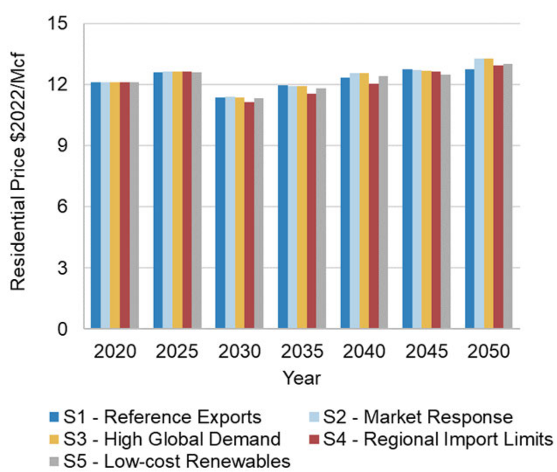

Figure 20. U.S. residential natural gas prices

One component of GDP tracked by NEMS is the value of industrial shipments, shown in Figure 21. Industrial processes are sensitive to natural gas prices, which were generally higher than *S1*. However, increased production, processing, and transportation of natural gas requires additional equipment, which tends to increase industrial shipments. Overall, NEMS showed a very slight increase in the value of industrial shipments in *S2* relative to *S1* of 0.2% in 2050. The value declined in *S4* versus *S1*, reflecting lower natural gas production and exports.

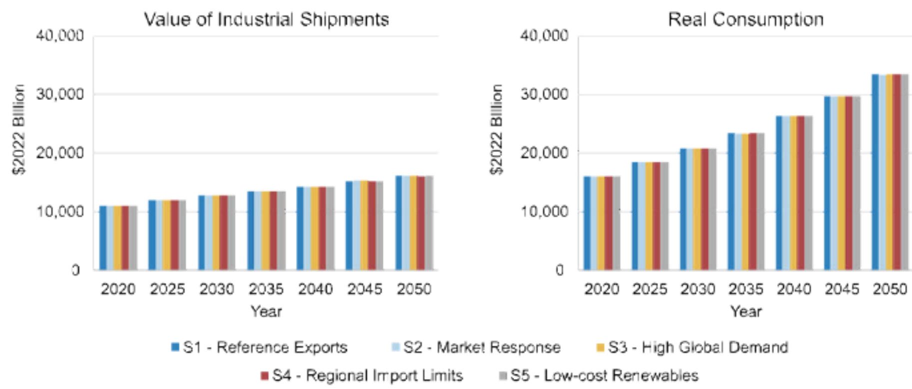

Figure 21. U.S. value of industrial shipments and real consumption

The NEMS analysis shows LNG exports could benefit consumers through increased labor income and the return on capital expen~~ded~~~~des~~ on facilities to produce and export the commodity. Exports increased the value of the dollar, decreasing the cost of some imports. However, increased demand for natural gas, including exports, raised the price of natural gas and the costs of products that require natural gas as an input. This can be observed in the change in aggregate consumption, which is another component of GDP. When energy prices rise, consumers must pay more for natural gas, but purchases of other goods decrease. Across all the scenarios, the effect on natural gas prices was small, and, while wealth transfers may occur between consumers as some groups benefit more than others through increased production, this was not reflected in the aggregate output of the model. Changes across all the scenarios were essentially flat. Overall, by 2050 consumption changes were less than 0.2%.

In a fully competitive market, the delivered price of LNG should be sufficient to fully accommodate the cost of production, liquefaction, and transportation of natural gas. Since much of this activity occurs domestically, it is a rough proxy for economic activity engendered by LNG exports. A representative price would be the price of imports to the EU. Figure 22 shows estimates of export revenues as the product of the LNG export volumes and the EU LNG price.

Commented [UP121]: Should this be LNG instead of NG? or does the NEMS analysis show benefits of all NG exports? We've been discussing LNG exports so far in the report so just checking?

Commented [DH122R121]: Yes apologies, this should be LNG. Edited.

Commented [JG123]: @Daniel Hatchell - expends?

Commented [DH124R123]: @Jasmine Greene I think this was meant to say expenses - @Peter Whitman does this look correct?

Commented [DH125R123]: Updated to "expended"

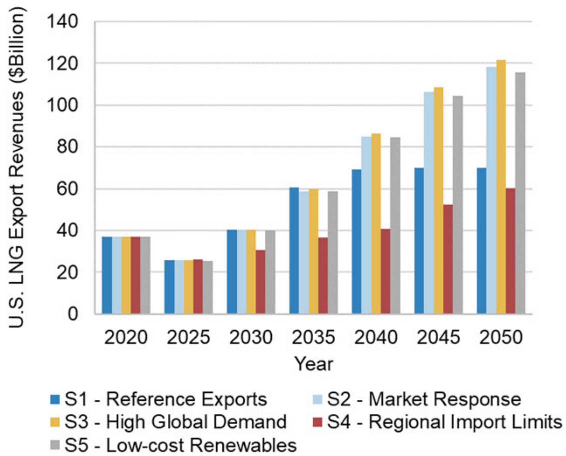

Figure 22. U.S. LNG export revenues

5. U.S. GHG Results

AEO2023-NEMS tracks CO_2 emissions from the combustion and use of fossil fuels. These CO_2 emissions did not change significantly among scenarios in response to varying LNG export levels. Figure 23 plots CO_2 emissions from fossil fuels for *S1–S5*.

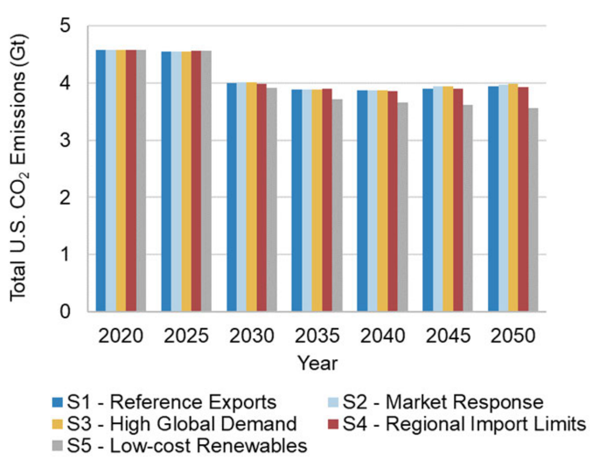

Figure 23. Total U.S. CO_2 emissions from fossil fuel combustion

From a starting point of 4.58 Gt CO_2 emissions in the United States in 2020, the first four scenarios declined to 3.99–4.02 Gt CO_2 in 2030 and followed a flatter trajectory to 3.93–3.98 Gt CO_2 in 2050. There was a weak connection between LNG exports and CO_2 emissions: scenarios with the highest exports (*S2* and *S3*) had slightly higher CO_2 emissions levels in 2050 of 3.97 and 3.98 Gt, respectively, whereas scenarios with lower exports (*S1* and *S4*) reported respective CO_2 emissions of 3.94 and 3.93 Gt. The relationship was small, however, and accounted for only a 1% difference in emissions. The small differences between the first four scenarios were consistent with the relatively unchanged natural gas consumption volumes observed in Figure 16. *S5* was an outlier, continuing to decrease through 2030 (3.91 Gt CO_2) and reaching 3.57 Gt CO_2 emissions by 2050. The lower emissions from *S5* were explained by the assumptions used for low renewable costs rather than by changes in LNG exports.

Commented [WS126]: Should these be 3940 and 3930?

Commented [DH127R126]: Yes, thanks for catching that - updated to be 3.94 and 3.93 Gt CO2

S6 and *S7* were modeled in FECM-NEMS, which endogenously calculated some additional emissions that AEO2023-NEMS is missing (most relevant being CH_4 leakage from natural gas production and processing infrastructure). To retain consistency between the two models, only the CO_2 emissions reported by FECM-NEMS were included in the analysis and used to define the net-zero GHG scenarios. The remaining non-CO_2 emissions (which still contributed to the overall net-zero GHG cap) were calculated endogenously within GCAM and used in FECM-NEMS as an exogenous input.

Figure 24 plots the CO_2 emissions and removals for *S6* and *S7*. Both scenarios had both lower emissions than *S1* and significant amounts of CO_2 removals, reaching net-zero by 2050.

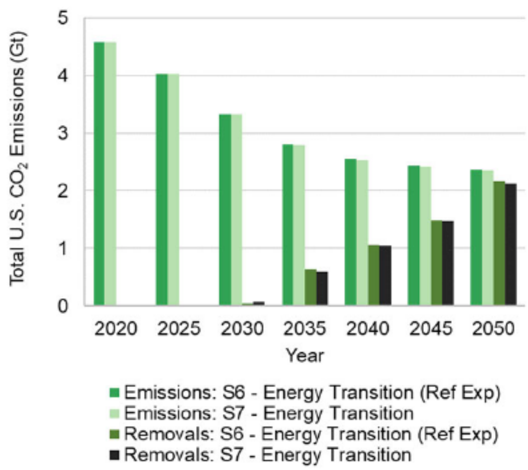

Figure 24. Total U.S. CO_2 emissions from fossil fuel combustion and removals, S6 and S7

CO_2 emissions from *S6* and *S7* began at 4.58 Gt and declined continuously through 2050, ending at 2.37 and 2.35 Gt CO_2, respectively. These declines were primarily driven by electrification of broad sections of the economy with a combination of renewables and CCS. The decline in emissions was accompanied by an increase in removals, which started growing rapidly in 2030 and eventually reached 2.16 Gt CO_2 for *S6* and 2.13 Gt CO_2 for *S7* in 2050. The majority of removals (87–89% by 2050) came from DAC, with the remainder coming from H_2 production with biomass and BECCS. The specific breakdown of removal technologies is explored in Appendix B: U.S. Analysis and Description of AEO2023-NEMS and FECM-NEMS, Section C. While the removals did not completely counterbalance the 2.35–2.37 Gt of CO_2

Commented [HH128]: Correct? There is no Section D in Appendix B.

emissions, the difference is offset by the sum of the changes in land-use and non-CO_2 emissions calculated within GCAM and used as exogenous inputs, which were net negative.

Commented [PW129]: Added land-use

G. NETL LCA

The goals of the LCA component of this project were twofold: first, to help contextualize how the other results of this study (i.e., NEMS and GCAM) connect to past studies of U.S. natural gas and LNG operations and, second, to leverage the results of the other models to quantitatively represent the international GWP consequences from changes in quantities of U.S. exported LNG.

In support of the first goal, the following work was completed:

- Assessed whether NEMS results suggested significant changes in domestic supply (resulting in potential future upstream GWP intensity or emissions changes).
- Compared and aligned GCAM and NETL results to create a representation of the global natural gas supply chain that is consistent with existing NETL natural gas LCA studies.

Commented [AA130]: Delete or "that is"

In support of the second goal, the following work was completed:

- Developed a quantitative MAF that represents the consequences of additional export volumes of U.S. LNG, such as how additional available quantities of natural gas led to changes in the energy sectors of countries that purchase the LNG. These consequential effects were estimated by tracking differences in global GHG emissions and quantities of U.S. LNG exported from the GCAM scenarios and assessed in comparison to existing NETL quantitative estimates of the upstream natural gas production.

In this project, NEMS and GCAM sought to represent economic and environmental changes associated with the defined changes in U.S. LNG exports. GCAM estimated global GHG emissions effects, including emissions associated with upstream natural gas. To compare the GCAM results with the NETL LCA work used by DOE in support of natural gas and LNG export decisions, NETL assessed and aligned the emissions estimates per unit of gas produced and delivered to large end users (e.g., LNG export facilities) in the United States of GCAM and NEMS to the NETL life cycle GHG intensity for U.S. average natural gas production and delivery to large end users using the ratio of the NETL and GCAM results. Non-U.S. region natural gas production and delivery GHG emissions intensity values were also adjusted to align with NETL life cycle GHG intensity values based on the same ratio of U.S. values. This process was conducted for all years and regions reported by GCAM.

Commented [ST131]: Results were not aligned to the past NETL work on LNG exports. Work was aligned to the current NETL 2020 natutal gas upstream thru transmission to a large end user U.S. average GHG emissions per unit of natual gas delivered.

Commented [SM132R131]: Agreed, edited (slightly modified the suggested revision).

1. *Assessment of NEMS Domestic Natural Gas Production by Region*

NEMS modeling focused on domestic changes that would be expected to occur in the seven scenarios modeled. NETL evaluated the regional sources of natural gas using outputs from NEMS to compare them to the mix of regions NETL uses in existing assessments of upstream natural gas emissions.

As shown in e, the NEMS results suggested only modest changes in the production mix by region and, thus, would not be expected to substantially change the domestic average GHG intensity per MJ of natural gas produced compared to previous analyses. As such, no regional adjustments were made to the U.S. results.

Commented [AA133]: Spell out if first time using this unit alone.

Commented [SM134R133]: Defined earlier, and added to glossary, thanks!

2. *Comparison of GCAM and NETL Estimates of GHG Emissions of the Natural Gas Sector*

As discussed above, GCAM represents economic activity (and associated GHG emissions) by sectors and technologies, and their respective inputs and outputs, for regions, years, and scenarios. However, only a subset of these was relevant to the scope of the natural gas LCA-focused effort.

Only three sectors in GCAM include GHG emissions of the natural gas sector: ***natural gas***, ***gas pipeline***, and *other industrial energy use* (see Appendix C: Supporting LCA for more detail). Using the basis of process stages as represented in the NETL Natural Gas model, Figure 25 shows the relevant GCAM sectors that have associated CO_2 and non-CO_2 emissions. While, overall, GCAM 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 were represented.

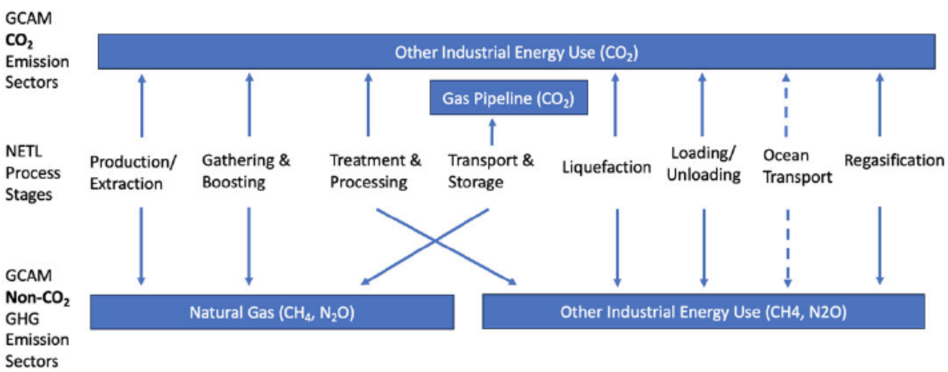

Figure 25. Mapping of NETL natural gas stages to GCAM sectors

As summarized in Figure 25, all stages of the NETL LCA are explicitly represented in GCAM except for Ocean Transport, which was included as part of other industrial energy use but could not be separated out for this analysis. As a result, the comparison in this report was focused on a comparison of emissions from production of natural gas in the United States through delivery to a large end user rather than LNG delivered around the world.

Quantitative values of emissions intensities in the year 2020 of the various GCAM sectors for the "USA" region for the three natural gas-relevant sectors are listed and compared to NETL natural gas model results in Appendix C: Supporting LCA. Note, in order to compare NETL and GCAM results, NETL model results were regenerated using LHV basis as shown below and differ from those published (as HHV by default) in the report.

Overall, the estimated upstream emissions for the USA region in GCAM in the year 2020 for *S1* were about 8.52 g CO_2e/MJ (AR6-100, LHV basis), which is slightly higher than those of the NETL model for the boundary of production through transmission to large end user (8.18 g CO_2e/MJ, LHV basis). Using the relationship between those estimates, emissions results in the three GCAM natural gas sectors were adjusted by a factor of 8.18/8.52, or 0.96 (a 4% reduction) to maintain consistency with past NETL studies of the natural gas sector. This adjustment factor was used for all regions and for all years in the

Commented [ST135]: Labels in "blue" boxes need capitalized.

Subscript the 2 and 4 in CO2, CH4, and N2O.

NETL Process Stage labels should be centered with the arrows.

Commented [SM136R135]: Fixed.

Commented [HH137R135]: CH4 and N2O in the bottom right-hand blue box still need to be superscripted.

Commented [ST138]: The rest of the report uses "U.S." instead of "USA".

Commented [SM139R138]: Just referring to the actual region name here

Commented [ST140]: See previous comment, this numeric values used need to be stated.

Commented [SM141R140]: Added

Commented [ST142]: Is the GCAM value consistent over the 35 year time horizon?

Is this the levelized average over 35 years that includes performance improvements within GCAM? Or is it the year 2020 value?

Are the values different for S7/S6 when climate pledges and net zero are considered? How did this effect the MAF calculation when considering temporal and economic variability?

Commented [ST143R142]: Need to state that the 8.52 is **the year 2020 GHG emissions intensity.**

Added to text - please confirm edit.

After reading the report, I don't think the value is levelized over 35 years. Unclear how GCAM GHG intensity per unit of LNG changes over time within the GCAM model (or NEMS).

Commented [SM144R142]: We apply the same adjustment factor through all the years, for all regions. This maintains the built-in methane mitigation curves in GCAM.

Commented [WS145]: If we used the GCAM estimate, how would that affect our GHG projections? Some will argue that we cherry picked a more favorable estimate, so it would be helpful to say that our conclusions are robust to that assumption.

model. Similar adjustment factors were found for IPCC AR6 20-year (AR6-20) and IPCC Fifth Assessment Report (AR5) 100-year and 20-year bases (AR5-100 and AR5-20, respectively) (see Appendix C: Supporting LCA for further details). The results are similar whether using the adjusted or unadjusted values.

For context, in the GCAM results for *S1* in year 2020, total global GHG emissions are approximately 53,000 teragrams (Tg). The NETL adjustment post-processing of the GCAM results on the AR6-100 basis of the GCAM *gas pipeline* and *natural gas* sectors reduces emissions by about -7 and -35 Tg CO_2e, respectively, when considering those of *S1* in the Year 2020. Post-processing adjustments of the GCAM results of the *other industrial energy use* sector reduce emissions by about -10 Tg CO_2e when considering those of S1 in year 2020. The adjustments for these three sectors needed to align with past NETL studies and have the cumulative effect of reducing estimated emissions from GCAM by about 0.2% (in *S1* in year 2020).

This same process was undertaken for different IPCC GWP values, and the resulting alignment tables and adjustment factors are provided in Appendix C: Supporting LCA.

3. *Market Adjustment Factor Results*

MAFs quantitatively estimate the consequential effect on global emissions as a function of U.S. LNG exported. MAFs for *S2* were estimated versus a baseline of *S1*, while the MAF for *S7* was estimated versus a baseline of *S6* given the significantly different global economy modeled in these scenarios.

MAFs were calculated using the post-processed LHV NETL-adjusted GCAM results described previously as well as the unadjusted GCAM results (HHV results are shown in Appendix C: Supporting LCA). The MAF was calculated for each scenario by aggregate annual values over the time horizon of the model (i.e., the MAF for *S2* versus *S1* was defined as 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 same period).

All MAFs were found using a variety of IPCC Assessment Report GWP values over 20- and 100-year time horizons, and with the raw and post-processed NETL adjusted GCAM results. MAF results from AR6-100 are presented, and results for other IPCC Assessment Report and time horizons (and all raw GCAM results) are shown in Appendix C: Supporting LCA.

Table 4 shows the MAFs for *S2* (versus *S1*), which varied from -5.34 to -5.35 g CO_2e/MJ on a 100-year time horizon (LHV basis) or -5.37 (HHV basis). Also included is a summary reminder of the differences in the modeled scenarios (e.g., where *S1* is the baseline and *S2* added an economic solution for LNG exports, making a direct comparison of the two appropriate).

Table 4. MAFs for S2 vs. S1 (IPCC AR6-100)

	Results (g CO_2e/MJ)			
MAF Case	GCAM (LHV)	GCAM with LHV Adjustment	GCAM with HHV Adjustment	Scenario Difference
S2* vs. *S1	-5.34	-5.35	-5.37	Adds economic solution for LNG exports.

Commented [ST146]: Why the italicized label? Not italicized in other parts of the report?

Commented [SM147R146]: Fixed, meant to only italicize sector names

Commented [ST148]: All results need to be on a HHV basis to document what will actually be used by NETL when added to the attributional results.

I am okay with report comparing to GCAM in LHV, however, that is not the result that needs documented for use in future export analyses that include consequential market effects. This report needs to document the values that will be used in future work.

Commented [SM149R148]: Will add HHV values to Appendix.

Commented [ST150]: Add HHV results.

Table 5 shows market adjustment factors for *S7* versus *S6*, both of which represented significantly different energy and economic investments in support of a low-carbon economy through climate policies. The *S7* MAFs vary from -2.95 to -3.01 on a 100-year time horizon (LHV basis) or -2.81 (HHV basis).

Table 5. MAFs for S7 vs. S6 (IPCC AR6-100)

Results (g CO_2e/MJ, LHV)				
MAF Case	**GCAM (LHV)**	**GCAM with LHV NETL Adjustment**	**GCAM with HHV NETL Adjustment**	**Scenario Difference**
S7* vs. *S6	-3.01	-2.95	-2.81	S6 1.5°C pathway, economic solution for LNG exports

4. *Interpretation of Global Market Adjustment Factor Results*

On an AR6-100 basis, for *S2–S1*, the MAF result was approximately -5.4 g CO_2e/MJ (LHV). For purposes of comparison, NETL estimated natural gas upstream emissions prior to delivery to a large industrial end user (like an LNG terminal) are 8.18 g CO_2e/MJ (LHV), equivalent to 7.44 g CO_2e/MJ (HHV). The MAF indicates that as U.S. LNG exports increased, the induced global market effects would result in an overall reduction in GHG emissions that is about 65% of the estimated upstream emissions associated with production through delivery of the natural gas to a large industrial end user in the United States.

As noted in Appendix C: Supporting LCA, Section e, Market Adjustment Factors for Other IPCC GWP Values, the NETL Natural Gas model estimated life cycle GHG emissions associated with delivery of U.S. LNG to a regasification facility in Europe to be 20 CO_2e/MJ (AR6-100, LHV basis) and 18.1 CO_2e/MJ (HHV basis). Thus on a life cycle basis and considering cumulatively through 2050, the induced global market effects per unit of increased LNG exports are equivalent to an overall reduction in GHG emissions that is about 27% of the estimated emissions associated with U.S. LNG delivered to Europe under reference climate policy assumptions (LHV basis, 30% on HHV basis) and 15% of the estimated emissions associated with U.S. LNG delivered to Europe under global decarbonization policy assumptions (LHV basis, 16% on HHV basis).

These results are consistent with the idea that as the global economy decarbonizes, the induced global decarbonization benefit of increased U.S. LNG will be less. Overall, both of these results were consistent with the overall GCAM results that showed increased U.S. exports did not lead to increased global GHG emissions. Global changes in GHG emissions were constant to slightly negative as U.S. natural gas exports increased and global energy demand increased. The GHG reductions represented by the negative MAF were not so large that U.S. LNG should be regarded as a global climate reduction strategy but, at the same time, a negative MAF suggested that increased U.S. LNG exports could be compatible with global decarbonization efforts. A positive MAF would suggest U.S. LNG was leading to overall increased global emissions. The results were aggregated in relation to estimated future volumes of exported LNG from the United States 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 natural gas sources would directly lead to lower GHG emissions results when supplied around the world.

Commented [ST151]: Add HHV results.

Commented [TC152]: For the leadership briefing, Tim recalculated this interpretation as follows. Can you confirm these calculations and change the section to reflect this interpretation? (Tim also has the calculations in a comment below).

On a life cycle basis through 2050, the induced global market effects per unit of increased LNG exports are equivalent to an **overall reduction in GHG emissions** that is about:
27% of the estimated emissions associated with U.S. LNG delivered to Europe **under reference climate policy assumptions** (LHV basis, 24% on HHV basis)
15% of the estimated emissions associated with U.S. LNG delivered to Europe **under global decarbonization policy assumptions** (LHV basis, 15% on HHV basis)

Commented [ST153]: Reported as 7.44 previously in the report.

Commented [ST154]: I calculate a 66% reduction. 70% is generous rounding.

Commented [WS155]: (b)(5) [redacted]

(b)(5) [redacted]

Commented [ST156]: Results need to be also reported in context of delivered LNG to provide a more complete perspective on the actual magnitude of percent change in delivered LNG cargo.

I understand that distance, and their emissions, from

Commented [ST157]: Add: result through delivered LNG.

E.g.

7.44 g HHV, equals 8.18 g LHV

Commented [LBD158]: It's not completely clear to me why this comparison is made - it seems like there is a projected reduction in GHG emissions from S1 to S2, but it's small? A global reduction equal to 70% of the LC emissions of one large industrial user? If that's correct, it might be clearer to just present the

CONCLUSIONS

The purpose of this study was to examine the potential global and U.S. energy system and GHG emissions implications of a wide range of economic levels of U.S. LNG exports. The study comprises three coordinated analyses: 1) a **Global Analysis** to explore a wide range of scenarios of U.S. LNG exports under alternative assumptions about future population and economic growth, regional preferences for domestically produced natural gas, pace of technological change in competing technologies (e.g., renewables), and countries' announced GHG emissions pledges and policies; 2) a **U.S. Domestic Analysis** of the implications of the various U.S. LNG export levels derived from the Global Analysis for the supply and demand of natural gas within the United States and the U.S. economy; and 3) an **LCA** to examine the life cycle emissions implications of the various levels of U.S. LNG exports derived from the Domestic and Global analyses. A number of key insights from this study are summarized below. Table 6 provides a data summary of the results across scenarios.

1. Across all modeled scenarios, U.S. LNG exports continue to grow beyond current operational export capacity (14.3 Bcf/day) through 2050. In addition, U.S. natural gas production grows beyond current levels through 2050. Across all the scenarios, LNG exports range 23–49 Bcf/day. The range of U.S. LNG exports from this study is consistent with EIA's analysis (15–48 Bcf/day).[27] Compared to *S1*, growing to 27.3 Bcf/day by 2050, *S2* results in significant growth in U.S. LNG exports to 47 Bcf/day by 2050. The availability of additional U.S. natural gas at competitive prices in the global natural gas market in *S2* results in a reduction in production, reduction in LNG exports, increase in LNG imports, and reduction in pipeline trade outside of the United States.
2. Global natural gas consumption increases by <1% under *S2* compared to *S1*, resulting in a shift in the regional composition of natural gas production and trade. The majority of U.S. natural gas substitutes for other global sources of natural gas.
3. U.S. natural gas prices as measured at the Henry Hub increase when comparing *S2* to *S1*. Across those scenarios, 2050 Henry Hub prices are projected to increase from \$3.88/Mcf to \$5.09/Mcf, both of which are less than the reference 2050 price expected in the most recent study DOE[Error! Bookmark not defined.] commissioned on the economic impacts from U.S. LNG exports in 2018.
4. U.S. residential prices are projected to be 4% higher in 2050 when comparing *S2* to *S1*. The change in residential prices did not exceed 4% in any of the scenarios and the percentage difference was generally substantially less.
5. The value of industrial shipments remains essentially unchanged (increasing less than 0.1% by 2050) when comparing *S2* to the *S1*. The impact of increased LNG exports on GDP is essentially flat, positive by less than 0.1% across scenarios through 2045 while all changes are within 0.3% in 2050.
6. Even though U.S. LNG exports continue to grow beyond existing and planned nameplate capacity across scenarios *S1*–*S5* to 23–49 Bcf/day by 2050, global and U.S. GHG emissions do not change appreciably. Global emissions in these scenarios range 47.5–50.3 Gt CO_2e and U.S. emissions range 4.3–4.6 Gt CO_2e across these scenarios.

[27] U.S. EIA. (2023). Issues in Focus: Effects of Liquefied Natural Gas Exports on the U.S. Natural Gas. Available at: Markethttps://www.eia.gov/outlooks/aeo/IIF_LNG/

Commented [UP159]: Shouldn't this be 49 Bcf/d based on S3 scenario (see page 21)?

Commented [IGC160R159]: Yes. Thanks.

Commented [UP161]: Here we're using 1-digit 27.3 Bcf/d versus 27.34 Bcf/d in earlier tables. I prefer 1-digit but we should be consistent with the decimal for the AEO 2023 forecast of LNG exports.

Commented [AA162]: Recommend adding clarifying language. Note description used early makes it clear that the reduction in production/export was from "other parts of the world." See:

Under *S2*, U.S. LNG exports grew to ~47 Bcf/day by 2050. In this scenario, the availability of additional U.S. natural gas in the global natural gas market at competitive prices resulted in a reduction in production and LNG exports from other parts of the world. The increased availability of U.S. LNG in the global market also resulted in higher LNG imports and reduced pipeline trade outside of the U.S.

Commented [IGC163R162]: The sentence includes "outside of the U.S." at the end.

Commented [LBD164]: Hard to describe as a "modest" increase, if in constant dollars. The increase is almost 1/3.

Commented [HH165R164]: This was deleted in the Ex Sum, so I've deleted it here.

Commented [LBD166]: This point was not included in the summary of findings in the Ex Sum.

Commented [WS167]: As noted above, this statement needs further explanation.

Commented [UP168]: Number check? 49?

7. The induced global market effects of a case that reflects reference climate policies are equivalent to an overall reduction in GHG emissions of about 27% of the estimated upstream emissions associated with production through delivery of the natural gas to an LNG regasification facility in Europe. Such induced market effects in a case representing future global decarbonization policies are equivalent to an overall reduction of 16%.
8. When compared to the other scenarios, *S6* and *S7*—in which countries are assumed to achieve their GHG emissions pledges and pursue ambitious GHG mitigation policies consistent with limiting global warming to 1.5°C—are characterized by a global transition resulting in lower in natural gas, coal, and oil consumption without CCUS; higher deployment of gas, coal and biomass with CCUS, and renewables; higher deployment of CDR strategies; and lower overall energy consumption. In *S6*, U.S. LNG exports are limited to the values from *S1* (by design) and grow to 27.3 Bcf/day by 2050. *S7* assumes economically driven outcomes resulting in U.S. LNG exports growing to 34 Bcf/day by 2050. The higher growth in U.S. LNG exports in *S7* compared to *S6* is driven by increased global demand for natural gas with CCUS in the power and industrial sectors. Similar to the comparison between *S1* and *S2*, the availability of additional U.S. LNG in *S7* in the global natural gas market results in a reduction in production, reduction in LNG exports, increase in LNG imports, and reduction in pipeline trade in the rest of the world compared to *S6*. In addition, global natural gas consumption increases by <1% under *S7* compared to *S6*. Furthermore, with the higher U.S. LNG exports in *S7* compared to *S6*, U.S. natural gas prices are essentially unchanged within modeling tolerance, reaching $6.34/Mcf in *S6* and $6.20/Mcf in *S7* by 2050.

Table 6. Key U.S. and global results in 2050 across scenarios

Scenarios	U.S. LNG Exports (Bcf/d)	U.S. NG Henry Hub Price ($2022/Mcf)	U.S. Net GHG Emissions (Gt CO_2e)	Global Net GHG Emissions (Gt CO_2e)
S1	27.3	$3.88	4.5	47.7
S2–S5	23.1–48.7	$4.12–5.15	4.3–4.6	47.5–50.3
S6–S7	27.3–33.6	$6.20–6.34	0	17.1

Commented [ST169]: Consider splitting the conclusions into two parts: S1/S2 and S6/S7 to improve clarity.

Commented [IGC170R169]: This bullet focuses on S6-S7 only.

Commented [ST171]: Did we run another set of S6 and S7 results with and without CCUS? Where do these findings come from without CCUS?

Commented [IGC172R171]: As noted previously, all of our scenarios include both fossil fuel technologies w/ and w/o CCUS. The point of this statement is to compare S6 and S7 that have climate policy with other scenarios S1-S5 without climate policy. Compared to the scenarios ***without*** climate policy (S1-S5), the scenarios ***with*** climate policy (S6-S7) have lower fossil w/o CCUS.

Commented [JG173]: This read like it was going to make a comparison but didn't quite do it. I tweaked it - please make sure the intended meaning is still conveyed

Commented [ST174]: Equivalent level of results are missing for S6/S7 as reported in Items #1 thru #7. MAF for S6/S7 is not discussed in the conclusion section, for example.

APPENDIX A: GLOBAL ANALYSIS AND DESCRIPTION OF GCAM

A. Additional Detail on GCAM's Energy System

GCAM's energy system contains representations of fossil resources (coal, oil, gas), uranium, and renewable sources (wind, solar, geothermal, hydro, biomass, and traditional biomass) along with processes that transform these resources to final energy carriers (electricity generation, refining, H_2 production, natural gas processing, and district heat), which are ultimately used to deliver goods and services demanded by end use sectors (residential buildings, commercial buildings, transportation, and industry). Each of the sectors in GCAM includes technological detail. For example, the electricity generation sector includes several different technology options to convert coal to electricity such as pulverized coal with and without CCUS; and coal integrated gasification combined cycle with and without CCUS. The full list of technologies in various sectors in GCAM can be found on the GCAM documentation page (http://jgcri.github.io/gcam-doc/).

In every sector within GCAM, individual technologies compete for market share based on the levelized cost of a technology. The cost of a technology in any period depends on (1) its exogenously specified non-energy cost, (2) its endogenously calculated fuel cost, and (3) any cost of emissions as determined by the climate policy. The first term, non-energy cost, represents capital, fixed, and variable O&M costs incurred over the lifetime of the equipment (except for fuel or electricity costs), expressed per unit of output. For example, the non-energy cost of coal-fired power plant is calculated as the sum of overnight capital cost (amortized using a capital recovery factor and converted to dollars per unit of energy output by applying a capacity factor), fixed and variable O&M costs. The second term, fuel or electricity cost, depends on the specified efficiency of the technology, which determines the amount of fuel or electricity required to produce each unit of output, as well as the cost of the fuel or electricity. The various data sources and assumptions can be found on the GCAM documentation page (http://jgcri.github.io/gcam-doc/). The prices of fossil fuels and uranium are calculated endogenously. Fossil fuel resource supply in GCAM is modeled using graded resource supply curves that represent increasing cost of extraction as cumulative extraction increases. Wind and rooftop photovoltaic technologies include resource costs that are also calculated from exogenous supply curves that represent marginal costs that increase with deployment, such as long-distance transmission line costs that would be required to produce power from remote wind resources. Utility-scale solar photovoltaic and concentrated solar power technologies are assumed to have constant marginal resource costs regardless of deployment levels.

In GCAM, technology choice is determined by market competition. The market share captured by a technology increases as its costs decline, but GCAM uses a logit model of market competition. This approach is designed to represent decision making among competing options when only some characteristics of the options can be observed and avoids a "winner take all" response.

For the purposes of this project, historical natural gas producer prices in the United States are calibrated to the Henry Hub prices from EIA[28]; in Canada, they are calibrated to Alberta marker prices from BP's *bp*

[28] U.S. EIA (2023). Henry Hub Natural Gas Spot Price. Available at: https://www.eia.gov/dnav/ng/hist/rngwhhda.htm

Statistical Review.[29] For the rest of the world, natural gas producer prices in each GCAM region are based on the cost, insurance, and freight prices from S&P Global (see Table A-1).[30] In a future model period, as demand changes, the change in regional producer prices from the historical calibrated values are calculated endogenously using regional supply curves that represent increasing cost of extraction as cumulative extraction increases.

Table A-1. Historical natural gas producer prices used for calibration in GCAM

GCAM Region	Natural Gas Producer Prices (2022 $/MMBtu)
European Free Trade Association	1.61
Australia_NZ	1.89
Canada	2.45
Middle East	2.66
Africa_Northern	3.13
USA	3.17
Indonesia	3.61
South Asia	4.48
Southeast Asia	4.48
Central America and Caribbean	4.56
South America_Southern	4.56
Russia	5.76
Africa_Western	6.11
EU-12	8.61
EU-15	8.61
Europe_Non_EU	8.61
Africa_Eastern	9.48
Africa_Southern	9.48
China	11.08
India	11.08
Pakistan	11.08
Taiwan	11.97
Argentina	13.19
Brazil	13.19
Colombia	13.19
South America_Northern	13.19
Mexico	13.19
South Korea	13.37
Japan	13.43

[29] BP (2022). bp Statistical Review of World Energy. 71st edition. Available at: https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/statistical-review/bp-stats-review-2022-full-report.pdf

[30] S&P Global (2023). S&P Global Commodity Insights. Historical and forecasted LNG prices data sheet.

B. Additional Detail on Scenario Design

Table A-2. Detailed assumptions in S4

Region Type	GCAM Regions	High-Level Target/Sanction
Developed countries, natural gas importers with sufficient domestic resources	EU-12, EU-15, Europe_Eastern, Europe_Non_EU	Reduce gross imports to 90% by 2035 and zero by 2040
Developed countries, natural gas importers with low domestic natural gas resources	Japan, South Korea, Taiwan	Maintain current import dependence through 2050
Developing countries, natural gas importers	Brazil, China, India, Pakistan, Southeast Asia, Mexico, South Africa	Maintain current import dependence through 2050
Natural gas exporters	USA, Africa_Eastern, Africa_Northern, Africa_Southern, Africa_Western, Australia_NZ, Canada, Central America and Caribbean, Central Asia, European Free Trade Association, Indonesia, Middle East, South America_Southern, South America_Northern, South Asia, Colombia, Argentina	Reduce gross imports to 90% by 2035 and zero by 2040
Russia	Russia	Same as *S2*

C. Additional GCAM Results

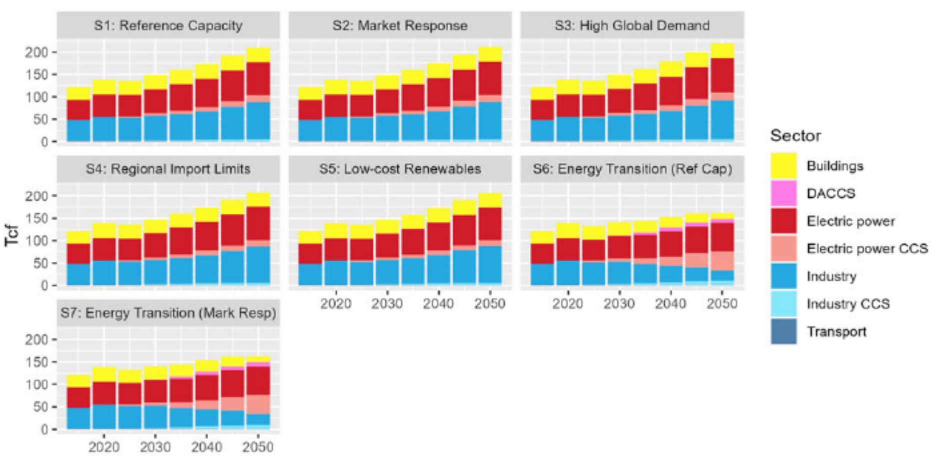

Figure A-1. Global natural gas consumption by sector across all scenarios. Conversion factors are as follows: 1 Tcf/yr = 2.74 Bcf/d and 1 Bcf/d = 0.36 Tcf/yr

Commented [UP175]: In the body of the report, we showed results in Bcf/d but in Appendix reverted back to Tcf making the comparisons of consumption and production not matching to the body of the report. LNG exports here are still shown as Bcf/d though so not consistent.

Commented [IGC176R175]: For the figures in main report, we decided to stick with the same units for all panels that show consumption, production, exports, and imports (e.g. Figure 4) to enhance readability. Since the focus of this study is on LNG exports, we decided to stick to BCF/day for those figures. Bcf/day is the unit commonly used to measure exports.

However, figures in the appendix follow more conventional untis (Tcf/yr for consumption and production; and Bcf/day for imports and exports). We have included data corresponding to all figures in the main section of the report in the corresponding units in Appendix D. To facilitate comparison between figures in the main report and this appendix, we have included conversion factors in the legends.

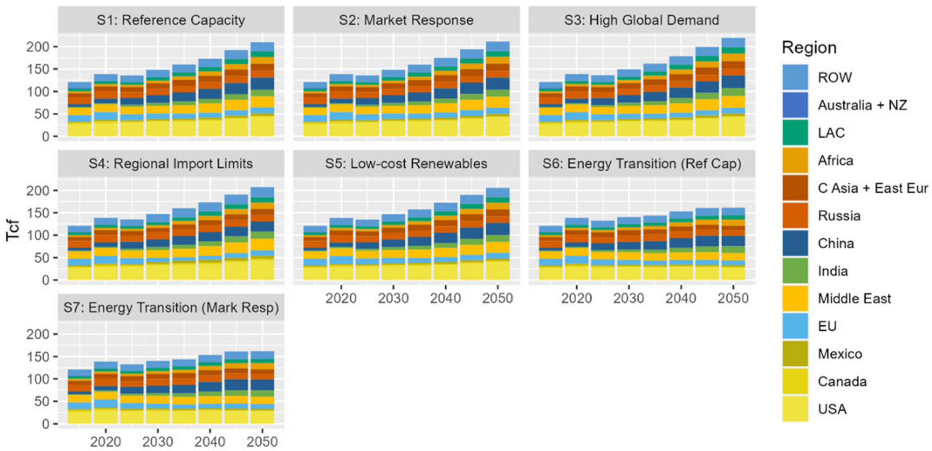

Figure A-2. Global natural gas consumption by region across all scenarios. Conversion factors are as follows: 1 Tcf/yr = 2.74 Bcf/d and 1 Bcf/d = 0.36 Tcf/yr

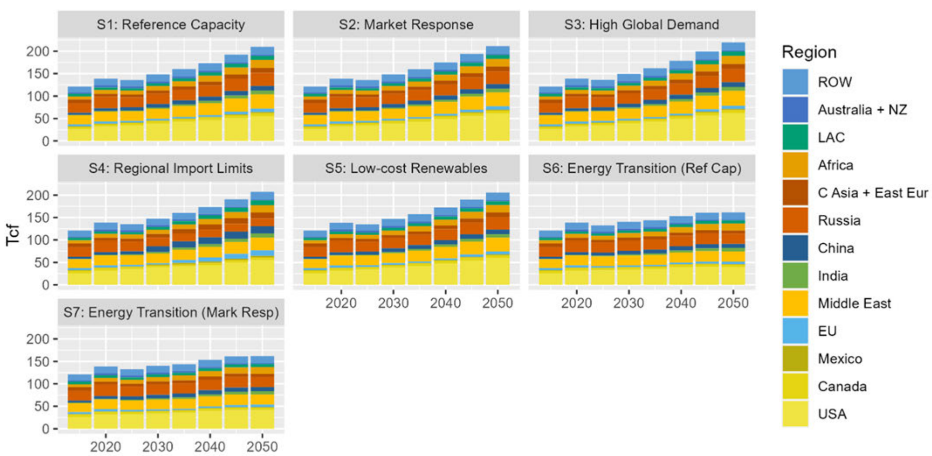

Figure A-3. Global natural gas production by region across all scenarios. Conversion factors are as follows: 1 Tcf/yr = 2.74 Bcf/d and 1 Bcf/d = 0.36 Tcf/yr

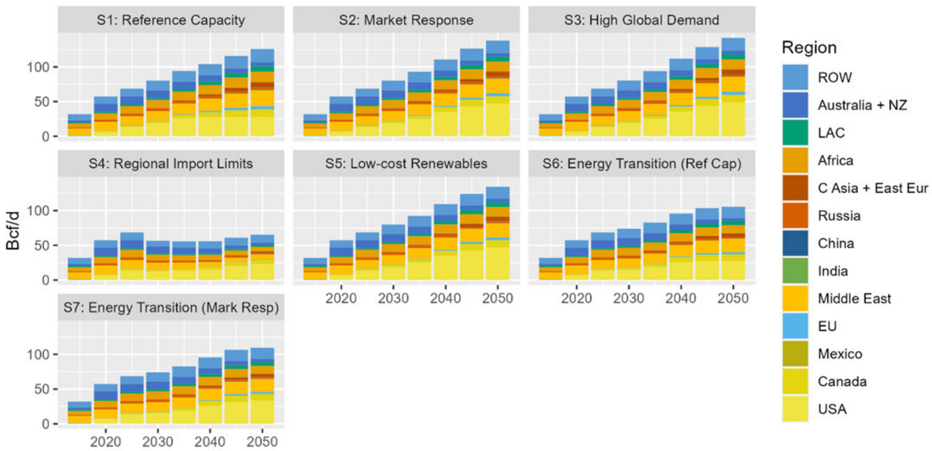

Figure A-4. Global LNG exports by region across all scenarios. Conversion factors are as follows: 1 Tcf/yr = 2.74 Bcf/d and 1 Bcf/d = 0.36 Tcf/yr

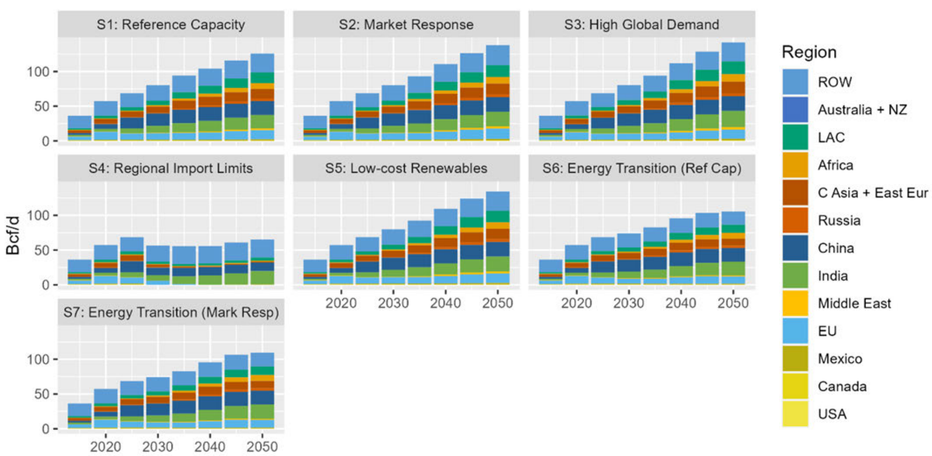

Figure A-5. Global LNG imports by region across all scenarios. Conversion factors are as follows: 1 Tcf/yr = 2.74 Bcf/d and 1 Bcf/d = 0.36 Tcf/yr

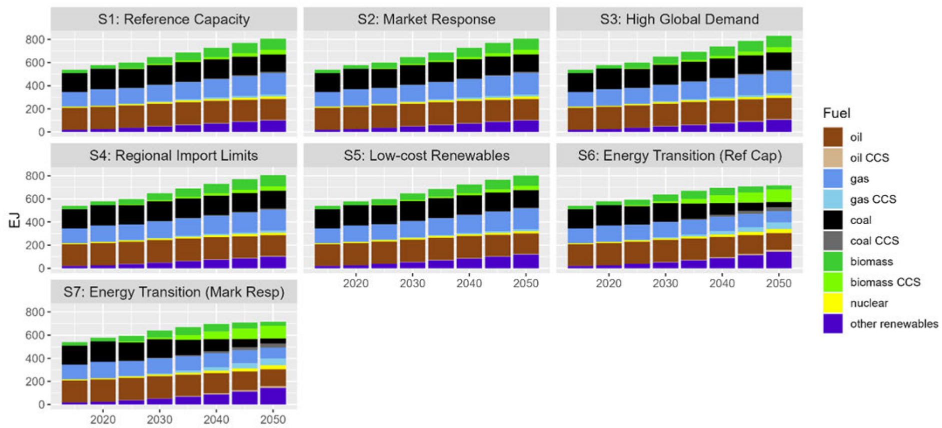

Figure A-6. Global primary energy consumption by fuel across all scenarios

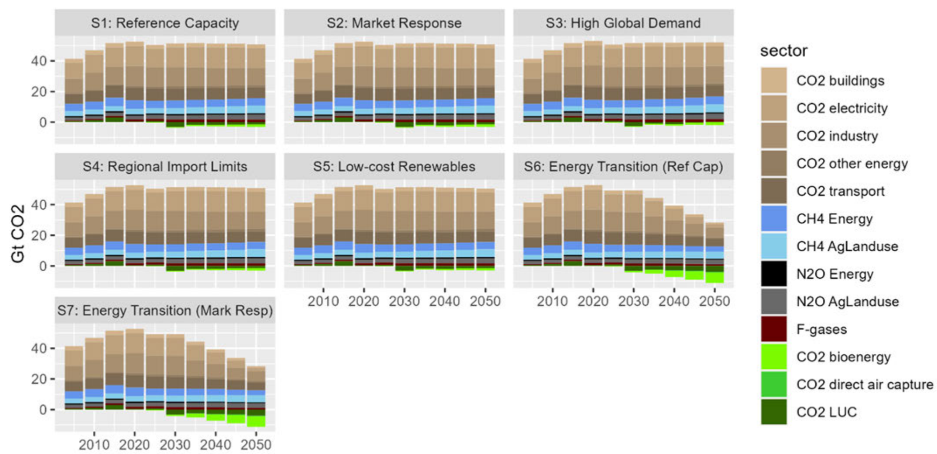

Figure A-7. Global GHG emissions by sector across all scenarios

APPENDIX B: U.S. ANALYSIS AND DESCRIPTION OF AEO2023-NEMS AND FECM-NEMS

A. Modeling U.S. LNG Exports

AEO2023-NEMS and FECM-NEMS have two methods available to calculate LNG export capacity: endogenous and exogenous. There is a switch in the input files that can be toggled between the two methods before executing a run. *S1* is the AEO2023 Reference Scenario, which calculates LNG export capacity endogenously; *S2–S7* are initialized with exogenous LNG export capacity, which use LNG export values from GCAM for each scenario. The LNG export capacity in *S6* is exogenously set to equal the capacity in *S1*. Both AEO2023-NEMS and FECM-NEMS follow a similar process with only minor differences in a small number of input values. In most scenarios (including all scenarios discussed in this report) LNG exports will equal LNG export capacity because the cost to construct capacity is so high that capacity will rarely be left unused once built. Therefore, the following description can be treated as an explanation for how AEO2023-NEMS and FECM-NEMS calculate LNG export volumes.

Commented [UP177]: Is this sentence correct? Maybe was written pre-S7? I edited it but needs a check.

Commented [DH178R177]: The sentence was inaccurate - we've reworded it to clarify that S1 is endogenous and S2 through S7 are exogenous, even though the values from S6 equal S1.

Commented [HH179]: Unneeded, as S1 has been identified as the AEO ref scenario in the previous sentence.

The algorithm for calculating LNG export capacity endogenously has two steps. First, AEO2023-NEMS considers LNG exports from existing or planned LNG export facilities. Beginning with Cheniere's Sabine Pass facility, which started exporting LNG in 2016, AEO2023-NEMS runs through a list of export facilities specified in an input file. This list is updated with each version of the AEO; AEO2023-NEMS includes existing and planned facilities expected to start or expand production by the end of 2025. For each facility, AEO2023-NEMS slowly increases production over the first few months to represent an export facility ramping up to full capacity.

The second step in the endogenous algorithm involves a prediction of future LNG exports. AEO2023-NEMS uses a set of exogenous values in an input file to specify how much demand Europe and Asia will have for LNG imports, as well as how much supply of non-U.S. LNG will exist on the market. Then, considering the volume of U.S. LNG exports at a given model year, AEO2023-NEMS calculates how the ratio of supply and demand changes over time. This ratio, together with the world oil price, is used to calculate the price at which international customers will purchase U.S. LNG. The purchase price algorithm is constructed in such a way that rises in the oil price, decreases or slowdowns in future LNG supply, or increases in future LNG demand will all increase the purchase price of LNG, and vice-versa. The influence that each factor has on LNG purchase price is controlled by several input parameters.

In addition to a purchase price, AEO2023-NEMS calculates the price at which U.S. LNG could be sold. This "sale price" combines the natural gas Henry Hub price with various costs that represent the stages of preparing pipeline gas for LNG transport (including liquefaction, fuel consumption, shipping, and regasification). AEO2023-NEMS then compares the sale price to purchase prices at different destinations and determines a discounted net present value of new LNG construction over the subsequent 20 years. Depending on the net present value, AEO2023-NEMS will decide to increase LNG export capacity by 0–600 Bcf/d. The increase in capacity takes effect after a four year "construction" period and brief "phase-in" period.

An input file is read by AEO2023-NEMS to define LNG export capacity exogenously. A table in an input file lists LNG export capacity by year; these values are used by AEO2023-NEMS to set LNG exports for that year. In *S2–S7*, various parameters, including LNG export volumes, are calculated by GCAM. The LNG export volumes are converted to the correct input format and adopted by AEO2023-NEMS as the exogenous LNG export capacity.

Commented [UP180]: S7?

Commented [DH181R180]: Apologies, S7 is correct

B. Additional Detail on U.S. Natural Gas Markets

1. Regional Natural Gas Production

Figure B-1 and Figure B-2 plot onshore natural gas production by region for the first five scenarios and the net-zero scenarios, respectively, in 2025 and 2050. Offshore natural gas production comprises a small portion of the total (<4% in all scenarios and years) and is omitted from these figures.

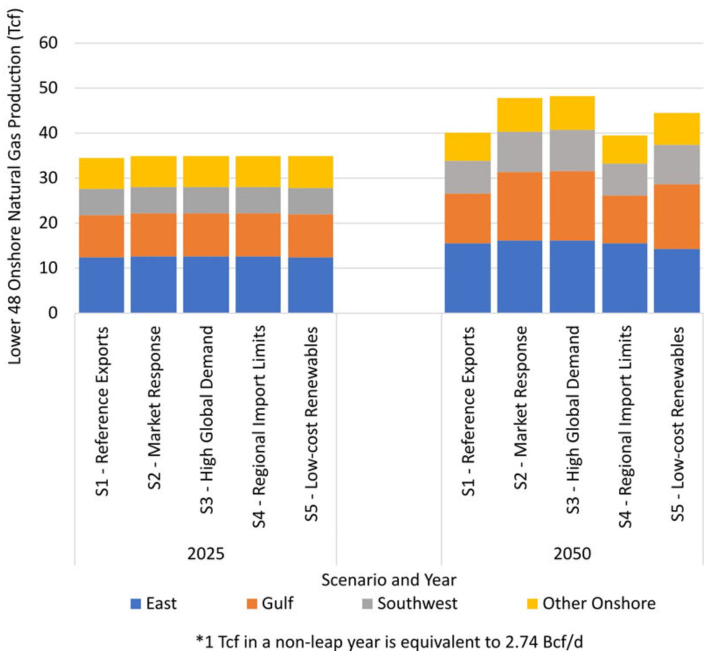

Figure B-1. U.S. regional natural gas production, S1–S5

Onshore natural gas production experienced an upward trend across all scenarios by 2050, equaling or exceeding 39 Tcf. *S3* exhibited the highest production level at 48.3 Tcf, influenced by the global demand for natural gas. Expansion is primarily characterized by a significant increase in production in the Gulf region, subsequently followed by the Southwest and the East. Conversely, *S4* sees the lowest natural gas production with least production growth in the Gulf region (1.4 Tcf from 2025 to 2050).

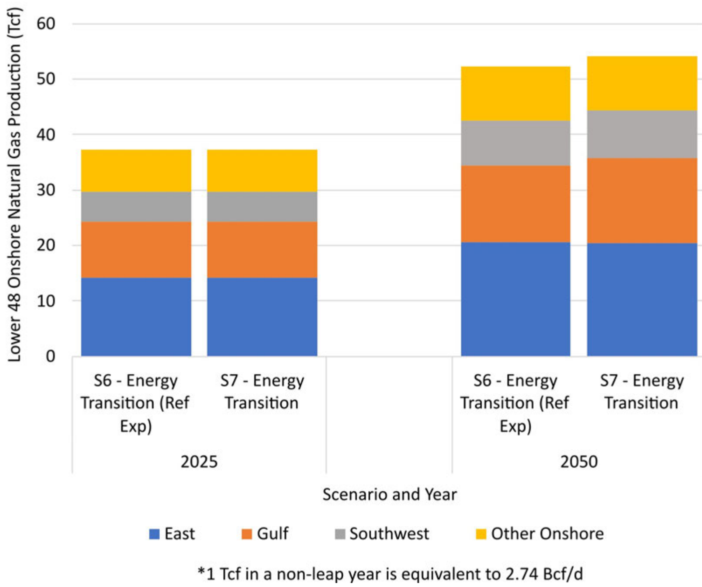

Figure B-2. U.S. regional natural gas production in S6 and S7

Similarly, onshore natural gas production grows significantly from 2025 to 2050 for both net-zero scenarios, rising from 37.3 Tcf in 2025 to 52.3 Tcf in *S6* and 54.1 Tcf in *S7*, respectively, by 2050. The large growth in natural gas production is primarily due to demand from DAC facilities, with only a small increase associated with elevated LNG exports in the *S7* scenario. Natural gas production rises in all regions, with the largest absolute increases coming from the East (6.4 Tcf in *S6* and 6.2 Tcf in *S7*) and Gulf (3.8 Tcf in *S6* and 5.2 Tcf in *S7*) regions and the largest increase by percentage coming from the Southwest (47% in *S6* and 58% in *S7*).

2. Natural Gas Consumption by Economic Sector

Figure B-3 plots natural gas consumption for electric power, industry, residential use, commercial use, and transportation over time for *S1–S5*. These sector-by-sector plots sum to equal the "Natural Gas Consumption" subplot displayed in Figure 16.

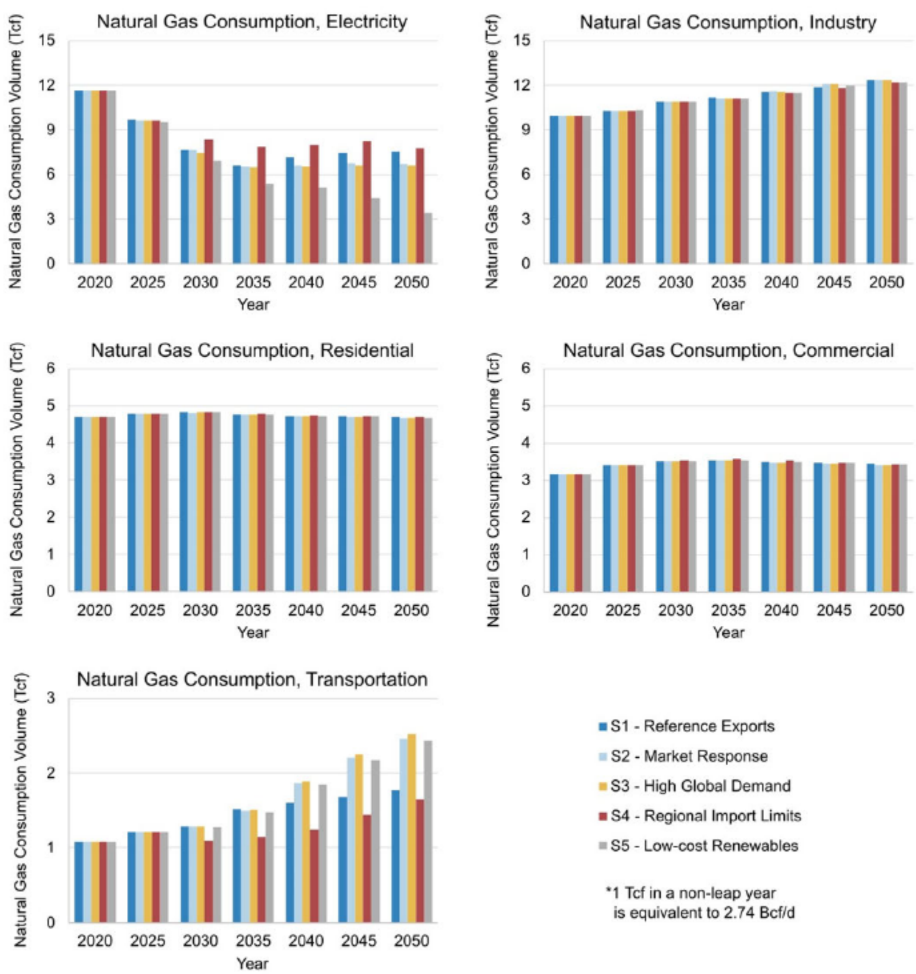

Figure B-3. U.S. natural gas consumption by sector, S1–S5

Natural gas consumed for electricity was inversely correlated with LNG exports and natural gas prices for *S1–S4*. From a starting point of 11.6 Tcf in 2020, the first three scenarios drop to similar consumption volumes of 6.6, 6.5, and 6.6 Tcf in 2035 before slightly increasing to 7.6 Tcf (*S1*) or plateauing at 6.7 and 6.6 Tcf (*S2* and *S3*, respectively) in 2050. The increased consumption of natural gas for electricity in *S1* can be explained as a response to price reductions caused by plateauing LNG exports, whereas high prices and exports in *S2* and *S3* lead to a flat consumption trend. *S4*—the scenario with the fewest exports and lowest prices through the first half of the model—exhibited the highest consumption for electricity in 2035 of 7.9 Tcf, which rises and falls slightly to a similar level to *S1* in 2050 (7.8 Tcf). *S5* is again an outlier here, reporting consistently lower natural gas consumption that hit a minimum of 3.4

Commented [UP182]: Hard to compare by sector data to the totals in the report as the report had the data in Bcf/d and in the Appendix we are now showing results in Tcf.

Commented [DH183R182]: Added a sentence to emphasize that this figure should be compared against Figure 16, and included a note about conversions from Tcf to Bcf/d. We will go through the report to improve unit consistency.

Tcf in 2050. This trend is a consequence of its low renewable costs reducing the demand for natural gas in the electric sector.

Unlike electricity, there was no significant difference between scenarios in the rate of natural gas consumption in the industrial, residential, or commercial sectors. Industrial natural gas consumption rises from 9.9 Tcf in 2020 to 12.2–12.4 Tcf in 2050 across the five scenarios; residential consumption remains relatively unchanged at 4.7 Tcf from 2020 to 2050 with some small variations; and commercial consumption rises and falls slightly from 3.2 Tcf in 2020 to 3.4 Tcf in 2050.

Natural gas consumed for transportation has a different response to changes in LNG exports, compared with the other consumptions sectors. The transportation category is dominated by pipeline fuel: natural gas consumed to power infrastructure underlying the natural gas supply chain, which includes LNG exports. Increases in natural gas consumption for transportation, therefore, correlate strongly with the quantity of LNG exports; *S3* exhibits the highest consumption in the transportation sector by 2050 (2.5 Tcf), followed by *S2* and *S5* (2.5 and 2.4 Tcf), *S1*, and finally *S4* (1.6 Tcf).

The sector-by-sector changes across the five scenarios end up cancelling each other out for *S1–S4*, leading to nearly identical total natural gas consumption values, as seen in Figure 16. Only *S5*, thanks to its low renewable costs, exhibits a lower overall U.S. natural gas consumption trend.

Significant changes to the energy economy (going from AEO2023-NEMS to FECM-NEMS) that occur to satisfy the net-zero criteria make comparisons of *S1–S5* with *S6* and *S7* imprecise. Relative to *S1*, natural gas consumption values decline across most sectors in *S6* and *S7* but are substantially higher in the industry sector (where DAC consumption is categorized). Figure B-4 plots natural gas consumption for the net-zero scenarios on a sector-by-sector basis. The individual subplots are subsets of the "Natural Gas Consumption" subplot displayed in Figure 17.

Commented [HH184]: This is the only time in the text FECM-NEMS is given as FECM22-NEMS. If this is a slight variation, it needs to be introduced.

Commented [UP185]: Do we want to say this like this-that it's complicated to go from AEO2023-NEMS to FECM22-NEMS? Again sounds too informal for a description of a model. All forecasting is complicated😉

Commented [DH186R185]: Reworded to make the statement more formal

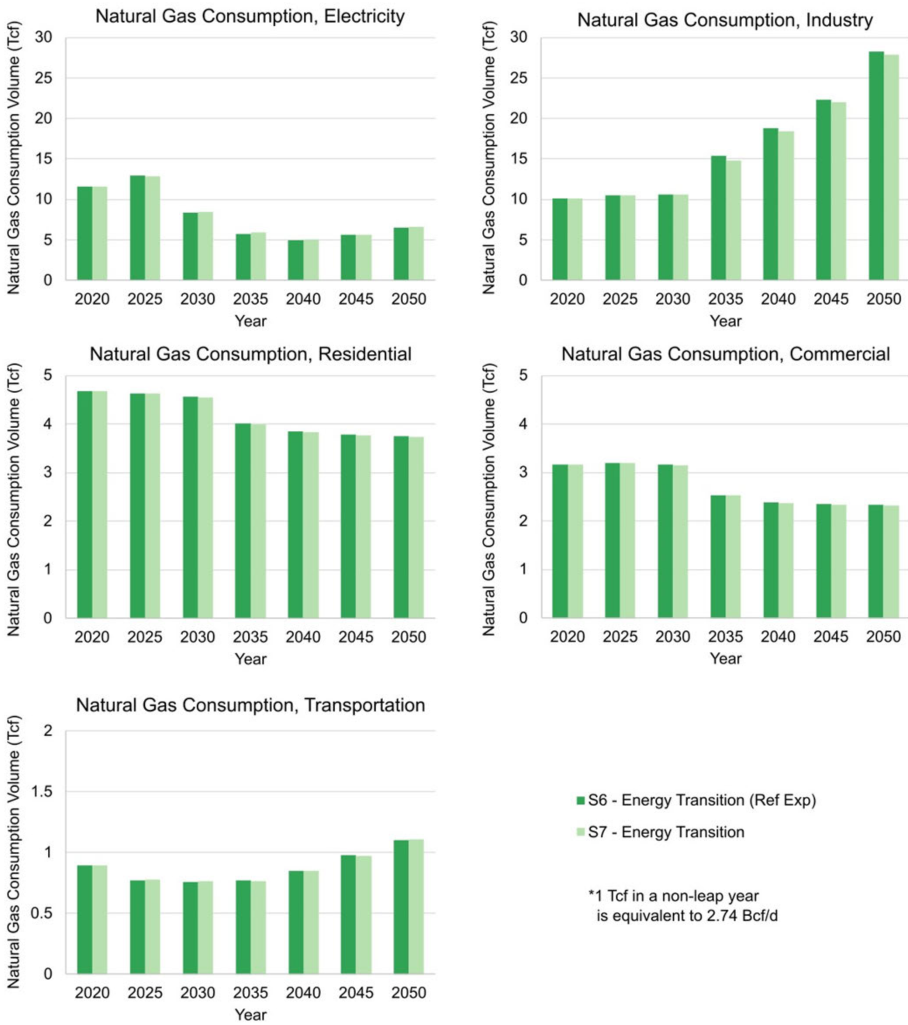

Figure B-4. U.S. natural gas consumption by sector, net-zero scenarios

Differences in historical natural gas consumption and subsequent short-term effects cause a difference in natural gas consumption for electricity in 2020 and 2025 between *S6* and *S7* (from FECM-NEMS) and *S1–S5* (from AEO2023-NEMS). Similar differences in the historical data exist for all sector-specific consumption values. Volumes of natural gas consumed for electricity track closely between the two net-zero scenarios across most of the modeling years, ranging 5.7–5.9 Tcf in 2035 for *S6* and *S7*, respectively, and rising in later years to 6.5 Tcf and 6.6 Tcf. *S6* reports a lower natural gas consumption value in 2050 than *S1* (7.6 Tcf), but the corresponding result for *S7* is fairly close to *S2* (6.7 Tcf).

Industry-sector natural gas consumption exhibits the largest change between *S6* and *S7* relative to *S1–S5*, thanks to the strong influence of DAC. Whereas industry consumption of natural gas in *S1* and *S2* both increase from 9.9 Tcf to 12.3 Tcf from 2020 to 2050, the net-zero scenarios diverge after 2030 and grow rapidly to 28.2 and 27.8 Tcf for *S6* and *S7*, respectively, by 2050. The difference in consumption values is consistent with the natural gas consumption for DAC, which is plotted in Figure B-5.

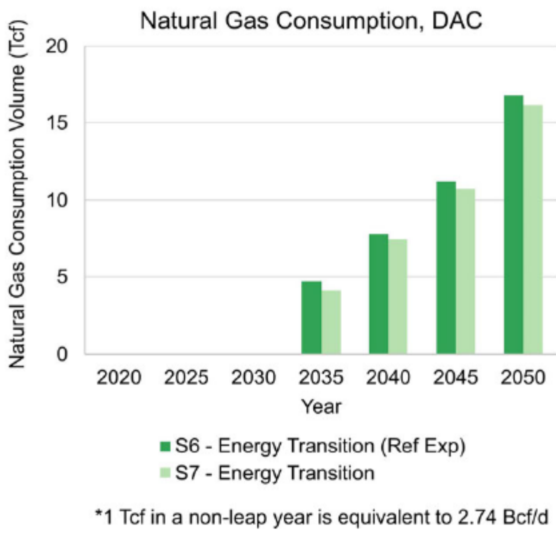

Figure B-5. Natural gas consumed for DAC, net-zero scenarios

Residential- and commercial-sector natural gas consumption follow similar behavior. These values decrease in both net-zero scenarios across the model years 2020–2030 from 4.7 to 3.7 Tcf (residential) and from 3.2 to 2.3 Tcf (commercial). By comparison, both *S1* and *S2* have static or slightly increasing trends, with both reporting 4.7 Tcf in 2020 and 2050 for residential consumption and 3.2 to 3.4 Tcf from 2020 to 2050 for commercial consumption.

Transportation is the smallest of the five sectors in terms of natural gas consumption volumes, and calculation differences between AEO2023-NEMS and FECM-NEMS lead to large impacts on the consumption values. As a result, these values are not directly comparable between the three scenarios. *S6* and *S7* have nearly identical volumes of natural gas consumed for the transportation sector, varying from 0.9 Tcf in 2020 to 0.8 Tcf in 2035 and 1.1 Tcf in 2050. By comparison, *S1* and *S2* report consistently higher natural gas consumption for transportation across the model years, ranging from 1.1 Tcf in 2020 to 1.8 and 2.3 Tcf, respectively, in 2050.

DAC is the main technology used by FECM-NEMS to meet the CO_2 cap and by 2050 is responsible for removing 1.93 Gt CO_2 per year in *S6* and 1.85 Gt CO_2 per year in *S7*. A considerable amount of natural gas is consumed to support these levels of DAC: 16.8 Tcf and 16.2 Tcf in 2050 for *S6* and *S7*, respectively. More detail on cost assumptions for DAC in FECM-NEMS is given in the section below.

Commented [WS187]: Would be very helpful to state our assumptions regarding the cost of DAC over the 2035 to 2050 period.

In conclusion, even though four out of the five sectors exhibit decreases when comparing natural gas consumption in *S6* and *S7* to *S1* and *S2*, the strong increases in the industrial sector (mainly from increases in DAC) cause overall U.S. natural gas consumption to be significantly higher by 2050 in *S6* and *S7*. There is minimal difference between the *S6* and *S7* results, suggesting that the differences in LNG exports between the net-zero scenarios play a limited role in altering natural gas consumptions trends.

C. CO_2 Removal Technologies and Carbon Prices in FECM-NEMS

CO_2 removals in FECM-NEMS are driven by three technologies: production of H_2 with sequestered biomass, BECCS, and DAC. Figure B-6 plots CO_2 removals for each technology and scenario by year.

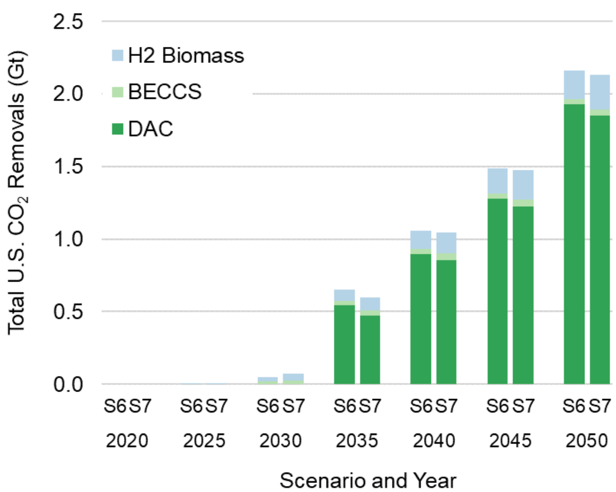

Figure B-6. U.S. CO_2 emissions and removals, S6 and S7

DAC is most widely used in both net-zero scenarios and scales up rapidly after 2030 to account for 1.93 Gt CO_2 removed in *S6* and 1.85 Gt CO_2 removed in *S7* (89% and 87% of total removals, respectively) by 2050. H_2 production with biomass and BECCS see significantly less adoption by 2050 in both scenarios; the former reaches 0.20 (9% of total) and 0.24 (11% of total) Gt CO_2 removed in *S6* and *S7*, respectively, whereas the later reaches approximately 0.04 Gt CO_2 removed in both scenarios (2% of total removals).

Table B-1 lists specific cost and technical assumptions underlying DAC in FECM-NEMS.

Table B-1. DAC technology assumptions in FECM-NEMS

	Capital Expenses, $2022/ton	Capital Recovery Factor	Capital Expenses, $2022/ton-year	Operating Expenses, $2022/ton-year	Electricity demand, kilowatt-hour/ton	Natural Gas Demand, MMBtu/ton
Grid	$1,451	7.1%	$125	$79.2	450	8.75
NG Only	$1,674	7.1%	$144	$93.3	0	9.27

Commented [DH188]: @Peter Whitman Hi Pete, I updated the $ year for the prices here and reworded some things. Is there anything else we can add to the description here?

FECM-NEMS relies on two sets of DAC technology assumptions: "grid," and "NG only," derived from the literature using updated cost and performance data from FECM.[31] Both use natural gas to power the capture process; DAC-grid offsets some of the natural gas demand by using electricity. Both technologies follow a learning curve that reduces the capital cost of deployment over time, and both use a capital recovery factor of 7.1%.

The effect of DAC on natural gas markets in *S6* and *S7* can be seen in the rapid growth of total natural gas consumption and subsequent rise in natural gas prices (Figure 18) in the main text. By 2050, natural gas consumption equals 16.8 Tcf and 16.2 Tcf for *S6*, and *S7*, respectively, reaching natural gas prices of $6.34/Mcf and $6.20/Mcf ($2022).

FECM-NEMS models the deployment of carbon removal technologies by determining a CO_2 price that represents the market equilibrium cost to capture and abate CO_2 emissions. FECM-NEMS adjusts the CO_2 price in accordance with the imposed carbon cap to ensure that the correct number of CO_2 emissions are abated each year. End-use prices are then adjusted by the product of the unsequestered carbon content of the fuel and the implied carbon price to reflect the carbon penalty of combustion. Residential natural gas prices, reflecting the implied carbon penalty, are $34.97/Mcf and $35.24/Mcf in *S6* and *S7*, respectively, by 2050.

[31] National Academies of Sciences, Engineering, and Medicine. (2019). Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. Washington, DC: The National Academies Press. https://doi.org/10.17226/25259.

Appendix C: Supporting LCA

A. NEMS and NETL LCA Model Comparison

The NEMS modeling done in this project focused on domestic changes that would be expected to occur in the seven scenarios modeled. NETL reviewed the NEMS data to evaluate if the regional production mix of natural gas would be expected to change over time. 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 adjustments would be recommended to the assumed GHG intensity for U.S. natural gas in the results.

For *S1–S7*, NEMS-modeled data of dry natural gas production of "Production by OGSM District" were mapped to a state and then to an NETL natural gas model region as shown in Table C-1. Note that several "states" are offshore regions.

Commented [UP189]: What's OGSM? Needs to also be included under Acronyms/Abbreviations Table.

Commented [PW190R189]: Added to table

Table C-1. Matching NEMS (Oil and Gas Methane Partnership states) to NETL states and subsequently regions

Production by OGSM District	State	Region
Alabama, North	Alabama	Southeast
Alabama, South	Alabama	Southeast
Arizona	Arizona	Southwest
Arkansas	Arkansas	Southeast
California	California	Pacific
Colorado	Colorado	Rocky Mountain
Connecticut	Connecticut	Northeast
Delaware	Delaware	Northeast
Florida	Florida	Southeast
Georgia	Georgia	Southeast
Idaho	Idaho	Rocky Mountain
Illinois	Illinois	Midwest
Indiana	Indiana	Midwest
Iowa	Iowa	Midwest
Kansas	Kansas	Midwest
Kentucky	Kentucky	Southeast
Louisiana, North	Louisiana	Southeast
Louisiana, South	Louisiana	Southeast
Maryland	Maryland	Northeast
Massachusetts	Massachusetts	Northeast
Michigan	Michigan	Midwest
Minnesota	Minnesota	Midwest
Mississippi, North	Mississippi	Southeast
Mississippi, South	Mississippi	Southeast
Missouri	Missouri	Midwest

Production by OGSM District	State	Region
Montana	Montana	Rocky Mountain
Nebraska	Nebraska	Midwest
Nevada	Nevada	Rocky Mountain
New Hampshire	New Hampshire	Northeast
New Jersey	New Jersey	Northeast
New Mexico, East	New Mexico	Southwest
New Mexico, West	New Mexico	Southwest
New York	New York	Northeast
North Carolina	North Carolina	Southeast
North Dakota	North Dakota	Midwest
Ohio	Ohio	Midwest
Oklahoma	Oklahoma	Southwest
Oregon	Oregon	Pacific
Pennsylvania	Pennsylvania	Northeast
Rhode Island	Rhode Island	Northeast
South Carolina	South Carolina	Southeast
South Dakota	South Dakota	Midwest
Tennessee	Tennessee	Southeast
Texas RRC 1	Texas	Southwest
Texas RRC 2	Texas	Southwest
Texas RRC 3	Texas	Southwest
Texas RRC 4	Texas	Southwest
Texas RRC 5	Texas	Southwest
Texas RRC 6	Texas	Southwest
Texas RRC 7B	Texas	Southwest
Texas RRC 7C	Texas	Southwest
Texas RRC 8	Texas	Southwest
Texas RRC 8A	Texas	Southwest
Texas RRC 9	Texas	Southwest
Texas RRC 10	Texas	Southwest
Utah	Utah	Rocky Mountain
Virginia	Virginia	Northeast
Washington	Washington	Pacific
West Virginia	West Virginia	Northeast
Wisconsin	Wisconsin	Midwest
Wyoming	Wyoming	Rocky Mountain
Alabama State Offshore	Alabama	Southeast
Louisiana State Offshore	Louisiana	Southeast
Texas State Offshore	Texas	Southwest
California State Offshore	California	Pacific

Production by OGSM District	State	Region
North Atlantic Federal Offshore	North Carolina	Southeast
Mid Atlantic Federal Offshore	Federal Offshore - GoM	Southeast
South Atlantic Federal Offshore	South Carolina	Southeast
Eastern GOM Federal Offshore	Federal Offshore - GoM	Southeast
Central GOM Federal Offshore	Federal Offshore - GoM	Southeast
Western GOM Federal Offshore	Federal Offshore - GoM	Southeast
California Federal Offshore	California	Pacific
Northern Pacific Federal Offshore	Federal Offshore - GoM	Southeast
Alaska Federal Offshore	Federal Offshore - GoM	Southeast

This classification enables the aggregation of dry production data (excluding extraction losses) by region for each respective year, as summarized with every 10 years of data in Table C-2.

Table C-2. Regional dry production (Tcf) between 2020 and 2050, S1

Region	2020	2030	2040	2050
Midwest	3.27	2.82	2.41	2.09
Northeast	9.54	11.14	13.03	14.08
Pacific	0.16	0.29	0.30	0.28
Rocky Mountain	3.33	2.90	2.80	2.69
Southeast	4.59	6.08	6.65	5.72
Southwest	12.28	13.37	15.28	16.65

From this aggregated data, the production share is calculated by dividing the region-specific production by the total U.S. production for each year and is summarized in Table C-3.

Table C-3. Regional NG dry production shares, S1

Region	2020	2030	2040	2050
Midwest	0.099	0.077	0.060	0.050
Northeast	0.288	0.304	0.322	0.339
Pacific	0.005	0.008	0.007	0.007
Rocky Mountain	0.100	0.079	0.069	0.065
Southeast	0.138	0.166	0.164	0.138
Southwest	0.370	0.365	0.378	0.401

Figure C-1 shows the percent of natural gas dry production for each region of *S1* as compared to total production in each year between 2020 and 2050. The same process was done for the other scenarios.

Commented [ST191]: Why every 10 years of data when the raw data is provided on an annual basis from NEMS?

Commented [SM192R191]: The model uses annual data this is just to avoid cluttering the document, is why as an example every 10 years of data is included.

Commented [ST193]: How much variability in dry production volume is considered significant? Northeast is a 55% increase.
60% decrease in Midwest.

Commented [ST194]: No discussion of Table C-3.

Ratio compared to what?

I think these are annual percentages. Column sums to 100%.

Caption needs better clarity.

Commented [SM195R194]: As a proportion of total US production. Additional text provided above Table C-3 for clarity.

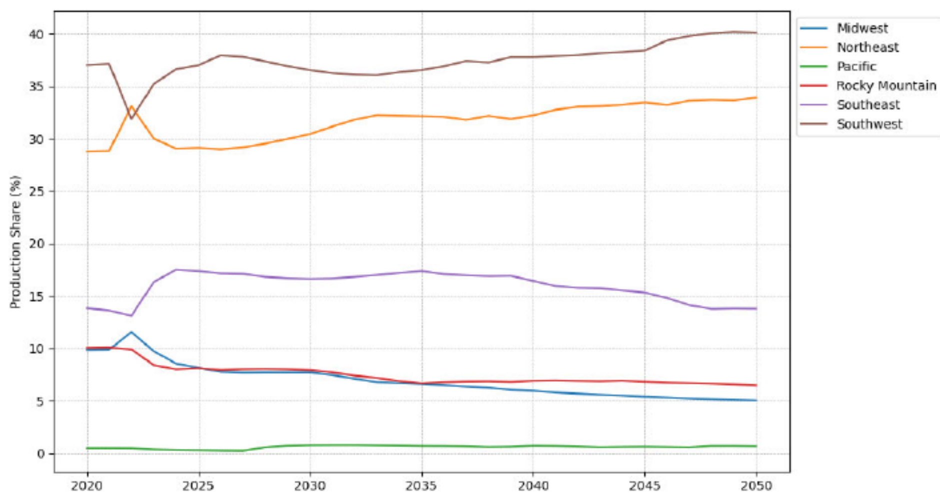

Figure C-1. Dry NG production percentage time-series for each region

The regional production shares estimated based on NEMS data are disaggregated to a techno-basin level based on the proportion of regional natural gas production shares in the 2020 NETL Natural Gas model.[19] Based on the 2020 NETL Natural Gas model, Table C-4 provides the techno-basin to region mapping details and Table C-5 reports the GHG emissions intensity results for natural gas production from all techno-basins, for the production through transmission network life cycle boundary, using U.S. average transmission network data.

Table C-4. Techno-basin to region mapping

Techno-basin	Region
Alaska Offshore	Pacific
Anadarko Conventional	Southwest
Anadarko Shale	Southwest
Anadarko Tight	Southwest
Appalachian Shale	Northeast
Arkla Conventional	Southeast
Arkla Shale	Southeast
Arkla Tight	Southeast
Arkoma Conventional	Southwest
Arkoma Shale	Southwest
East Texas Conventional	Southwest
East Texas Shale	Southwest
East Texas Tight	Southwest
Fort Worth Shale	Southwest
GoM Offshore	Southeast
Green River Conventional	Rocky Mountain

Commented [ST196]: GHG Emissions Intensity

Commented [ST197]: There should be a space between the measurement unit and the descriptor of what was measured/reported.

E.g., g CO2e (with the 2 subscripted)

Commented [ST198]: How were the regional profiles converted to a single Weighted Average GHG Emissions Intensity value?

Techno-basin	Region
Green River Tight	Rocky Mountain
Gulf Conventional	Southwest
Gulf Shale	Southwest
Gulf Tight	Southwest
Permian Conventional	Southwest
Permian Shale	Southwest
Piceance Tight	Rocky Mountain
San Juan Coalbed Methane	Southwest
San Juan Shale	Southwest
South Oklahoma Shale	Southwest
Strawn Shale	Southwest
Uinta Conventional	Rocky Mountain
Uinta Tight	Rocky Mountain

Table C-5. GHG emissions intensity by techno-basin, production through transmission network boundary using U.S. average transmission data (g CO_2e/MJ, IPCC AR6-100 GWP)

Techno-basin	GHG Emissions Intensity (g CO_2e/MJ)
Alaska Offshore	6.99E+00
Anadarko Conv	1.62E+01
Anadarko Shale	9.68E+00
Anadarko Tight	1.17E+01
Appalachian Shale	6.41E+00
Arkla Conv	6.40E+00
Arkla Shale	6.39E+00
Arkla Tight	1.16E+01
Arkoma Conv	1.54E+01
Arkoma Shale	1.22E+01
East Texas Conv	7.70E+00
East Texas Shale	8.01E+00
East Texas Tight	7.74E+00
Fort Worth Shale	1.32E+01
GoM Offshore	6.20E+00
Green River Conv	1.28E+01
Green River Tight	1.32E+01
Gulf Conv	8.51E+00
Gulf Shale	7.44E+00
Gulf Tight	9.38E+00
Permian Conv	9.61E+00
Permian Shale	1.03E+01
Piceance Tight	8.55E+00
San Juan Coalbed Methane	1.77E+01
San Juan Shale	2.72E+01

Techno-basin	GHG Emissions Intensity (g CO_2e/MJ)
South Oklahoma Shale	8.64E+00
Strawn Shale	1.34E+01
Uinta Conv	3.44E+01
Uinta Tight	1.84E+01

Note: The GHG emissions intensity results are provided on a per MJ NG delivered, LHV basis. Results from the 2020 NETL Natural Gas Model were converted from HHV to LHV basis for this work.

Overall, Figure C-2 suggests that the NEMS-modeled changes in domestic natural gas production by region across the scenarios are not expected to significantly affect the projected GHG emissions intensities.

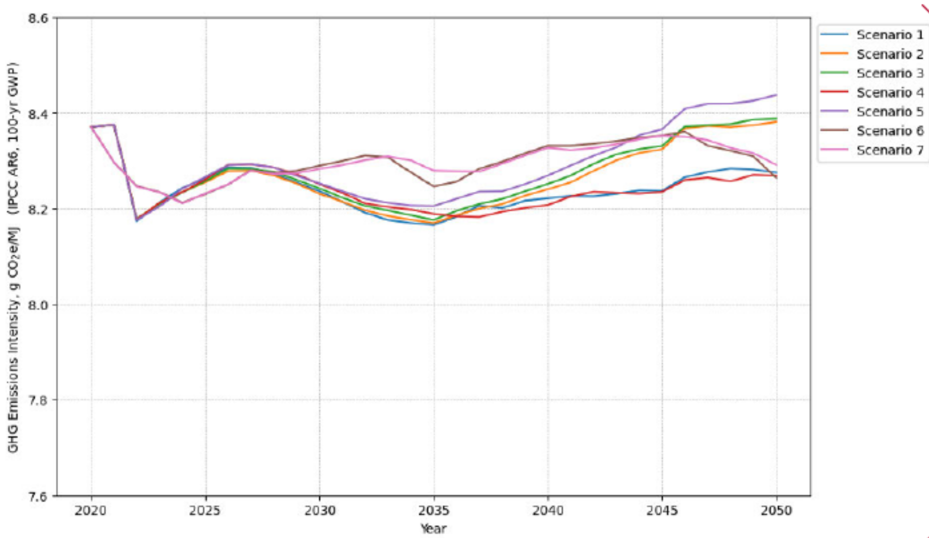

Figure C-2. Estimated U.S. average GHG intensity (g CO_2e/MJ) (S1–S7), production through transmission (2020–2050)

B. Data Inputs to LCA from GCAM

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 factors is relevant to this analysis (i.e., with a focus on the natural gas sector).

Results provided by PNNL for the various scenarios (1–7) and years modeled were provided as described in Table C-6, and were processed accordingly.

Commented [ST199]: NEMS includes endogenous learning. How much did the GHG emissions intensity of natural gas by region change in the model?

Should be different for S1 set versus S6/S7 set of model runs.

Commented [HK200]: Figure C-2 provides the variation in GHG emissions intensity as a function of changing regional NG production shares. It uses a constant set of techno-basin emission factors from the 2020 NG report (provided in Table C-5) and applies it across a range of production mixes over 30 years.

Commented [ST201]: Y axis, add "Emissions" and units and GWP version to label; U.S. Weighted Average GHG Emissions Intensity, g CO2e/MJ (IPCC AR6 100-yr GWP)

Commented [ST202]: Why does S4 have a steeper and lower GHG emissions intensity per unit of gas produced in 2050 than S6 or S7?

Commented [ST203]: Quantitative data discussion is needed to justify why the change is "not significant" and that domestic market effects can be ignored.

The data and conclusion show that a change occurs. Southwest (permian) gas increase. Permian is high GHG intense gas. Why is this not a market effect that needs to be considered?

GCAM shows a reduction in GHGs from exports.

NEMS shows an increase in GHGs from exports.

The scale/magnitude of the GCAM results are -5 and -3 g CO2e/MJ.

What is the equivalent sum over 35 years for the change between S2 and S1, and S7 and S6? The 2050 value change appears very small.

I think the conclusion that domestic changes are less significant compared to non-US global changes is valid.

However, I am concerned about saying there is "no" domestic market effect which is the outcome when we choose to not include domestic market effects in the analysis.

Commented [IGC204]: Note: GCAM is Global Change Analysis Model

Table C-6. 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 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, 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 and sectors along with specific technologies and years.
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.
Columns	**Description**
scenario	Scenario or context for which the data is provided such as "S1: Reference Exports," 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 CO_2 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 period for which the CO_2 emissions values are provided; this ranges from 2015 to 2050.
value	Corresponding CO_2 emissions values for the given combination of scenario, region, sector, subsector, technology, and year. The values represent the estimated or projected amount of CO_2 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 GHG that is being emitted. It identifies the specific type of gas responsible for the emissions, e.g., CH_4, N_2O, HFC125, C_2F_6, etc.
input	Additional details or characteristics about the technology or process.
output	Additional details or characteristics about the technology or process.

Commented [ST205]: Capitalization of column heading names seems to vary in this table. Intentional?

Commented [ST206]: Subscript

Commented [ST207]: Is this the column heading or column response?

C. GCAM and NETL Emissions Intensity Comparison

As noted in the main report, only three sectors of GCAM have information relevant to the upstream natural gas supply chain. The GCAM *gas pipeline* and *natural gas* sectors are assumed to wholly incorporate natural gas-relevant emissions, and so total emissions are extracted from GCAM output result files.

However, the *other industrial energy use* sector contains a diverse set of activities without explicitly representing emissions related to natural gas. GCAM incorporates a variety of data sources to represent activity in this sector. Relevant to natural gas activities for this sector, 2015 International Energy Agency (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, as in Table C-7. The provided data (not shown) details what percent of energy use in the sector was from the IEA energy flows (e.g., 25% of total sectoral energy use in a region from Extraction and Gathering and Boosting). As 99.5% of GHG emissions in the *other industrial energy use* sector are CO_2, only the IEA data source was used and only CO_2 data for that sector was adjusted.

Table C-7. LCA stage cross-mapping

NETL LCA Stage	IEA Energy Flow	GCAM Sector – Energy & CO_2
Extraction	Oil and Gas Extraction	other industrial energy use
Gathering and Boosting	Oil and Gas Extraction	other industrial energy use
Processing	Gas Works	other industrial energy use
Domestic Pipeline Transport	Pipeline Transport	gas pipeline
Liquefaction	LNG/Regasification Plants	other industrial energy use
Ocean Transport	International Marine Bunkers	trn_shipping_intl
Regasification	LNG/Regasification Plants	other industrial energy use
Pipeline Transport (at destination)	Pipeline Transport	gas pipeline

The 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 aggregated activities of extraction of both oil and gas resources. Given the lack of data on liquefaction and regasification in the 2015 IEA data (including for the United States), emissions from those activities are excluded from the analysis, consistent with the focus on upstream natural gas effects.

Commented [ST208]: What does this mean? Unclear.

The emissions intensity cells in Table C-7 show the underlying equation used to generate values on an AR6-100 basis, where the numerator is the total emissions from GCAM for the USA region for Scenario *S1* for the year 2020 for each of the three GHGs (if available), normalized by the total production of U.S. natural gas and oil from GCAM in 2020 (32.46 EJ and 22.46 EJ, respectively). Units of emissions intensity follow those internal to GCAM, which are Tg CO_2 equivalent/EJ, which conveniently are equal to g CO_2e/MJ, the same units as used in the NETL model. Thus, the bottom rows in Table C-8 show comparisons to those of the NETL model.

Table C-8. GCAM emissions intensities for sectors (S1, 2020, USA region, AR6-100 basis)

			Estimated GCAM Emissions Intensity (LHV) (Tg CO_2e/EJ, g CO_2e/MJ) [IPCC AR6-100]		
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 Natural Gas model.	38.0/32.5 = 1.17	-	-
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.	-	139.0/32.5 = 4.28	.015/32.5 = 4.5 E-4
other industrial energy use (technology = gas or gas cogen)[a]	For 2015, Extraction, Gathering & Boosting	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.	92.9/32.5 = 2.86	-	-
other industrial energy use (technology = refined liquids and refined liquids cogen)[a]			11/(32.5+22.5) = 0.2	-	-
other industrial energy use (electricity)[a]			-	-	-
Total GCAM by gas (LHV)			= 1.17 + 2.86 + .2 = 4.23	4.28	4.5 E-4
Total GCAM (LHV)			8.52		
Subtotal from NETL Model, Processing through Transmission boundary – LHV basis			8.18		
Adjustment factor (LHV)			8.18/8.52 = 0.96		

As implemented, this adjustment factor of 0.96 is directly applied to GHG emissions in all regions of the model for the *natural gas* and *gas pipeline* sectors as they wholly related to natural gas activities. By linearly scaling all regional values in this way, the existing and diverse CH_4 mitigation trends for each region in the underlying GCAM emissions factors for the *natural gas* sector were preserved by using this adjustment method.

Commented [ST209]: How was it preserved?

Does the MAF change every year (model time step) due to endogenous learning in the model?

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 in emissions associated with only natural gas activity 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 (i.e., it does not lead to a 4% reduction in emissions intensity for the other industrial energy use sector), it avoids the outcome where that sector's emissions are reduced for all of the other activities.

These adjustments to emissions from all regions, all scenarios, and all years were applied to existing GCAM results (i.e., GCAM was not re-run or scenarios optimized based on these adjustments).

Using the same detailed approach, Table C-9 through Table C-11 more succinctly summarize the provided GCAM values and adjustments identified for the IPCC AR6 values.

Table C-9. GCAM emissions intensities for sectors (S1, 2020, USA region, AR6-20 basis)

GCAM Sector	Estimated GCAM Emissions Intensity ($Tg\ CO_2e/EJ$, $g\ CO_2e/MJ$) [IPCC AR6-20]		
	CO_2	CH_4	N_2O
gas pipeline	1.17	-	-
natural gas	-	11.86	4.5 E-4
other industrial energy use (technology = gas or gas cogen)	2.86	-	-
other industrial energy use (technology = refined liquids and refined liquids cogen)	0.2	-	-
Total GCAM by gas (LHV)	= 1.17 + 2.86 + .2 = 4.23	11.86	4.5 E-4
Total GCAM (LHV)	16.1		
NETL (LHV basis)	13.8		
Adjustment Factor (LHV)	0.86		

Table C-10. GCAM emissions intensities for sectors (S1, 2020, USA region, AR5-100 basis)

GCAM Sector	Estimated GCAM Emissions Intensity ($Tg\ CO_2e/EJ$, $g\ CO_2e/MJ$) [IPCC AR5-100]		
	CO_2	CH_4	N_2O
gas pipeline	1.17	-	-
natural gas	-	5.18	4.9 E-4
other industrial energy use (technology = gas or gas cogen)	2.86	-	-
other industrial energy use (technology = refined liquids and refined liquids cogen)	0.2	-	-
Total GCAM by gas (LHV)	= 1.17 + 2.86 + .2 = 4.23	5.18	4.9 E-4
Total GCAM (LHV)	9.41		
NETL (LHV basis)	8.84		
Adjustment Factor (LHV)	0.94		

Table C-11. GCAM emissions intensities for sectors (S1, 2020, USA region, AR5-20 basis)

GCAM Sector	Estimated GCAM Emissions Intensity (Tg CO_2e/EJ, g CO_2e/MJ) [IPCC AR5-20]		
	CO_2	CH_4	N_2O
gas pipeline	1.17	-	-
natural gas	-	12.36	4.4 E-4
other industrial energy use (technology = gas or gas cogen)	2.86	-	-
other industrial energy use (technology = refined liquids and refined liquids cogen)	0.2	-	-
Total GCAM by gas (LHV)	= 1.17 + 2.86 + .2 = 4.23	12.36	4.4 E-4
Total GCAM (LHV)	16.6		
NETL (LHV basis)	14.2		
Adjustment Factor (LHV)	0.86		

Table C-12 shows the GWP of key GHGs that were used in conjunction with the emissions factors to derive the overall lifecycle GHG intensity.

Table C-12. GWP values used in this analysis

GHG	AR5-100 with ccf	AR5-20 with ccf	AR6-100	AR6-20
CH_4 (fossil)	36	86	29.8	82.5
CH_4 (non-fossil)	34	84	27.2	80.8
N_2O (fossil)	298	268	273	273
N_2O (non-fossil)	298	268	273	273
HFC125	3691	6207	3740	6740
HFC134a	1549	3789	1530	4140
HFC143a	5508	7064	5810	7840
HFC23	13856	11005	14600	12400
HFC32	817	2502	771	2690
SF_6	26087	17783	24300	18200
HFC245fa	1032	2992	962	3170
HFC365mfc	966	2724	914	2920
C_2F_6	12340	8344	12400	8940
CF_4	7349	4954	7380	5300
HFC43	1952	4403	1600	3960
HFC152a	167	524	164	591
HFC227ea	3860	3860	3600	5850
HFC236fa	8998	9810	8690	7450

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 16 GHGs and all are included in this study.

Market Adjustment Factors for Other IPCC GWP Values

Table C-13 shows all LHV and HHV MAF results for Scenario 2.

Table C-13. NETL-adjusted MAF results for S2

	Results (g CO_2e/MJ)				
MAF Case	AR5-100 with ccf	AR5-20 with ccf	AR6-100	AR6-20	Scenario Difference
***S2* vs. *S1* – unadjusted (LHV)**	-5.85	-9.17	-5.34	-8.86	Adds economic solution for LNG exports.
***S2* vs. *S1* – adjusted (LHV)**	-5.86	-9.12	-5.35	-8.74	
***S2* vs. *S1* – adjusted (HHV)**	-5.87	-8.98	-5.37	-8.67	

Table C-14 shows all LHV and HHV MAF results for *Scenario 7*.

Table C-14 NETL-adjusted MAF results for S7

	Results (g CO_2e/MJ)				
MAF Case	AR5-100 with ccf	AR5-20 with ccf	AR6-100	AR6-20	Scenario Difference
***S7* vs. *S6* – unadjusted (LHV)**	-3.54	-7.54	-3.01	-7.25	S6 1.5°C pathway, economic solution for LNG exports
***S7* vs. *S6* – adjusted (LHV)**	-3.44	-7.26	-2.95	-6.61	
***S7* vs. *S6* – adjusted (HHV)**	-3.29	-6.51	-2.81	-6.27	

Tables D-32 through D-39 in the Appendix show the underlying annual CO_2e emissions and U.S. LNG export volumes used in the MAF calculations above. Cumulative MAF values are calculated by finding the running sum of delta values from 2015 to the current year for both LNG export volumes and global GHG emissions, and the cumulative values for 2050 match those shown above in the report.

Commented [ST210]: I expected to find the index of country GHG emissions intensity to show the relative differences before and after adjustment.

I also expected to see more detail on "what" changed within each countries energy portfolio as a result of increased US LNG exports.

There is a larger "report" decision that will need to be made regarding additional transparency needed to support the conclusions.

This would be more in-line with the expectations described in the August 17, 2023 email to Scott/Matt from Tim.

NO ACTION REQUIRED AT THIS TIME UNTIL FURTHE REPORT WIDE GUIDANCE ON TRANSPARNCY/LEVEL OF DETAIL PROVIDED

APPENDIX D: TABULATED VALUES FROM FIGURES

Table D-1. U.S. LNG exports across the scenarios, tabulated by year (see Figure 3)

Scenario	Unit	2015	2020	2025	2030	2035	2040	2045	2050
S1	Bcf/d	0.05	7.03	13.33	18.85	25.98	27.33	27.33	27.33
S2	Bcf/d	0.05	7.03	13.33	18.85	24.87	34.84	42.86	47.23
S3	Bcf/d	0.05	7.03	13.33	18.84	25.22	35.47	43.91	48.74
S4	Bcf/d	0.05	7.03	13.33	12.15	13.26	15.22	19.81	23.06
S5	Bcf/d	0.05	7.03	13.33	18.85	24.94	34.89	42.69	47.18
S6	Bcf/d	0.05	7.03	13.33	14.75	18.68	25.79	27.33	27.33
S7	Bcf/d	0.05	7.03	13.33	14.75	18.68	25.79	31.37	33.59
S1–S1	Bcf/d	0	0	0	0	0	0	0	0
S2–S1	Bcf/d	0	0	0	0	-1.1	7.51	15.52	19.9
S3–S1	Bcf/d	0	0	0	-0.01	-0.75	8.14	16.58	21.41
S4–S1	Bcf/d	0	0	0	-6.71	-12.71	-12.11	-7.53	-4.27
S5–S1	Bcf/d	0	0	0	0	-1.04	7.56	15.35	19.84
S6–S1	Bcf/d	0	0	0	-4.1	-7.29	-1.54	0	0
S7–S1	Bcf/d	0	0	0	-4.1	-7.29	-1.54	4.03	6.25
S1–S1	%	0	0	0	0	0	0	0	0
S2–S1	%	0	0	0	0	-4.2	27.5	56.8	72.8
S3–S1	%	0	0	0	0	-2.9	29.8	60.6	78.3
S4–S1	%	0	0	0	-35.6	-48.9	-44.3	-27.5	-15.6
S5–S1	%	0	0	0	0	-4	27.6	56.2	72.6
S6–S1	%	0	0	0	-21.7	-28.1	-5.6	0	0
S7–S1	%	0	0	0	-21.7	-28.1	-5.6	14.8	22.9

Table D-2. Natural gas consumption, production, and trade by region under S1 and S2 (see Figure 4) and changes in natural gas consumption, production, and trade by region in S2 vs. S1 (see Figure 5)

Scenario	Region	Unit	NG Volumes	2015	2020	2025	2030	2035	2040	2045	2050
S1	ROW	Bcf/d	Consumption	36.63	42.29	40.4	45.44	48.91	50.95	53.93	55.91
	Australia + NZ	Bcf/d	Consumption	3.85	0.79	0.31	0.43	0.38	0.51	0.76	1.11
	LAC	Bcf/d	Consumption	16.2	17.55	16.48	19.77	23.42	26.72	30.13	33.06
	Africa	Bcf/d	Consumption	12.32	14.45	14.21	17.09	21.45	26.78	33.49	41.44
	C Asia + East Eur	Bcf/d	Consumption	23.97	28.95	30.4	32.56	35.76	39.02	42.05	44.38
	Russia	Bcf/d	Consumption	41.18	45.82	35.98	39.62	39.94	39.92	39.91	39.81
	China	Bcf/d	Consumption	17.41	27.43	41.41	47.78	55.34	61.76	68.74	73.96
	India	Bcf/d	Consumption	5.07	7.96	11.89	17.19	22.88	28.35	34.63	41.12
	Middle East	Bcf/d	Consumption	44.96	46.53	46.04	47.58	51.74	56.93	63.16	67.9
	EU	Bcf/d	Consumption	40.32	48.18	35.83	33.46	29.99	28.83	32.7	36.46
	Mexico	Bcf/d	Consumption	6.91	8.28	8.06	9.36	10.7	12.08	13.4	14.74
	Canada	Bcf/d	Consumption	10.91	11.44	7.98	8.3	7.89	7.46	6.82	5.98
	USA	Bcf/d	Consumption	71.81	80.43	82.48	87.93	90.3	95.39	106.72	119
		Bcf/d	Total	331.53	380.11	371.45	406.51	438.72	474.7	526.45	574.88
	ROW	Bcf/d	Production	36.73	41.02	37.93	43.12	45.75	46.59	47.87	48.66
	Australia + NZ	Bcf/d	Production	6.84	12.71	12.21	12.11	11.09	9.61	7.82	6.59
	LAC	Bcf/d	Production	16.56	15.44	13.76	15.88	17.84	19.94	22.71	25.42
	Africa	Bcf/d	Production	18.43	23.83	24.67	27.6	31.5	36.6	42.46	48.39
	C Asia + East Eur	Bcf/d	Production	23.23	17.31	17.56	18.75	20.56	23.38	26.73	30.13
	Russia	Bcf/d	Production	58.04	70.26	59.82	63.01	63.57	67.82	74.16	80.12
	China	Bcf/d	Production	12.49	16.74	19.82	22.5	24.88	26.36	27.6	28.26
	India	Bcf/d	Production	2.89	4.02	4.91	7.13	9.9	13.37	17.64	22.27
	Middle East	Bcf/d	Production	55	59.51	58.6	60.95	66.4	73	81.24	87.94
	EU	Bcf/d	Production	11.72	13.69	10.05	10.19	9.82	10.22	15.81	20.86
	Mexico	Bcf/d	Production	3.8	3.21	2.55	3.35	3.91	4.48	5.36	6.46
	Canada	Bcf/d	Production	15.4	15.11	14.05	14.59	15.24	16.86	18.23	18.12
	USA	Bcf/d	Production	70.47	87.25	95.51	107.34	118.25	126.46	138.82	151.65
		Bcf/d	Total	331.61	380.11	371.45	406.51	438.72	474.69	526.45	574.88
	ROW	Bcf/d	LNG exports	8.59	10.56	11.11	13.82	15.57	16.43	18.02	19.15
	Australia + NZ	Bcf/d	LNG exports	3.02	11.93	11.9	11.69	10.72	9.11	7.07	5.66

Scenario	Region	Unit	NG Volumes	2015	2020	2025	2030	2035	2040	2045	2050
	LAC	Bcf/d	LNG exports	1.82	1.83	2.2	2.67	3.51	4.71	6.27	7.61
	Africa	Bcf/d	LNG exports	5.56	9.09	10.65	11.58	12.46	13.6	14.77	15.28
	C Asia + East Eur	Bcf/d	LNG exports	0.02	0.06	0.17	0.42	1.07	2.52	4.88	7.51
	Russia	Bcf/d	LNG exports	1.64	3.05	3.82	3.9	3.67	3.34	3.25	3.47
	China	Bcf/d	LNG exports	0	0	0	0.01	0.02	0.06	0.11	0.15
	India	Bcf/d	LNG exports	0.05	0.01	0.01	0.04	0.09	0.2	0.41	0.64
	Middle East	Bcf/d	LNG exports	10.41	13.4	13.05	14	15.75	17.71	20.44	22.91
	EU	Bcf/d	LNG exports	0.71	0.37	0.46	0.63	0.87	1.68	3.17	4.5
	Mexico	Bcf/d	LNG exports	0	0	0	0.01	0.03	0.09	0.2	0.34
	Canada	Bcf/d	LNG exports	0	0.01	2.01	2.65	4.39	7.38	10.05	11.15
	USA	Bcf/d	LNG exports	0.05	7.03	13.33	18.85	25.98	27.33	27.33	27.33
		Bcf/d	Total	0	57.34	68.72	80.27	94.13	104.15	115.98	125.71
	ROW	Bcf/d	LNG imports	18.06	20.88	20.26	22.28	23.89	24.6	25.95	26.95
	Australia + NZ	Bcf/d	LNG imports	0.03	0.01	0	0	0	0	0.01	0.18
	LAC	Bcf/d	LNG imports	2.26	3.94	4.92	6.56	9.09	11.49	13.69	15.24
	Africa	Bcf/d	LNG imports	0.67	0.97	1.16	1.95	3.14	4.32	6.08	8.44
	C Asia + East Eur	Bcf/d	LNG imports	3.91	6.4	7.97	9.15	11.15	12.55	13.61	14.19
	Russia	Bcf/d	LNG imports	0	0.82	0.68	0.81	1.82	2.62	3.13	3.33
	China	Bcf/d	LNG imports	2.62	6.98	15.66	17.75	19.34	19.68	19.85	19.88
	India	Bcf/d	LNG imports	2.24	3.95	7	10.1	13.08	15.18	17.39	19.5
	Middle East	Bcf/d	LNG imports	0.37	0.43	0.48	0.63	1.07	1.54	2.13	2.52
	EU	Bcf/d	LNG imports	4.98	11.32	8.86	9.21	9.65	10.24	12.01	13.18
	Mexico	Bcf/d	LNG imports	0.73	1.15	1.34	1.44	1.57	1.64	1.77	1.95
	Canada	Bcf/d	LNG imports	0.18	0.21	0.15	0.15	0.14	0.19	0.25	0.26
	USA	Bcf/d	LNG imports	0.27	0.26	0.26	0.23	0.18	0.1	0.1	0.1
		Bcf/d	Total	36.32	57.34	68.72	80.27	94.13	104.15	115.98	125.71
	ROW	Bcf/d	Pipeline exports	10.37	10.05	7.51	7.05	6.05	4.62	2.67	1.52
	Australia + NZ	Bcf/d	Pipeline exports	0	0	0	0	0	0	0	0
	LAC	Bcf/d	Pipeline exports	2.15	2.11	1.82	1.79	1.6	1.36	1.22	1.23
	Africa	Bcf/d	Pipeline exports	1.36	1.42	1.13	1.23	1.58	2.35	3.38	4.8
	C Asia + East Eur	Bcf/d	Pipeline exports	7.81	0.07	0.05	0.05	0.04	0.03	0.01	0.01
	Russia	Bcf/d	Pipeline exports	14.83	23.46	21.67	21.37	23.15	29.3	37.12	43.78
	China	Bcf/d	Pipeline exports	0	0	0	0	0	0	0	0
	India	Bcf/d	Pipeline exports	0	0	0	0	0	0	0	0
	Middle East	Bcf/d	Pipeline exports	0.03	0.03	0.02	0.03	0.03	0.04	0.06	0.09
	EU	Bcf/d	Pipeline exports	2.36	2.21	1.61	1.49	1.25	0.92	0.49	0.27
	Mexico	Bcf/d	Pipeline exports	0.01	0.01	0	0.01	0.05	0.15	0.35	0.56
	Canada	Bcf/d	Pipeline exports	5.97	6.23	5.87	5.51	4.76	3.97	3.3	2.81
	USA	Bcf/d	Pipeline exports	5.17	8.53	8.53	8.53	8.53	8.52	8.53	8.53
		Bcf/d	Total	50.07	54.11	48.21	47.06	47.04	51.26	57.14	63.59
	ROW	Bcf/d	Pipeline imports	1.01	1	0.83	0.91	0.88	0.8	0.8	0.98
	Australia + NZ	Bcf/d	Pipeline imports	0	0	0	0	0	0	0	0
	LAC	Bcf/d	Pipeline imports	2.15	2.11	1.82	1.79	1.6	1.36	1.22	1.23
	Africa	Bcf/d	Pipeline imports	0.14	0.15	0.16	0.35	0.84	1.81	3.11	4.68
	C Asia + East Eur	Bcf/d	Pipeline imports	5.58	5.37	5.09	5.13	5.17	5.64	6.61	7.59
	Russia	Bcf/d	Pipeline imports	1.11	1.25	0.97	1.08	1.37	2.12	3	3.62
	China	Bcf/d	Pipeline imports	2.29	3.7	5.93	7.54	11.14	15.78	21.4	25.97
	India	Bcf/d	Pipeline imports	0	0	0	0	0	0	0	0
	Middle East	Bcf/d	Pipeline imports	0.05	0.02	0.03	0.03	0.06	0.14	0.29	0.45
	EU	Bcf/d	Pipeline imports	26.7	25.74	18.99	16.18	12.65	10.96	8.54	7.18
	Mexico	Bcf/d	Pipeline imports	2.39	3.93	4.18	4.6	5.29	6.2	6.81	7.23
	Canada	Bcf/d	Pipeline imports	2.06	2.35	1.66	1.72	1.66	1.75	1.7	1.56
	USA	Bcf/d	Pipeline imports	7.74	8.48	8.56	7.73	6.38	4.7	3.67	3.11
		Bcf/d	Total	51.21	54.11	48.21	47.06	47.04	51.27	57.14	63.59
	ROW	Bcf/d	Consumption	36.63	42.29	40.4	45.44	48.76	51.9	55.46	57.76
	Australia + NZ	Bcf/d	Consumption	3.85	0.79	0.31	0.43	0.37	0.52	0.78	1.13
	LAC	Bcf/d	Consumption	16.2	17.55	16.48	19.77	23.34	27.29	30.97	33.98
S2	Africa	Bcf/d	Consumption	12.32	14.45	14.21	17.09	21.44	26.94	33.87	42
	C Asia + East Eur	Bcf/d	Consumption	23.97	28.95	30.4	32.56	35.69	39.41	42.46	44.78
	Russia	Bcf/d	Consumption	41.18	45.82	35.98	39.62	39.93	39.98	39.98	39.88
	China	Bcf/d	Consumption	17.41	27.43	41.41	47.78	55.04	62.68	69.41	74.51
	India	Bcf/d	Consumption	5.07	7.96	11.89	17.19	22.78	28.94	35.5	42.11

Scenario	Region	Unit	NG Volumes	2015	2020	2025	2030	2035	2040	2045	2050
	Middle East	Bcf/d	Consumption	44.96	46.53	46.04	47.58	51.75	56.89	63.14	67.95
	EU	Bcf/d	Consumption	40.32	48.18	35.83	33.46	29.54	30.59	34.25	37.95
	Mexico	Bcf/d	Consumption	6.91	8.28	8.06	9.36	10.7	12.08	13.42	14.76
	Canada	Bcf/d	Consumption	10.91	11.44	7.98	8.3	7.9	7.47	6.92	6.11
	USA	Bcf/d	Consumption	71.81	80.43	82.48	87.93	90.36	94.97	105.54	115.78
		Bcf/d	Total	331.53	380.11	371.45	406.51	437.59	479.66	531.68	578.69
	ROW	Bcf/d	Production	36.73	41.02	37.93	43.12	45.71	46.36	47.03	47.63
	Australia + NZ	Bcf/d	Production	6.84	12.71	12.21	12.11	11.09	9.58	7.65	6.24
	LAC	Bcf/d	Production	16.56	15.44	13.76	15.88	17.88	19.55	21.78	24.2
	Africa	Bcf/d	Production	18.43	23.83	24.67	27.6	31.53	36.13	41.24	46.78
	C Asia + East Eur	Bcf/d	Production	23.23	17.31	17.56	18.75	20.59	23.12	25.9	28.85
	Russia	Bcf/d	Production	58.04	70.26	59.82	63.01	63.59	67.37	72.53	77.91
	China	Bcf/d	Production	12.49	16.74	19.82	22.5	24.83	26.5	27.57	28.17
	India	Bcf/d	Production	2.89	4.02	4.91	7.13	9.92	13.25	17.23	21.64
	Middle East	Bcf/d	Production	55	59.51	58.6	60.95	66.41	72.45	79.54	85.59
	EU	Bcf/d	Production	11.72	13.69	10.05	10.19	9.67	10.83	15.39	19.98
	Mexico	Bcf/d	Production	3.8	3.21	2.55	3.35	3.91	4.48	5.31	6.4
	Canada	Bcf/d	Production	15.4	15.11	14.05	14.59	15.23	16.78	17.78	17.52
	USA	Bcf/d	Production	70.47	87.25	95.51	107.34	117.24	133.28	152.75	167.78
		Bcf/d	Total	331.61	380.11	371.45	406.51	437.59	479.66	531.68	578.69
	ROW	Bcf/d	LNG exports	8.59	10.56	11.11	13.82	15.59	16.26	17.28	18.13
	Australia + NZ	Bcf/d	LNG exports	3.02	11.93	11.9	11.69	10.72	9.06	6.88	5.32
	LAC	Bcf/d	LNG exports	1.82	1.83	2.2	2.67	3.5	4.63	5.9	7.03
	Africa	Bcf/d	LNG exports	5.56	9.09	10.65	11.58	12.46	13.43	14.04	14.24
	C Asia + East Eur	Bcf/d	LNG exports	0.02	0.06	0.17	0.42	1.07	2.45	4.37	6.58
	Russia	Bcf/d	LNG exports	1.64	3.05	3.82	3.9	3.67	3.3	3.07	3.14
	China	Bcf/d	LNG exports	0	0	0	0.01	0.02	0.05	0.09	0.13
	India	Bcf/d	LNG exports	0.05	0.01	0.01	0.04	0.09	0.19	0.36	0.55
	Middle East	Bcf/d	LNG exports	10.41	13.4	13.05	14	15.71	17.51	19.25	21.03
	EU	Bcf/d	LNG exports	0.71	0.37	0.46	0.63	0.87	1.6	2.79	3.93
	Mexico	Bcf/d	LNG exports	0	0	0	0.01	0.03	0.08	0.17	0.29
	Canada	Bcf/d	LNG exports	0	0.01	2.01	2.65	4.38	7.26	9.47	10.36
	USA	Bcf/d	LNG exports	0.05	7.03	13.33	18.85	24.87	34.84	42.86	47.23
		Bcf/d	Total	0	57.34	68.72	80.27	92.98	110.68	126.53	137.96
	ROW	Bcf/d	LNG imports	18.06	20.88	20.26	22.28	23.73	25.6	27.58	28.82
	Australia + NZ	Bcf/d	LNG imports	0.03	0.01	0	0	0	0	0.01	0.21
	LAC	Bcf/d	LNG imports	2.26	3.94	4.92	6.56	8.96	12.38	15.09	16.82
	Africa	Bcf/d	LNG imports	0.67	0.97	1.16	1.95	3.09	4.78	6.95	9.58
	C Asia + East Eur	Bcf/d	LNG imports	3.91	6.4	7.97	9.15	11.01	13.37	14.88	15.6
	Russia	Bcf/d	LNG imports	0	0.82	0.68	0.81	1.76	2.97	3.72	3.98
	China	Bcf/d	LNG imports	2.62	6.98	15.66	17.75	19.14	20.33	20.86	21.03
	India	Bcf/d	LNG imports	2.24	3.95	7	10.1	12.94	15.88	18.63	21.02
	Middle East	Bcf/d	LNG imports	0.37	0.43	0.48	0.63	1.03	1.87	2.67	3.1
	EU	Bcf/d	LNG imports	4.98	11.32	8.86	9.21	9.44	11.34	13.61	14.99
	Mexico	Bcf/d	LNG imports	0.73	1.15	1.34	1.44	1.56	1.77	2.02	2.27
	Canada	Bcf/d	LNG imports	0.18	0.21	0.15	0.15	0.14	0.25	0.35	0.37
	USA	Bcf/d	LNG imports	0.27	0.26	0.26	0.23	0.17	0.15	0.16	0.17
		Bcf/d	Total	36.32	57.34	68.72	80.27	92.98	110.68	126.53	137.96
	ROW	Bcf/d	Pipeline exports	10.37	10.05	7.51	7.05	5.97	4.59	2.65	1.5
	Australia + NZ	Bcf/d	Pipeline exports	0	0	0	0	0	0	0	0
	LAC	Bcf/d	Pipeline exports	2.15	2.11	1.82	1.79	1.61	1.3	1.12	1.1
	Africa	Bcf/d	Pipeline exports	1.36	1.42	1.13	1.23	1.58	2.25	3.18	4.52
	C Asia + East Eur	Bcf/d	Pipeline exports	7.81	0.07	0.05	0.05	0.04	0.03	0.01	0.01
	Russia	Bcf/d	Pipeline exports	14.83	23.46	21.67	21.37	23.14	29.04	35.93	42.16
	China	Bcf/d	Pipeline exports	0	0	0	0	0	0	0	0
	India	Bcf/d	Pipeline exports	0	0	0	0	0	0	0	0
	Middle East	Bcf/d	Pipeline exports	0.03	0.03	0.02	0.03	0.03	0.04	0.06	0.08
	EU	Bcf/d	Pipeline exports	2.36	2.21	1.61	1.49	1.23	0.92	0.48	0.25
	Mexico	Bcf/d	Pipeline exports	0.01	0.01	0	0.01	0.05	0.15	0.35	0.58
	Canada	Bcf/d	Pipeline exports	5.97	6.23	5.87	5.51	4.76	3.99	3.36	2.9
	USA	Bcf/d	Pipeline exports	5.17	8.53	8.53	8.53	8.53	8.53	8.53	8.53
		Bcf/d	Total	50.07	54.11	48.21	47.06	46.94	50.82	55.66	61.63

Scenario	Region	Unit	NG Volumes	2015	2020	2025	2030	2035	2040	2045	2050
	ROW	Bcf/d	Pipeline imports	1.01	1	0.83	0.91	0.88	0.8	0.78	0.93
	Australia + NZ	Bcf/d	Pipeline imports	0	0	0	0	0	0	0	0
	LAC	Bcf/d	Pipeline imports	2.15	2.11	1.82	1.79	1.61	1.3	1.12	1.1
	Africa	Bcf/d	Pipeline imports	0.14	0.15	0.16	0.35	0.86	1.71	2.9	4.41
	C Asia + East Eur	Bcf/d	Pipeline imports	5.58	5.37	5.09	5.13	5.2	5.4	6.06	6.92
	Russia	Bcf/d	Pipeline imports	1.11	1.25	0.97	1.08	1.38	1.98	2.73	3.29
	China	Bcf/d	Pipeline imports	2.29	3.7	5.93	7.54	11.09	15.91	21.06	25.44
	India	Bcf/d	Pipeline imports	0	0	0	0	0	0	0	0
	Middle East	Bcf/d	Pipeline imports	0.05	0.02	0.03	0.03	0.06	0.12	0.24	0.37
	EU	Bcf/d	Pipeline imports	26.7	25.74	18.99	16.18	12.53	10.94	8.53	7.16
	Mexico	Bcf/d	Pipeline imports	2.39	3.93	4.18	4.6	5.32	6.07	6.6	6.94
	Canada	Bcf/d	Pipeline imports	2.06	2.35	1.66	1.72	1.67	1.69	1.62	1.47
	USA	Bcf/d	Pipeline imports	7.74	8.48	8.56	7.73	6.35	4.91	4.02	3.59
		Bcf/d	Total	51.21	54.11	48.21	47.06	46.94	50.82	55.66	61.63
S2–S1	ROW	Bcf/d	Consumption	0	0	0	0	-0.14	0.95	1.53	1.84
	Australia + NZ	Bcf/d	Consumption	0	0	0	0	0	0.01	0.02	0.02
	LAC	Bcf/d	Consumption	0	0	0	0	-0.08	0.57	0.84	0.93
	Africa	Bcf/d	Consumption	0	0	0	0	-0.02	0.16	0.37	0.56
	C Asia + East Eur	Bcf/d	Consumption	0	0	0	0	-0.08	0.4	0.41	0.4
	Russia	Bcf/d	Consumption	0	0	0	0	-0.02	0.07	0.07	0.07
	China	Bcf/d	Consumption	0	0	0	0	-0.3	0.92	0.67	0.55
	India	Bcf/d	Consumption	0	0	0	0	-0.11	0.59	0.87	0.98
	Middle East	Bcf/d	Consumption	0	0	0	0	0.01	-0.04	-0.02	0.04
	EU	Bcf/d	Consumption	0	0	0	0	-0.46	1.75	1.56	1.49
	Mexico	Bcf/d	Consumption	0	0	0	0	0	-0.01	0.02	0.02
	Canada	Bcf/d	Consumption	0	0	0	0	0	0.01	0.1	0.13
	USA	Bcf/d	Consumption	0	0	0	0	0.06	-0.43	-1.19	-3.22
		Bcf/d	Total	0	0	0	0	-1.13	4.96	5.24	3.82
	ROW	Bcf/d	Production	0	0	0	0	-0.05	-0.23	-0.85	-1.03
	Australia + NZ	Bcf/d	Production	0	0	0	0	0	-0.03	-0.17	-0.35
	LAC	Bcf/d	Production	0	0	0	0	0.05	-0.39	-0.93	-1.22
	Africa	Bcf/d	Production	0	0	0	0	0.02	-0.47	-1.22	-1.61
	C Asia + East Eur	Bcf/d	Production	0	0	0	0	0.03	-0.26	-0.83	-1.28
	Russia	Bcf/d	Production	0	0	0	0	0.02	-0.44	-1.63	-2.22
	China	Bcf/d	Production	0	0	0	0	-0.05	0.14	-0.03	-0.09
	India	Bcf/d	Production	0	0	0	0	0.03	-0.12	-0.41	-0.63
	Middle East	Bcf/d	Production	0	0	0	0	0.01	-0.55	-1.7	-2.35
	EU	Bcf/d	Production	0	0	0	0	-0.15	0.61	-0.42	-0.88
	Mexico	Bcf/d	Production	0	0	0	0	0	-0.01	-0.05	-0.05
	Canada	Bcf/d	Production	0	0	0	0	-0.01	-0.09	-0.45	-0.6
	USA	Bcf/d	Production	0	0	0	0	-1.01	6.82	13.93	16.13
		Bcf/d	Total	0	0	0	0	-1.13	4.97	5.24	3.82
	ROW	Bcf/d	LNG exports	0	0	0	0	0.02	-0.16	-0.75	-1.02
	Australia + NZ	Bcf/d	LNG exports	0	0	0	0	0	-0.04	-0.18	-0.34
	LAC	Bcf/d	LNG exports	0	0	0	0	-0.01	-0.08	-0.37	-0.57
	Africa	Bcf/d	LNG exports	0	0	0	0	-0.01	-0.17	-0.72	-1.03
	C Asia + East Eur	Bcf/d	LNG exports	0	0	0	0	0	-0.08	-0.51	-0.93
	Russia	Bcf/d	LNG exports	0	0	0	0	0	-0.03	-0.19	-0.34
	China	Bcf/d	LNG exports	0	0	0	0	0	0	-0.02	-0.03
	India	Bcf/d	LNG exports	0	0	0	0	0	-0.01	-0.05	-0.09
	Middle East	Bcf/d	LNG exports	0	0	0	0	-0.04	-0.2	-1.19	-1.88
	EU	Bcf/d	LNG exports	0	0	0	0	0	-0.07	-0.38	-0.56
	Mexico	Bcf/d	LNG exports	0	0	0	0	0	-0.01	-0.03	-0.05
	Canada	Bcf/d	LNG exports	0	0	0	0	-0.01	-0.12	-0.58	-0.79
	USA	Bcf/d	LNG exports	0	0	0	0	-1.1	7.51	15.52	19.9
		Bcf/d	Total	0	0	0	0	-1.15	6.53	10.55	12.25
	ROW	Bcf/d	LNG imports	0	0	0	0	-0.16	0.99	1.62	1.87
	Australia + NZ	Bcf/d	LNG imports	0	0	0	0	0	0	0.01	0.03
	LAC	Bcf/d	LNG imports	0	0	0	0	-0.13	0.89	1.39	1.57
	Africa	Bcf/d	LNG imports	0	0	0	0	-0.06	0.46	0.87	1.14
	C Asia + East Eur	Bcf/d	LNG imports	0	0	0	0	-0.14	0.83	1.27	1.42
	Russia	Bcf/d	LNG imports	0	0	0	0	-0.06	0.35	0.59	0.65

Scenario	Region	Unit	NG Volumes	2015	2020	2025	2030	2035	2040	2045	2050
	China	Bcf/d	LNG imports	0	0	0	0	-0.2	0.65	1.02	1.15
	India	Bcf/d	LNG imports	0	0	0	0	-0.13	0.7	1.23	1.52
	Middle East	Bcf/d	LNG imports	0	0	0	0	-0.04	0.33	0.54	0.58
	EU	Bcf/d	LNG imports	0	0	0	0	-0.21	1.09	1.6	1.81
	Mexico	Bcf/d	LNG imports	0	0	0	0	-0.02	0.13	0.25	0.33
	Canada	Bcf/d	LNG imports	0	0	0	0	0	0.06	0.1	0.11
	USA	Bcf/d	LNG imports	0	0	0	0	-0.01	0.05	0.06	0.07
		Bcf/d	**Total**	**0**	**0**	**0**	**0**	**-1.15**	**6.53**	**10.55**	**12.25**
	ROW	Bcf/d	Pipeline exports	0	0	0	0	-0.08	-0.03	-0.02	-0.03
	Australia + NZ	Bcf/d	Pipeline exports	0	0	0	0	0	0	0	0
	LAC	Bcf/d	Pipeline exports	0	0	0	0	0.01	-0.06	-0.1	-0.12
	Africa	Bcf/d	Pipeline exports	0	0	0	0	0	-0.1	-0.2	-0.28
	C Asia + East Eur	Bcf/d	Pipeline exports	0	0	0	0	0	0	0	0
	Russia	Bcf/d	Pipeline exports	0	0	0	0	-0.01	-0.26	-1.2	-1.62
	China	Bcf/d	Pipeline exports	0	0	0	0	0	0	0	0
	India	Bcf/d	Pipeline exports	0	0	0	0	0	0	0	0
	Middle East	Bcf/d	Pipeline exports	0	0	0	0	0	0	0	-0.01
	EU	Bcf/d	Pipeline exports	0	0	0	0	-0.02	0	-0.01	-0.01
	Mexico	Bcf/d	Pipeline exports	0	0	0	0	0	0	0	0.02
	Canada	Bcf/d	Pipeline exports	0	0	0	0	0	0.02	0.06	0.09
	USA	Bcf/d	Pipeline exports	0	0	0	0	0	0	0	0
		Bcf/d	**Total**	**0**	**0**	**0**	**0**	**-0.1**	**-0.43**	**-1.49**	**-1.95**
	ROW	Bcf/d	Pipeline imports	0	0	0	0	0	-0.01	-0.02	-0.05
	Australia + NZ	Bcf/d	Pipeline imports	0	0	0	0	0	0	0	0
	LAC	Bcf/d	Pipeline imports	0	0	0	0	0.01	-0.06	-0.1	-0.12
	Africa	Bcf/d	Pipeline imports	0	0	0	0	0.01	-0.11	-0.2	-0.28
	C Asia + East Eur	Bcf/d	Pipeline imports	0	0	0	0	0.03	-0.24	-0.54	-0.67
	Russia	Bcf/d	Pipeline imports	0	0	0	0	0.01	-0.14	-0.27	-0.32
	China	Bcf/d	Pipeline imports	0	0	0	0	-0.06	0.13	-0.34	-0.53
	India	Bcf/d	Pipeline imports	0	0	0	0	0	0	0	0
	Middle East	Bcf/d	Pipeline imports	0	0	0	0	0	-0.02	-0.05	-0.08
	EU	Bcf/d	Pipeline imports	0	0	0	0	-0.12	-0.02	-0.01	-0.01
	Mexico	Bcf/d	Pipeline imports	0	0	0	0	0.02	-0.13	-0.21	-0.29
	Canada	Bcf/d	Pipeline imports	0	0	0	0	0	-0.06	-0.08	-0.09
	USA	Bcf/d	Pipeline imports	0	0	0	0	-0.03	0.21	0.35	0.48
		Bcf/d	**Total**	**0**	**0**	**0**	**0**	**-0.1**	**-0.44**	**-1.49**	**-1.95**
	ROW	%	Consumption	0	0	0	0	-0.29	1.87	2.83	3.3
	Australia + NZ	%	Consumption	0	0	0	0	-0.47	1.88	2.45	1.6
	LAC	%	Consumption	0	0	0	0	-0.34	2.13	2.77	2.8
	Africa	%	Consumption	0	0	0	0	-0.07	0.6	1.12	1.36
	C Asia + East Eur	%	Consumption	0	0	0	0	-0.21	1.02	0.98	0.9
	Russia	%	Consumption	0	0	0	0	-0.05	0.17	0.17	0.17
	China	%	Consumption	0	0	0	0	-0.54	1.5	0.97	0.75
	India	%	Consumption	0	0	0	0	-0.47	2.06	2.5	2.39
	Middle East	%	Consumption	0	0	0	0	0.02	-0.06	-0.03	0.06
	EU	%	Consumption	0	0	0	0	-1.52	6.08	4.77	4.1
	Mexico	%	Consumption	0	0	0	0	0.03	-0.05	0.17	0.12
	Canada	%	Consumption	0	0	0	0	0.05	0.11	1.42	2.19
	USA	%	Consumption	0	0	0	0	0.07	-0.45	-1.11	-2.71
		%	**Total**	**0**	**0**	**0**	**0**	**-3.82**	**16.87**	**19**	**17.03**
	ROW	%	Production	0	0	0	0	-0.1	-0.49	-1.77	-2.11
	Australia + NZ	%	Production	0	0	0	0	-0.04	-0.34	-2.2	-5.37
	LAC	%	Production	0	0	0	0	0.26	-1.96	-4.11	-4.79
	Africa	%	Production	0	0	0	0	0.08	-1.29	-2.87	-3.34
	C Asia + East Eur	%	Production	0	0	0	0	0.12	-1.12	-3.1	-4.26
	Russia	%	Production	0	0	0	0	0.02	-0.66	-2.2	-2.76
	China	%	Production	0	0	0	0	-0.18	0.54	-0.12	-0.31
	India	%	Production	0	0	0	0	0.26	-0.91	-2.35	-2.83
	Middle East	%	Production	0	0	0	0	0.01	-0.75	-2.09	-2.67
	EU	%	Production	0	0	0	0	-1.54	5.92	-2.64	-4.21
	Mexico	%	Production	0	0	0	0	-0.05	-0.18	-0.85	-0.85
	Canada	%	Production	0	0	0	0	-0.07	-0.51	-2.47	-3.3

Scenario	Region	Unit	NG Volumes	2015	2020	2025	2030	2035	2040	2045	2050
	USA	%	Production	0	0	0	0	-0.85	5.39	10.03	10.63
		%	Total	0	0	0	0	-2.09	3.64	-16.74	-26.16
	ROW	%	LNG exports	0	0	0	0	0.14	-1	-4.15	-5.33
	Australia + NZ	%	LNG exports	0	0	0	0	-0.02	-0.47	-2.61	-6.07
	LAC	%	LNG exports	0	0	0	0	-0.24	-1.61	-5.96	-7.51
	Africa	%	LNG exports	0	0	0	0	-0.05	-1.27	-4.9	-6.77
	C Asia + East Eur	%	LNG exports	0	0	0	0	-0.46	-3.04	-10.47	-12.43
	Russia	%	LNG exports	0	0	0	0	0.02	-0.95	-5.7	-9.74
	China	%	LNG exports	0	0	0	0	0.2	-8.45	-16.08	-16.59
	India	%	LNG exports	0	0	0	0	0.16	-4.38	-12.25	-14.07
	Middle East	%	LNG exports	0	0	0	0	-0.23	-1.14	-5.83	-8.21
	EU	%	LNG exports	0	0	0	0	0.09	-4.42	-11.87	-12.53
	Mexico	%	LNG exports	0	0	0	0	0.03	-6.1	-14.35	-15.78
	Canada	%	LNG exports	0	0	0	0	-0.3	-1.63	-5.77	-7.1
	USA	%	LNG exports	0	0	0	0	-4.25	27.48	56.79	72.79
		%	Total	0	0	0	0	-4.92	-6.98	-43.14	-49.33
	ROW	%	LNG imports	0	0	0	0	-0.65	4.04	6.26	6.95
	Australia + NZ	%	LNG imports	0	0	0	0	-0.64	3.37	70.21	15.85
	LAC	%	LNG imports	0	0	0	0	-1.48	7.7	10.18	10.32
	Africa	%	LNG imports	0	0	0	0	-1.85	10.71	14.26	13.55
	C Asia + East Eur	%	LNG imports	0	0	0	0	-1.24	6.58	9.33	9.98
	Russia	%	LNG imports	0	0	0	0	-3.2	13.55	18.83	19.62
	China	%	LNG imports	0	0	0	0	-1.03	3.28	5.13	5.77
	India	%	LNG imports	0	0	0	0	-1.01	4.59	7.08	7.81
	Middle East	%	LNG imports	0	0	0	0	-3.4	21.78	25.32	22.96
	EU	%	LNG imports	0	0	0	0	-2.16	10.64	13.33	13.73
	Mexico	%	LNG imports	0	0	0	0	-1.21	7.78	14.18	16.8
	Canada	%	LNG imports	0	0	0	0	-0.55	31.63	41.39	42.83
	USA	%	LNG imports	0	0	0	0	-5.71	56.24	59.76	64.41
		%	Total	0	0	0	0	-24.14	181.9	295.25	250.58
	ROW	%	Pipeline exports	0	0	0	0	-1.28	-0.66	-0.93	-1.65
	Australia + NZ	%	Pipeline exports	0	0	0	0	0.05	-0.47	-1.41	-3.03
	LAC	%	Pipeline exports	0	0	0	0	0.61	-4.2	-8.18	-10.12
	Africa	%	Pipeline exports	0	0	0	0	0.07	-4.41	-6.05	-5.78
	C Asia + East Eur	%	Pipeline exports	0	0	0	0	-1.6	1.1	1.82	-0.02
	Russia	%	Pipeline exports	0	0	0	0	-0.05	-0.9	-3.23	-3.69
	China	%	Pipeline exports	0	0	0	0	2.5	-12.35	-15.31	-13.59
	India	%	Pipeline exports	0	0	0	0	2.25	-12.61	-15.36	-12.63
	Middle East	%	Pipeline exports	0	0	0	0	0.17	-4.45	-7.12	-8.16
	EU	%	Pipeline exports	0	0	0	0	-1.57	-0.46	-2.37	-3.96
	Mexico	%	Pipeline exports	0	0	0	0	-0.36	1.38	-0.44	3.13
	Canada	%	Pipeline exports	0	0	0	0	-0.02	0.56	1.67	3.14
	USA	%	Pipeline exports	0	0	0	0	0	0.05	0	0
		%	Total	0	0	0	0	0.76	-37.41	-56.92	-56.36
	ROW	%	Pipeline imports	0	0	0	0	0.34	-0.89	-2.63	-4.73
	Australia + NZ	%	Pipeline imports	0	0	0	0	-0.47	1.76	5.62	-8.96
	LAC	%	Pipeline imports	0	0	0	0	0.61	-4.2	-8.18	-10.12
	Africa	%	Pipeline imports	0	0	0	0	1.67	-5.81	-6.59	-5.94
	C Asia + East Eur	%	Pipeline imports	0	0	0	0	0.59	-4.29	-8.18	-8.81
	Russia	%	Pipeline imports	0	0	0	0	0.96	-6.5	-9.04	-8.93
	China	%	Pipeline imports	0	0	0	0	-0.5	0.84	-1.58	-2.05
	India	%	Pipeline imports	0	0	0	0	0.69	-1.85	-4.13	-5.15
	Middle East	%	Pipeline imports	0	0	0	0	2.49	-16.6	-18.59	-16.85
	EU	%	Pipeline imports	0	0	0	0	-0.92	-0.19	-0.14	-0.16
	Mexico	%	Pipeline imports	0	0	0	0	0.45	-2.11	-3.12	-4.02
	Canada	%	Pipeline imports	0	0	0	0	0.09	-3.43	-4.69	-5.58
	USA	%	Pipeline imports	0	0	0	0	-0.42	4.5	9.43	15.55
		%	Total	0	0	0	0	5.6	-38.77	-51.84	-65.75

Table D-3. Global primary energy consumption by fuel under S2 and S1 (see Figure 6) and changes in S2 relative to S1

Scenario	Fuel	Units	2015	2020	2025	2030	2035	2040	2045	2050
S1	Biomass	EJ	30.07	32.44	48.96	58.95	69.5	79.75	89.4	95.84
	Biomass CCS	EJ	0	0	5.66	9.4	13.7	20.24	29.79	39.58
	Coal	EJ	165.11	177.1	165.33	171.07	169.73	166.82	161.18	153.04
	Coal CCS	EJ	0	0	1.33	2.61	3.94	5.36	7.04	8.96
	Gas	EJ	126.84	141.53	133.91	142.14	148.85	157.25	171.51	184.76
	Gas CCS	EJ	0	0	3.39	6.49	9.74	12.7	15.18	17.7
	Nuclear	EJ	9.67	10.1	11.77	13.05	14.62	16.48	18.47	20.48
	Oil	EJ	189	192.82	192.8	193.97	193.85	191.61	185.81	179.87
	Oil CCS	EJ	0	0	1.13	2.41	3.86	4.9	5.4	5.97
	Other Renewables	EJ	18.54	24.1	35.17	47.32	59.56	72.42	85.71	99.96
	Total	EJ	520.69	553.99	564.28	600.09	627.79	655.11	683.78	706.2
S2	Biomass	EJ	30.07	32.44	48.96	58.95	69.66	79.06	88.77	95.48
	Biomass CCS	EJ	0	0	5.66	9.4	13.68	20.32	29.96	39.77
	Coal	EJ	165.11	177.1	165.33	171.07	169.88	166.22	160.57	152.42
	Coal CCS	EJ	0	0	1.33	2.61	3.93	5.37	7.04	8.95
	Gas	EJ	126.84	141.53	133.91	142.14	148.46	158.95	173.26	185.96
	Gas CCS	EJ	0	0	3.39	6.49	9.72	12.83	15.38	17.96
	Nuclear	EJ	9.67	10.1	11.77	13.05	14.62	16.47	18.45	20.45
	Oil	EJ	189	192.82	192.8	193.97	193.91	191.29	185.45	179.6
	Oil CCS	EJ	0	0	1.13	2.41	3.86	4.91	5.39	5.96
	Other Renewables	EJ	18.54	24.1	35.17	47.32	59.57	72.34	85.59	99.86
	Total	EJ	509.16	545.65	550.49	588.46	617.63	648.7	681.09	710.93
S2–S1	Biomass	EJ	0	0	0	0	0.16	-0.69	-0.63	-0.36
	Biomass CCS	EJ	0	0	0	0	-0.02	0.08	0.17	0.19
	Coal	EJ	0	0	0	0	0.15	-0.6	-0.61	-0.62
	Coal CCS	EJ	0	0	0	0	-0.01	0.01	0	-0.01
	Gas	EJ	0	0	0	0	-0.39	1.7	1.75	1.2
	Gas CCS	EJ	0	0	0	0	-0.02	0.13	0.2	0.26
	Nuclear	EJ	0	0	0	0	0	-0.01	-0.02	-0.03
	Oil	EJ	0	0	0	0	0.06	-0.32	-0.36	-0.27
	Oil CCS	EJ	0	0	0	0	0	0.01	-0.01	-0.01
	Total	EJ	0	0	0	0	0.01	-0.08	-0.12	-0.1
S2–S1	Biomass	%	0	0	0	0	0.00	-0.01	-0.01	0.00
	Biomass CCS	%	0	0	0	0	0.00	0.00	0.01	0.00
	Coal	%	0	0	0	0	0.00	0.00	0.00	0.00
	Coal CCS	%	0	0	0	0	0.00	0.00	0.00	0.00
	Gas	%	0	0	0	0	0.00	0.01	0.01	0.01
	Gas CCS	%	0	0	0	0	0.00	0.01	0.01	0.01
	Nuclear	%	0	0	0	0	0.00	0.00	0.00	0.00
	Oil	%	0	0	0	0	0.00	0.00	0.00	0.00
	Oil CCS	%	0	0	0	0	0.00	0.00	0.00	0.00
	Total	%	0	0	0	0	0.00	0.00	0.00	0.00

Table D-4. GHG emissions by sector under S2 and S1 (see Figure 6) and changes in S2 relative to S1

Scenario	Sector	Unit	2015	2020	2025	2030	2035	2040	2045	2050
S1	CO_2 buildings	Gt CO_2e	2.84	2.92	2.56	2.63	2.63	2.61	2.59	2.54
	CO_2 electricity	Gt CO_2e	12.64	13.02	12.06	12.81	13.26	13.46	13.39	13.04
	CO_2 industry	Gt CO_2e	11.75	12.98	12.68	12.65	12.14	11.66	11.32	11.04
	CO_2 other energy	Gt CO_2e	0.51	1.23	1.09	1.31	1.43	1.51	1.57	1.6
	CO_2 transport	Gt CO_2e	7.89	8.24	8.06	7.87	7.58	7.31	7.16	7.04
	CH_4 energy	Gt CO_2e	5.43	5.6	4.71	4.85	4.84	4.73	4.78	4.8
	CH_4 AgLanduse	Gt CO_2e	3.36	3.61	3.69	3.98	4.25	4.5	4.75	4.97
	N_2O energy	Gt CO_2e	0.96	0.97	0.93	0.96	0.92	0.86	0.87	0.88
	N_2O AgLanduse	Gt CO_2e	2.17	2.32	2.48	2.65	2.79	2.93	3.1	3.28
	F-gases	Gt CO_2e	1.01	1.33	1.41	1.69	1.76	1.74	1.68	1.66
	CO_2 bioenergy	Gt CO_2e	0	0	-0.34	-0.54	-0.74	-1	-1.33	-1.68
	CO_2 direct air capture	Gt CO_2e	0	0	0	0	-0.01	-0.01	0	0

Scenario	Sector	Unit	2015	2020	2025	2030	2035	2040	2045	2050
	CO_2 LUC	Gt CO_2e	3.04	0.42	0.73	-3.08	-1.75	-1.79	-1.57	-1.42
	Total	**Gt CO_2e**	**51.6**	**52.64**	**50.06**	**47.78**	**49.1**	**48.51**	**48.31**	**47.75**
S2	CO_2 buildings	Gt CO_2e	2.84	2.92	2.56	2.63	2.62	2.63	2.6	2.54
	CO_2 electricity	Gt CO_2e	12.64	13.02	12.06	12.81	13.27	13.45	13.39	13.02
	CO_2 industry	Gt CO_2e	11.75	12.98	12.68	12.65	12.14	11.66	11.32	11.04
	CO_2 other energy	Gt CO_2e	0.51	1.23	1.09	1.31	1.43	1.51	1.57	1.6
	CO_2 transport	Gt CO_2e	7.89	8.24	8.06	7.87	7.58	7.31	7.15	7.03
	CH_4 energy	Gt CO_2e	5.43	5.6	4.71	4.85	4.84	4.73	4.77	4.79
	CH_4 AgLanduse	Gt CO_2e	3.36	3.61	3.69	3.98	4.25	4.49	4.74	4.97
	N_2O energy	Gt CO_2e	0.96	0.97	0.93	0.96	0.92	0.86	0.87	0.88
	N_2O AgLanduse	Gt CO_2e	2.17	2.32	2.48	2.65	2.79	2.93	3.1	3.28
	F-gases	Gt CO_2e	1.01	1.33	1.41	1.69	1.76	1.74	1.68	1.67
	CO_2 bioenergy	Gt CO_2e	0	0	-0.34	-0.54	-0.74	-1	-1.34	-1.69
	CO_2 direct air capture	Gt CO_2e	0	0	0	0	-0.01	-0.01	0	0
	CO_2 LUC	Gt CO_2e	3.04	0.42	0.73	-3.08	-1.72	-2.09	-1.61	-1.39
	Total	**Gt CO_2e**	**51.6**	**52.64**	**50.06**	**47.78**	**49.13**	**48.21**	**48.24**	**47.74**
S2–S1	CO_2 buildings	Gt CO_2e	0	0	0	0	0	0.01	0.01	0.01
	CO_2 electricity	Gt CO_2e	0	0	0	0	0	-0.01	0	-0.02
	CO_2 industry	Gt CO_2e	0	0	0	0	0	0	0	-0.01
	CO_2 other energy	Gt CO_2e	0	0	0	0	0	0	0	0
	CO_2 transport	Gt CO_2e	0	0	0	0	0	0	-0.01	-0.01
	CH_4 energy	Gt CO_2e	0	0	0	0	0	0	-0.01	-0.01
	CH_4 AgLanduse	Gt CO_2e	0	0	0	0	0	0	0	0
	N_2O energy	Gt CO_2e	0	0	0	0	0	0	0	0
	N_2O AgLanduse	Gt CO_2e	0	0	0	0	0	0	0	0
	F-gases	Gt CO_2e	0	0	0	0	0	0	0	0
	CO_2 bioenergy	Gt CO_2e	0	0	0	0	0	-0.01	-0.01	-0.01
	CO_2 direct air capture	Gt CO_2e	0	0	0	0	0	0	0	0
	CO_2 LUC	Gt CO_2e	0	0	0	0	0.03	-0.3	-0.04	0.03
	Total	**Gt CO_2e**	**0**	**0**	**0**	**0**	**0.03**	**-0.31**	**-0.06**	**-0.02**
S2–S1	CO_2 buildings	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	CO_2 electricity	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	CO_2 industry	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	CO_2 other energy	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	CO_2 transport	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	CH_4 energy	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	CH_4 AgLanduse	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	N_2O energy	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	N_2O AgLanduse	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	F-gases	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	CO_2 bioenergy	%	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01
	CO_2 direct air capture	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	CO_2 LUC	%	0.00	0.00	0.00	0.00	-0.02	0.17	0.03	-0.02
	Total	**%**	**0.00**	**0.00**	**0.00**	**0.00**	**-0.02**	**0.18**	**0.03**	**-0.02**

Table D-5. Global primary energy consumption by fuel under S6 and S7 (see Figure 7) and changes in S7 relative to S6

Scenario	Fuel	Units	2015	2020	2025	2030	2035	2040	2045	2050
S6	Biomass	EJ	30.06	32.44	49.56	60.69	69.95	65.82	52.85	35.59
	Biomass CCS	EJ	0	0	7.58	14.81	40.26	66.29	89.57	108.7
	Coal	EJ	165.11	177.09	159.14	161.43	133.25	103.67	70.56	44.43
	Coal CCS	EJ	0	0	1.7	3.45	8.16	16.42	26.45	35.07
	Gas	EJ	126.83	141.49	130.11	131.75	125.14	122.27	113.86	95.07
	Gas CCS	EJ	0	0	3.73	8.48	18.61	29.78	41.85	58.07
	Nuclear	EJ	9.67	10.1	11.98	13.55	16.43	21.14	27.44	34.96
	Oil	EJ	189	192.9	191.77	192.33	184.43	174.89	161.68	144.79
	Oil CCS	EJ	0	0	1.26	2.78	6.09	8.92	11.77	16.07
	Other Renewables	EJ	18.54	24.1	36.56	49.97	67.18	87.31	112.36	142.92
	Total	**EJ**	**539.21**	**578.12**	**593.39**	**639.24**	**669.5**	**696.51**	**708.39**	**715.67**

Scenario	Fuel	Units	2015	2020	2025	2030	2035	2040	2045	2050
S7	Biomass	EJ	30.06	32.44	49.56	60.69	69.95	65.82	52.71	35.54
	Biomass CCS	EJ	0	0	7.58	14.81	40.26	66.29	89.62	108.7
	Coal	EJ	165.11	177.09	159.14	161.43	133.25	103.67	70.47	44.39
	Coal CCS	EJ	0	0	1.7	3.45	8.16	16.42	26.44	35.03
	Gas	EJ	126.83	141.49	130.11	131.76	125.14	122.27	114.19	95.24
	Gas CCS	EJ	0	0	3.73	8.48	18.61	29.78	42.08	58.41
	Nuclear	EJ	9.67	10.1	11.98	13.55	16.43	21.14	27.43	34.94
	Oil	EJ	189	192.9	191.77	192.33	184.43	174.89	161.59	144.71
	Oil CCS	EJ	0	0	1.26	2.78	6.09	8.92	11.75	16.04
	Other Renewables	EJ	18.54	24.1	36.56	49.97	67.18	87.31	112.33	142.87
	Total	**EJ**	**539.21**	**578.12**	**593.39**	**639.25**	**669.5**	**696.51**	**708.61**	**715.87**
S7–S6	Biomass	EJ	0	0	0	0	0	0	-0.13	-0.06
	Biomass CCS	EJ	0	0	0	0	0	0	0.05	0
	Coal	EJ	0	0	0	0	0	0	-0.09	-0.04
	Coal CCS	EJ	0	0	0	0	0	0	-0.01	-0.05
	Gas	EJ	0	0	0	0	0	0	0.34	0.17
	Gas CCS	EJ	0	0	0	0	0	0	0.23	0.34
	Nuclear	EJ	0	0	0	0	0	0	-0.01	-0.03
	Oil	EJ	0	0	0	0	0	0	-0.1	-0.08
	Oil CCS	EJ	0	0	0	0	0	0	-0.01	-0.03
	Other Renewables	EJ	0	0	0	0	0	0	-0.03	-0.05
	Total	**EJ**	**0**	**0**	**0**	**0**	**0**	**0**	**0.24**	**0.17**
	Biomass	%	0	0	0	0	0	0	-0.002	-0.002
	Biomass CCS	%	0	0	0	0	0	0	0.001	0.000
	Coal	%	0	0	0	0	0	0	-0.001	-0.001
	Coal CCS	%	0	0	0	0	0	0	0.000	-0.001
	Gas	%	0	0	0	0	0	0	0.003	0.002
	Gas CCS	%	0	0	0	0	0	0	0.005	0.006
	Nuclear	%	0	0	0	0	0	0	0.000	-0.001
	Oil	%	0	0	0	0	0	0	-0.001	-0.001
	Oil CCS	%	0	0	0	0	0	0	-0.001	-0.002
	Other Renewables	%	0	0	0	0	0	0	0.000	0.000
	Total	**%**	**0**	**0**	**0**	**0**	**0**	**0**	**0.000**	**0.000**

Table D-6. GHG emissions by sector under S7 and S6 (Figure 7) and changes in S7 relative to S6

Scenario	Sector	Unit	2015	2020	2025	2030	2035	2040	2045	2050
S6	CO_2 buildings	Gt CO_2e	2.84	2.92	2.46	2.47	2.09	1.94	1.67	1.12
	CO_2 electricity	Gt CO_2e	12.64	13.02	11.54	11.81	10.02	7.56	4.53	2.16
	CO_2 industry	Gt CO_2e	11.75	12.98	12.46	12.27	10.42	8.83	7.58	6.47
	CO_2 other energy	Gt CO_2e	0.51	1.23	1.06	1.27	1.11	1.08	1.04	0.95
	CO_2 transport	Gt CO_2e	7.89	8.24	7.99	7.74	7.11	6.51	5.9	5
	CH_4 energy	Gt CO_2e	5.43	5.6	4.55	4.65	4.32	4	3.56	3.25
	CH_4 AgLanduse	Gt CO_2e	3.36	3.61	3.68	3.95	4.14	4.33	4.51	4.69
	N_2O energy	Gt CO_2e	0.96	0.97	0.9	0.92	0.82	0.74	0.66	0.59
	N_2O AgLanduse	Gt CO_2e	2.17	2.32	2.43	2.59	2.74	2.86	2.96	3.03
	F-gases	Gt CO_2e	1.01	1.33	1.37	1.62	1.58	1.5	1.23	1.07
	CO_2 bioenergy	Gt CO_2e	0	0	-0.46	-0.9	-2.46	-4.02	-5.35	-6.81
	CO_2 direct air capture	Gt CO_2e	0	0	0	-0.04	-0.28	-0.42	-0.44	-0.47
	CO_2 LUC	Gt CO_2e	3.04	0.56	0.82	-3.26	-2.38	-2.84	-3.12	-3.92
	Total	**Gt CO_2e**	**51.6**	**52.78**	**48.8**	**45.09**	**39.23**	**32.07**	**24.73**	**17.13**
S7	CO_2 buildings	Gt CO_2e	2.84	2.92	2.46	2.47	2.09	1.94	1.68	1.12
	CO_2 electricity	Gt CO_2e	12.64	13.02	11.54	11.81	10.02	7.56	4.53	2.16
	CO_2 industry	Gt CO_2e	11.75	12.98	12.46	12.27	10.42	8.83	7.58	6.47
	CO_2 other energy	Gt CO_2e	0.51	1.23	1.06	1.27	1.11	1.08	1.04	0.95
	CO_2 transport	Gt CO_2e	7.89	8.24	7.99	7.74	7.11	6.51	5.9	5
	CH_4 energy	Gt CO_2e	5.43	5.6	4.55	4.65	4.32	4	3.56	3.24
	CH_4 AgLanduse	Gt CO_2e	3.36	3.61	3.68	3.95	4.14	4.33	4.51	4.69
	N_2O energy	Gt CO_2e	0.96	0.97	0.9	0.92	0.82	0.74	0.66	0.59
	N_2O AgLanduse	Gt CO_2e	2.17	2.32	2.43	2.59	2.74	2.86	2.96	3.03
	F-gases	Gt CO_2e	1.01	1.33	1.37	1.62	1.58	1.5	1.23	1.07

Scenario	Sector	Unit	2015	2020	2025	2030	2035	2040	2045	2050
	CO_2 bioenergy	Gt CO_2e	0	0	-0.46	-0.9	-2.46	-4.02	-5.36	-6.81
	CO_2 direct air capture	Gt CO_2e	0	0	0	-0.04	-0.28	-0.42	-0.44	-0.47
	CO_2 LUC	Gt CO_2e	3.04	0.56	0.82	-3.26	-2.38	-2.84	-3.13	-3.92
	Total	Gt CO_2e	51.6	52.78	48.8	45.09	39.23	32.07	24.72	17.12
Delta S7–S6	CO_2 buildings	Gt CO_2e	0	0	0	0	0	0	0	0
	CO_2 electricity	Gt CO_2e	0	0	0	0	0	0	0	0
	CO_2 industry	Gt CO_2e	0	0	0	0	0	0	0	0
	CO_2 other energy	Gt CO_2e	0	0	0	0	0	0	0	0
	CO_2 transport	Gt CO_2e	0	0	0	0	0	0	0	0
	CH_4 energy	Gt CO_2e	0	0	0	0	0	0	0	-0.01
	CH_4 AgLanduse	Gt CO_2e	0	0	0	0	0	0	0	0
	N_2O energy	Gt CO_2e	0	0	0	0	0	0	0	0
	N_2O AgLanduse	Gt CO_2e	0	0	0	0	0	0	0	0
	F-gases	Gt CO_2e	0	0	0	0	0	0	0	0
	CO_2 bioenergy	Gt CO_2e	0	0	0	0	0	0	0	0
	CO_2 direct air capture	Gt CO_2e	0	0	0	0	0	0	0	0
	CO_2 LUC	Gt CO_2e	0	0	0	0	0	0	-0.01	0
	Total	Gt CO_2e	0	0	0	0	0	0	-0.01	-0.01
	CO_2 buildings	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	CO_2 electricity	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	CO_2 industry	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	CO_2 other energy	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	CO_2 transport	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	CH_4 energy	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	CH_4 AgLanduse	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	N_2O energy	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	N_2O AgLanduse	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	F-gases	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	CO_2 bioenergy	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	CO_2 direct air capture	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	CO_2 LUC	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Total	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table D-7. Changes in global primary energy consumption under S6 and S7 relative to S1 and S2 respectively (see Figure 8)

Scenario	Fuel	Units	2015	2020	2025	2030	2035	2040	2045	2050
S6–S1	Biomass	EJ	0	0	0.6	1.73	0.46	-13.94	-36.55	-60.25
	Biomass CCS	EJ	0	0	1.92	5.41	26.55	46.05	59.78	69.12
	Coal	EJ	0	-0.01	-6.19	-9.64	-36.48	-63.15	-90.63	-108.6
	Coal CCS	EJ	0	0	0.38	0.84	4.22	11.06	19.41	26.11
	Gas	EJ	0	-0.05	-3.8	-10.39	-23.71	-34.98	-57.65	-89.7
	Gas CCS	EJ	0	0	0.34	1.99	8.87	17.07	26.67	40.37
	Nuclear	EJ	0	0	0.21	0.49	1.81	4.66	8.97	14.48
	Oil	EJ	0	0.07	-1.02	-1.63	-9.42	-16.72	-24.13	-35.08
	Oil CCS	EJ	0	0	0.13	0.38	2.23	4.01	6.37	10.1
	Other Renewables	EJ	0	0	1.39	2.64	7.62	14.89	26.65	42.95
	Total	**EJ**	**0**	**0.01**	**-6.04**	**-8.18**	**-17.85**	**-31.05**	**-61.11**	**-90.51**
S7–S2	Biomass	EJ	0	0	0.6	1.73	0.3	-13.24	-36.06	-59.95
	Biomass CCS	EJ	0	0	1.92	5.41	26.57	45.97	59.66	68.94
	Coal	EJ	0	-0.01	-6.19	-9.64	-36.63	-62.55	-90.1	-108
	Coal CCS	EJ	0	0	0.38	0.84	4.22	11.05	19.4	26.08
	Gas	EJ	0	-0.05	-3.8	-10.39	-23.32	-36.68	-59.07	-90.72
	Gas CCS	EJ	0	0	0.34	1.99	8.9	16.94	26.7	40.46
	Nuclear	EJ	0	0	0.21	0.49	1.81	4.67	8.98	14.49
	Oil	EJ	0	0.07	-1.02	-1.63	-9.48	-16.4	-23.86	-34.89
	Oil CCS	EJ	0	0	0.13	0.38	2.23	4	6.36	10.09
	Other Renewables	EJ	0	0	1.39	2.64	7.61	14.97	26.74	43.01
	Total	**EJ**	**0**	**0.01**	**-6.04**	**-8.18**	**-17.79**	**-31.27**	**-61.25**	**-90.52**

Scenario	Fuel	Units	2015	2020	2025	2030	2035	2040	2045	2050
S6–S1	Biomass	%	0.00	0.00	1.23	2.93	0.66	-17.48	-40.88	-62.87
	Biomass CCS	%	0.00	0.00	33.92	57.55	193.80	227.52	200.67	174.63
	Coal	%	0.00	-0.01	-3.74	-5.64	-21.49	-37.86	-56.23	-70.97
	Coal CCS	%	0.00	0.00	28.57	32.18	107.11	206.34	275.71	291.41
	Gas	%	0.00	-0.04	-2.84	-7.31	-15.93	-22.24	-33.61	-48.55
	Gas CCS	%	0.00	0.00	10.03	30.66	91.07	134.41	175.69	228.08
	Nuclear	%	0.00	0.00	1.78	3.75	12.38	28.28	48.57	70.70
	Oil	%	0.00	0.04	-0.53	-0.84	-4.86	-8.73	-12.99	-19.50
	Oil CCS	%	0.00	0.00	11.50	15.77	57.77	81.84	117.96	169.18
	Other Renewables	%	0.00	0.00	3.95	5.58	12.79	20.56	31.09	42.97
	Total	%	**0.00**	**0.00**	**-1.07**	**-1.36**	**-2.84**	**-4.74**	**-8.94**	**-12.82**
S7–S2	Biomass	%	0.00	0.00	1.23	2.93	0.43	-16.75	-40.62	-62.79
	Biomass CCS	%	0.00	0.00	33.92	57.55	194.23	226.23	199.13	173.35
	Coal	%	0.00	-0.01	-3.74	-5.64	-21.56	-37.63	-56.11	-70.88
	Coal CCS	%	0.00	0.00	28.57	32.18	107.38	205.77	275.57	291.40
	Gas	%	0.00	-0.04	-2.84	-7.31	-15.71	-23.08	-34.09	-48.78
	Gas CCS	%	0.00	0.00	10.03	30.66	91.56	132.03	173.60	225.28
	Nuclear	%	0.00	0.00	1.78	3.75	12.38	28.35	48.67	70.86
	Oil	%	0.00	0.04	-0.53	-0.84	-4.89	-8.57	-12.87	-19.43
	Oil CCS	%	0.00	0.00	11.50	15.77	57.77	81.47	118.00	169.30
	Other Renewables	%	0.00	0.00	3.95	5.58	12.77	20.69	31.24	43.07
	Total	%	**0.00**	**0.00**	**-1.10**	**-1.39**	**-2.88**	**-4.82**	**-8.99**	**-12.73**

Table D-8. Changes in global GHG emissions by sector under S6 and S7 relative to S1 and S2, respectively (see Figure 8)

Scenario	Sector	Units	2015	2020	2025	2030	2035	2040	2045	2050
S6–S1	CO_2 buildings	Gt CO_2e	0	0	-0.1	-0.16	-0.54	-0.67	-0.91	-1.42
	CO_2 electricity	Gt CO_2e	0	0	-0.52	-1	-3.25	-5.9	-8.86	-10.88
	CO_2 industry	Gt CO_2e	0	0	-0.22	-0.38	-1.71	-2.83	-3.75	-4.57
	CO_2 other energy	Gt CO_2e	0	0	-0.03	-0.05	-0.32	-0.43	-0.53	-0.65
	CO_2 transport	Gt CO_2e	0	0	-0.08	-0.13	-0.47	-0.8	-1.26	-2.03
	CH_4 energy	Gt CO_2e	0	0	-0.16	-0.2	-0.52	-0.73	-1.21	-1.55
	CH_4 AgLanduse	Gt CO_2e	0	0	-0.01	-0.02	-0.11	-0.17	-0.24	-0.28
	N_2O energy	Gt CO_2e	0	0	-0.03	-0.03	-0.1	-0.12	-0.21	-0.29
	N_2O AgLanduse	Gt CO_2e	0	0	-0.05	-0.06	-0.05	-0.06	-0.14	-0.25
	F-gases	Gt CO_2e	0	0	-0.04	-0.07	-0.18	-0.23	-0.45	-0.59
	CO_2 bioenergy	Gt CO_2e	0	0	-0.12	-0.36	-1.71	-3.02	-4.02	-5.12
	CO_2 direct air capture	Gt CO_2e	0	0	0	-0.03	-0.27	-0.41	-0.44	-0.47
	CO_2 LUC	Gt CO_2e	0	0.14	0.09	-0.17	-0.62	-1.05	-1.55	-2.5
	Total	Gt CO_2e	0	0.14	-1.27	-2.66	-9.85	-16.4	-23.6	-30.6
S7–S2	CO_2 buildings	Gt CO_2e	0	0	-0.1	-0.16	-0.53	-0.68	-0.92	-1.43
	CO_2 electricity	Gt CO_2e	0	0	-0.52	-1	-3.25	-5.89	-8.85	-10.86
	CO_2 industry	Gt CO_2e	0	0	-0.22	-0.38	-1.71	-2.83	-3.74	-4.56
	CO_2 other energy	Gt CO_2e	0	0	-0.03	-0.05	-0.32	-0.43	-0.53	-0.65
	CO_2 transport	Gt CO_2e	0	0	-0.08	-0.13	-0.47	-0.8	-1.25	-2.03
	CH_4 energy	Gt CO_2e	0	0	-0.16	-0.2	-0.52	-0.72	-1.21	-1.54
	CH_4 AgLanduse	Gt CO_2e	0	0	-0.01	-0.02	-0.11	-0.17	-0.24	-0.28
	N_2O energy	Gt CO_2e	0	0	-0.03	-0.03	-0.1	-0.12	-0.21	-0.29
	N_2O AgLanduse	Gt CO_2e	0	0	-0.05	-0.06	-0.05	-0.06	-0.14	-0.25
	F-gases	Gt CO_2e	0	0	-0.04	-0.07	-0.18	-0.24	-0.45	-0.6
	CO_2 bioenergy	Gt CO_2e	0	0	-0.12	-0.36	-1.72	-3.01	-4.01	-5.11
	CO_2 direct air capture	Gt CO_2e	0	0	0	-0.03	-0.27	-0.41	-0.44	-0.47
	CO_2 LUC	Gt CO_2e	0	0.14	0.09	-0.17	-0.66	-0.75	-1.52	-2.53
	Total	Gt CO_2e	0	0.14	-1.27	-2.66	-9.89	-16.1	-23.5	-30.6
S6–S1	CO_2 buildings	%	0	0	-3.91	-6.08	-20.5	-25.7	-35.1	-55.91
	CO_2 electricity	%	0	0	-4.31	-7.81	-24.5	-43.8	-66.2	-83.44
	CO_2 industry	%	0	0	-1.74	-3	-14.1	-24.3	-33.1	-41.39
	CO_2 other energy	%	0	0	-2.75	-3.82	-22.4	-28.5	-33.8	-40.63
	CO_2 transport	%	0	0	-0.99	-1.65	-6.2	-10.9	-17.6	-28.84
	CH_4 energy	%	0	0	-3.4	-4.12	-10.7	-15.4	-25.3	-32.29

Scenario	Sector	Units	2015	2020	2025	2030	2035	2040	2045	2050
	CH_4 AgLanduse	%	0	0	-0.27	-0.5	-2.59	-3.78	-5.05	-5.634
	N_2O energy	%	0	0	-3.23	-3.13	-10.9	-14	-24.1	-32.95
	N_2O AgLanduse	%	0	0	-2.02	-2.26	-1.79	-2.05	-4.52	-7.622
	F-gases	%	0	0	-2.84	-4.14	-10.2	-13.2	-26.8	-35.54
	CO_2 bioenergy	%	0	0	35.3	66.7	231	302	302	304.8
	CO_2 direct air capture	%	0	0	0	0	2700	4100	0	0
	CO_2 LUC	%	0	33.3	12.3	5.52	35.4	58.7	98.7	176.1
	Total	%	0	0.27	-2.54	-5.57	-20.1	-33.8	-48.8	-64.08
S7–S2	CO_2 buildings	%	0	0	-3.91	-6.08	-20.2	-25.9	-35.4	-56.3
	CO_2 electricity	%	0	0	-4.31	-7.81	-24.5	-43.8	-66.1	-83.41
	CO_2 industry	%	0	0	-1.74	-3	-14.1	-24.3	-33	-41.3
	CO_2 other energy	%	0	0	-2.75	-3.82	-22.4	-28.5	-33.8	-40.63
	CO_2 transport	%	0	0	-0.99	-1.65	-6.2	-10.9	-17.5	-28.88
	CH_4 energy	%	0	0	-3.4	-4.12	-10.7	-15.2	-25.4	-32.15
	CH_4 AgLanduse	%	0	0	-0.27	-0.5	-2.59	-3.79	-5.06	-5.634
	N_2O energy	%	0	0	-3.23	-3.13	-10.9	-14	-24.1	-32.95
	N_2O AgLanduse	%	0	0	-2.02	-2.26	-1.79	-2.05	-4.52	-7.622
	F-gases	%	0	0	-2.84	-4.14	-10.2	-13.8	-26.8	-35.93
	CO_2 bioenergy	%	0	0	35.3	66.7	232	301	299	302.4
	CO_2 direct air capture	%	0	0	0	0	2700	4100	0	0
	CO_2 LUC	%	0	33.3	12.3	5.52	38.4	35.9	94.4	182
	Total	%	0	0.27	-2.54	-5.57	-20.1	-33.4	-48.7	-64.1

Table D-9. CDR deployment by type in S6 and S7 and changes in S7 relative to S6 (see Figure 9)

Scenario	Sector	Units	2015	2020	2025	2030	2035	2040	2045	2050
S6	BECCS	Gt CO_2e	0	0	0.46	0.9	2.46	4.02	5.35	6.81
	DAC	Gt CO_2e	0	0	0	0.04	0.28	0.42	0.44	0.47
	Afforestation	Gt CO_2e	1.38	1.54	1.5	3.99	3.38	3.37	3.43	4.06
	Total	Gt CO_2e	1.38	1.54	1.96	4.93	6.12	7.81	9.22	11.3
S7	BECCS	Gt CO_2e	0	0	0.46	0.9	2.46	4.02	5.36	6.81
	DAC	Gt CO_2e	0	0	0	0.04	0.28	0.42	0.44	0.47
	Afforestation	Gt CO_2e	1.38	1.54	1.5	3.99	3.38	3.37	3.44	4.06
	Total	Gt CO_2e	1.38	1.54	1.96	4.93	6.12	7.81	9.24	11.3
S7–S6	BECCS	Gt CO_2e	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DAC	Gt CO_2e	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Afforestation	Gt CO_2e	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Total	Gt CO_2e	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	BECCS	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DAC	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Afforestation	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Total	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table D-10. Natural gas consumption, production, consumption, and trade by region under S6 and S7 (see Figure 10) and changes in S7 relative to S6 (see Figure 12)

Scenario	Region	Unit	NG Volumes	2020	2025	2030	2035	2040	2045	2050
S6	ROW	Bcf/d	Consumption	42.29	39.95	42.56	42.59	44	46.19	45.43
	Australia + NZ	Bcf/d	Consumption	0.79	0.33	0.49	0.34	0.44	0.63	0.91
	LAC	Bcf/d	Consumption	17.55	16.52	19.24	20.64	22.58	23.55	24.91
	Africa	Bcf/d	Consumption	14.45	14.23	16.98	20.22	25.07	31.92	38.76
	C Asia + East Eur	Bcf/d	Consumption	28.94	30.46	32.45	32.35	32.44	30.5	28.2
	Russia	Bcf/d	Consumption	45.82	36.03	39.59	39.92	39.43	36.08	33.1
	China	Bcf/d	Consumption	27.43	41.73	46.57	52.25	59.32	66.21	64.93
	India	Bcf/d	Consumption	7.96	11.56	16.4	21.55	27.64	34.62	40.31
	Middle East	Bcf/d	Consumption	46.41	45.15	47.15	46.26	46.8	47.07	45.5
	EU	Bcf/d	Consumption	48.18	35	28.79	24.88	26.86	29.64	28.38
	Mexico	Bcf/d	Consumption	8.28	8.19	9.5	9.81	9.99	10.28	10.83
	Canada	Bcf/d	Consumption	11.44	8.25	8.26	6.72	5.99	5.53	4.98
	USA	Bcf/d	Consumption	80.45	75.28	76.47	76.36	79.45	77.9	75.67
		Bcf/d	Total	380	362.69	384.44	393.88	420.01	440.11	441.92

Scenario	Region	Unit	NG Volumes	2020	2025	2030	2035	2040	2045	2050
S7	ROW	Bcf/d	Consumption	42.29	39.95	42.56	42.59	44	46.65	45.95
	Australia + NZ	Bcf/d	Consumption	0.79	0.33	0.49	0.34	0.44	0.64	0.92
	LAC	Bcf/d	Consumption	17.55	16.52	19.24	20.64	22.58	23.78	25.2
	Africa	Bcf/d	Consumption	14.45	14.23	16.98	20.22	25.07	32.01	38.94
	C Asia + East Eur	Bcf/d	Consumption	28.94	30.46	32.45	32.35	32.44	30.57	28.27
	Russia	Bcf/d	Consumption	45.82	36.03	39.59	39.92	39.43	36.09	33.12
	China	Bcf/d	Consumption	27.43	41.73	46.57	52.25	59.32	66.39	65.02
	India	Bcf/d	Consumption	7.96	11.56	16.4	21.55	27.64	34.86	40.59
	Middle East	Bcf/d	Consumption	46.41	45.15	47.15	46.26	46.8	47.06	45.5
	EU	Bcf/d	Consumption	48.18	35	28.79	24.88	26.86	30.04	28.53
	Mexico	Bcf/d	Consumption	8.28	8.19	9.5	9.81	9.99	10.28	10.84
	Canada	Bcf/d	Consumption	11.44	8.25	8.26	6.72	5.99	5.54	5
	USA	Bcf/d	Consumption	80.45	75.28	76.47	76.36	79.45	77.73	75.42
		Bcf/d	**Total**	**380**	**362.69**	**384.44**	**393.88**	**420.01**	**441.64**	**443.29**
S6	ROW	Bcf/d	Production	41.02	37.63	40.92	41.75	42.28	43.38	43.46
	Australia + NZ	Bcf/d	Production	12.71	12.21	12.09	10.84	9.16	7.08	5.31
	LAC	Bcf/d	Production	15.44	13.65	15.64	16.05	16.86	17.9	19.08
	Africa	Bcf/d	Production	23.83	24.62	27.17	29.58	33.29	38.2	42.33
	C Asia + East Eur	Bcf/d	Production	17.31	17.51	18.71	18.64	19.21	19.55	19.79
	Russia	Bcf/d	Production	70.26	59.65	62.68	61.92	64.03	65.28	61.94
	China	Bcf/d	Production	16.74	19.7	22.17	23.72	25.2	26.33	24.8
	India	Bcf/d	Production	4.02	4.75	7.01	9.46	12.66	17	20.74
	Middle East	Bcf/d	Production	59.39	57.77	59.86	59.95	61.7	63.69	63.1
	EU	Bcf/d	Production	13.69	9.87	8.52	7.91	9.03	13.03	14.42
	Mexico	Bcf/d	Production	3.21	2.39	3.14	3.2	3.3	3.52	3.96
	Canada	Bcf/d	Production	15.11	14.11	14.29	13.94	14.97	15.66	15.04
	USA	Bcf/d	Production	87.26	88.83	92.25	96.9	108.31	109.49	107.95
		Bcf/d	**Total**	**379.99**	**362.69**	**384.45**	**393.86**	**420**	**440.11**	**441.92**
S7	ROW	Bcf/d	Production	41.02	37.63	40.92	41.75	42.28	43.14	43
	Australia + NZ	Bcf/d	Production	12.71	12.21	12.09	10.84	9.16	7.05	5.21
	LAC	Bcf/d	Production	15.44	13.65	15.64	16.05	16.86	17.71	18.72
	Africa	Bcf/d	Production	23.83	24.62	27.17	29.58	33.29	37.81	41.66
	C Asia + East Eur	Bcf/d	Production	17.31	17.51	18.71	18.64	19.21	19.4	19.44
	Russia	Bcf/d	Production	70.26	59.65	62.68	61.92	64.03	64.96	61.24
	China	Bcf/d	Production	16.74	19.7	22.17	23.72	25.2	26.3	24.74
	India	Bcf/d	Production	4.02	4.75	7.01	9.46	12.66	16.8	20.38
	Middle East	Bcf/d	Production	59.39	57.77	59.86	59.95	61.7	63.27	62.29
	EU	Bcf/d	Production	13.69	9.87	8.52	7.91	9.03	12.87	13.99
	Mexico	Bcf/d	Production	3.21	2.39	3.14	3.2	3.3	3.5	3.93
	Canada	Bcf/d	Production	15.11	14.11	14.29	13.94	14.97	15.55	14.81
	USA	Bcf/d	Production	87.26	88.83	92.25	96.9	108.31	113.29	113.87
		Bcf/d	**Total**	**379.99**	**362.69**	**384.45**	**393.86**	**420**	**441.65**	**443.28**
S6	ROW	Bcf/d	LNG exports	10.56	11.06	13.52	15.16	15.5	16.15	16.3
	Australia + NZ	Bcf/d	LNG exports	11.93	11.88	11.61	10.51	8.72	6.46	4.55
	LAC	Bcf/d	LNG exports	1.83	2.17	2.46	3.06	4.03	5.2	5.93
	Africa	Bcf/d	LNG exports	9.09	10.61	11.28	11.59	12.1	12.3	11.73
	C Asia + East Eur	Bcf/d	LNG exports	0.06	0.16	0.33	0.81	1.94	3.6	5.03
	Russia	Bcf/d	LNG exports	3.05	3.81	3.89	3.56	3.09	2.72	2.5
	China	Bcf/d	LNG exports	0	0	0	0.02	0.04	0.07	0.09
	India	Bcf/d	LNG exports	0.01	0.01	0.04	0.07	0.15	0.27	0.37
	Middle East	Bcf/d	LNG exports	13.4	13.05	13.27	14.4	16.11	18.04	19.03
	EU	Bcf/d	LNG exports	0.37	0.47	0.61	0.75	1.29	2.21	3.07
	Mexico	Bcf/d	LNG exports	0	0	0.01	0.02	0.07	0.14	0.22
	Canada	Bcf/d	LNG exports	0.01	2.01	2.42	4.08	6.85	9.01	9.49
	USA	Bcf/d	LNG exports	7.03	13.33	14.75	18.68	25.79	27.33	27.33
		Bcf/d	**Total**	**57.34**	**68.56**	**74.19**	**82.71**	**95.68**	**103.5**	**105.64**
S7	ROW	Bcf/d	LNG exports	10.56	11.06	13.52	15.16	15.5	15.97	15.92
	Australia + NZ	Bcf/d	LNG exports	11.93	11.88	11.61	10.51	8.72	6.42	4.46
	LAC	Bcf/d	LNG exports	1.83	2.17	2.46	3.06	4.03	5.1	5.73
	Africa	Bcf/d	LNG exports	9.09	10.61	11.28	11.59	12.1	12.14	11.4
	C Asia + East Eur	Bcf/d	LNG exports	0.06	0.16	0.33	0.81	1.94	3.49	4.73
	Russia	Bcf/d	LNG exports	3.05	3.81	3.89	3.56	3.09	2.68	2.4

Scenario	Region	Unit	NG Volumes	2020	2025	2030	2035	2040	2045	2050
	China	Bcf/d	LNG exports	0	0	0	0.02	0.04	0.07	0.09
	India	Bcf/d	LNG exports	0.01	0.01	0.04	0.07	0.15	0.26	0.34
	Middle East	Bcf/d	LNG exports	13.4	13.05	13.27	14.4	16.11	17.77	18.37
	EU	Bcf/d	LNG exports	0.37	0.47	0.61	0.75	1.29	2.14	2.87
	Mexico	Bcf/d	LNG exports	0	0	0.01	0.02	0.07	0.14	0.2
	Canada	Bcf/d	LNG exports	0.01	2.01	2.42	4.08	6.85	8.89	9.25
	USA	Bcf/d	LNG exports	7.03	13.33	14.75	18.68	25.79	31.37	33.59
		Bcf/d	**Total**	**57.34**	**68.56**	**74.19**	**82.71**	**95.68**	**106.44**	**109.35**
S6	ROW	Bcf/d	LNG imports	20.88	19.92	20.38	20.28	20.94	20.86	18.94
	Australia + NZ	Bcf/d	LNG imports	0.01	0	0	0	0	0.01	0.15
	LAC	Bcf/d	LNG imports	3.94	5.05	6.06	7.64	9.75	10.85	11.76
	Africa	Bcf/d	LNG imports	0.97	1.17	1.83	2.84	4.4	6.26	8.21
	C Asia + East Eur	Bcf/d	LNG imports	6.4	8.07	8.92	9.85	10.96	10.75	10.25
	Russia	Bcf/d	LNG imports	0.82	0.68	0.81	1.82	3	3.33	3.37
	China	Bcf/d	LNG imports	6.98	16.04	17.19	18.43	19.58	19.91	19.61
	India	Bcf/d	LNG imports	3.94	6.83	9.43	12.16	15.13	17.89	19.95
	Middle East	Bcf/d	LNG imports	0.43	0.43	0.54	0.7	1.18	1.36	1.38
	EU	Bcf/d	LNG imports	11.32	8.65	7.28	7.37	9.19	10.77	10.46
	Mexico	Bcf/d	LNG imports	1.15	1.35	1.4	1.36	1.31	1.27	1.31
	Canada	Bcf/d	LNG imports	0.21	0.15	0.15	0.12	0.13	0.17	0.19
	USA	Bcf/d	LNG imports	0.26	0.24	0.18	0.14	0.12	0.08	0.08
		Bcf/d	**Total**	**57.31**	**68.58**	**74.17**	**82.71**	**95.69**	**103.51**	**105.66**
S7	ROW	Bcf/d	LNG imports	20.88	19.92	20.38	20.28	20.94	21.37	19.55
	Australia + NZ	Bcf/d	LNG imports	0.01	0	0	0	0	0.01	0.17
	LAC	Bcf/d	LNG imports	3.94	5.05	6.06	7.64	9.75	11.18	12.21
	Africa	Bcf/d	LNG imports	0.97	1.17	1.83	2.84	4.4	6.59	8.74
	C Asia + East Eur	Bcf/d	LNG imports	6.4	8.07	8.92	9.85	10.96	10.92	10.44
	Russia	Bcf/d	LNG imports	0.82	0.68	0.81	1.82	3	3.45	3.51
	China	Bcf/d	LNG imports	6.98	16.04	17.19	18.43	19.58	20.23	19.95
	India	Bcf/d	LNG imports	3.94	6.83	9.43	12.16	15.13	18.31	20.55
	Middle East	Bcf/d	LNG imports	0.43	0.43	0.54	0.7	1.18	1.52	1.54
	EU	Bcf/d	LNG imports	11.32	8.65	7.28	7.37	9.19	11.26	11.01
	Mexico	Bcf/d	LNG imports	1.15	1.35	1.4	1.36	1.31	1.31	1.36
	Canada	Bcf/d	LNG imports	0.21	0.15	0.15	0.12	0.13	0.19	0.22
	USA	Bcf/d	LNG imports	0.26	0.24	0.18	0.14	0.12	0.1	0.09
		Bcf/d	**Total**	**57.31**	**68.58**	**74.17**	**82.71**	**95.69**	**106.44**	**109.34**
S6	ROW	Bcf/d	Pipeline exports	10.05	7.37	6.09	5.05	4.42	2.64	1.55
	Australia + NZ	Bcf/d	Pipeline exports	0	0	0	0	0	0	0
	LAC	Bcf/d	Pipeline exports	2.11	1.81	1.81	1.53	1.2	0.97	0.92
	Africa	Bcf/d	Pipeline exports	1.42	1.11	1.11	1.44	2.31	3.73	5.77
	C Asia + East Eur	Bcf/d	Pipeline exports	0.07	0.05	0.04	0.03	0.03	0.01	0.01
	Russia	Bcf/d	Pipeline exports	23.46	21.46	21.08	21.63	26.42	32.12	32.15
	China	Bcf/d	Pipeline exports	0	0	0	0	0	0	0
	India	Bcf/d	Pipeline exports	0	0	0	0	0	0	0
	Middle East	Bcf/d	Pipeline exports	0.03	0.02	0.02	0.03	0.05	0.08	0.12
	EU	Bcf/d	Pipeline exports	2.21	1.58	1.26	1.03	0.89	0.46	0.23
	Mexico	Bcf/d	Pipeline exports	0.01	0	0.01	0.03	0.08	0.17	0.29
	Canada	Bcf/d	Pipeline exports	6.23	5.73	5.48	4.68	3.66	2.79	2.23
	USA	Bcf/d	Pipeline exports	8.53	8.53	8.53	8.53	8.53	8.53	8.53
		Bcf/d	**Total**	**54.12**	**47.66**	**45.43**	**43.98**	**47.59**	**51.5**	**51.8**
S7	ROW	Bcf/d	Pipeline exports	10.05	7.37	6.09	5.05	4.42	2.62	1.53
	Australia + NZ	Bcf/d	Pipeline exports	0	0	0	0	0	0	0
	LAC	Bcf/d	Pipeline exports	2.11	1.81	1.81	1.53	1.2	0.95	0.88
	Africa	Bcf/d	Pipeline exports	1.42	1.11	1.11	1.44	2.31	3.62	5.58
	C Asia + East Eur	Bcf/d	Pipeline exports	0.07	0.05	0.04	0.03	0.03	0.01	0.01
	Russia	Bcf/d	Pipeline exports	23.46	21.46	21.08	21.63	26.42	31.88	31.62
	China	Bcf/d	Pipeline exports	0	0	0	0	0	0	0
	India	Bcf/d	Pipeline exports	0	0	0	0	0	0	0
	Middle East	Bcf/d	Pipeline exports	0.03	0.02	0.02	0.03	0.05	0.07	0.12
	EU	Bcf/d	Pipeline exports	2.21	1.58	1.26	1.03	0.89	0.46	0.23
	Mexico	Bcf/d	Pipeline exports	0.01	0	0.01	0.03	0.08	0.17	0.28
	Canada	Bcf/d	Pipeline exports	6.23	5.73	5.48	4.68	3.66	2.79	2.23

Scenario	Region	Unit	NG Volumes	2020	2025	2030	2035	2040	2045	2050
	USA	Bcf/d	Pipeline exports	8.53	8.53	8.53	8.53	8.53	8.53	8.53
		Bcf/d	**Total**	**54.12**	**47.66**	**45.43**	**43.98**	**47.59**	**51.1**	**51.01**
S6	ROW	Bcf/d	Pipeline imports	1	0.82	0.86	0.77	0.7	0.74	0.88
	Australia + NZ	Bcf/d	Pipeline imports	0	0	0	0	0	0	0
	LAC	Bcf/d	Pipeline imports	2.11	1.81	1.81	1.53	1.2	0.97	0.92
	Africa	Bcf/d	Pipeline imports	0.15	0.16	0.37	0.84	1.8	3.48	5.73
	C Asia + East Eur	Bcf/d	Pipeline imports	5.37	5.09	5.19	4.7	4.24	3.82	3.2
	Russia	Bcf/d	Pipeline imports	1.25	0.97	1.08	1.36	1.9	2.3	2.44
	China	Bcf/d	Pipeline imports	3.7	5.99	7.21	10.12	14.58	20.04	20.62
	India	Bcf/d	Pipeline imports	0	0	0	0	0	0	0
	Middle East	Bcf/d	Pipeline imports	0.02	0.03	0.03	0.04	0.08	0.14	0.18
	EU	Bcf/d	Pipeline imports	25.74	18.52	14.86	11.38	10.82	8.52	6.8
	Mexico	Bcf/d	Pipeline imports	3.93	4.45	4.98	5.29	5.53	5.81	6.08
	Canada	Bcf/d	Pipeline imports	2.35	1.73	1.72	1.42	1.4	1.5	1.47
	USA	Bcf/d	Pipeline imports	8.48	8.07	7.32	6.52	5.34	4.19	3.51
		Bcf/d	**Total**	**54.1**	**47.64**	**45.43**	**43.97**	**47.59**	**51.51**	**51.83**
S7	ROW	Bcf/d	Pipeline imports	1	0.82	0.86	0.77	0.7	0.73	0.85
	Australia + NZ	Bcf/d	Pipeline imports	0	0	0	0	0	0	0
	LAC	Bcf/d	Pipeline imports	2.11	1.81	1.81	1.53	1.2	0.95	0.88
	Africa	Bcf/d	Pipeline imports	0.15	0.16	0.37	0.84	1.8	3.38	5.53
	C Asia + East Eur	Bcf/d	Pipeline imports	5.37	5.09	5.19	4.7	4.24	3.76	3.13
	Russia	Bcf/d	Pipeline imports	1.25	0.97	1.08	1.36	1.9	2.25	2.38
	China	Bcf/d	Pipeline imports	3.7	5.99	7.21	10.12	14.58	19.92	20.41
	India	Bcf/d	Pipeline imports	0	0	0	0	0	0	0
	Middle East	Bcf/d	Pipeline imports	0.02	0.03	0.03	0.04	0.08	0.13	0.16
	EU	Bcf/d	Pipeline imports	25.74	18.52	14.86	11.38	10.82	8.51	6.62
	Mexico	Bcf/d	Pipeline imports	3.93	4.45	4.98	5.29	5.53	5.77	6.03
	Canada	Bcf/d	Pipeline imports	2.35	1.73	1.72	1.42	1.4	1.48	1.44
	USA	Bcf/d	Pipeline imports	8.48	8.07	7.32	6.52	5.34	4.24	3.57
		Bcf/d	**Total**	**54.1**	**47.64**	**45.43**	**43.97**	**47.59**	**51.12**	**51**
S7–S6	ROW	Bcf/d	Consumption	0	0	0	0	0	0.45	0.52
	Australia + NZ	Bcf/d	Consumption	0	0	0	0	0	0.01	0.01
	LAC	Bcf/d	Consumption	0	0	0	0	0	0.23	0.29
	Africa	Bcf/d	Consumption	0	0	0	0	0	0.1	0.18
	C Asia + East Eur	Bcf/d	Consumption	0	0	0	0	0	0.07	0.07
	Russia	Bcf/d	Consumption	0	0	0	0	0	0.02	0.01
	China	Bcf/d	Consumption	0	0	0	0	0	0.18	0.09
	India	Bcf/d	Consumption	0	0	0	0	0	0.23	0.27
	Middle East	Bcf/d	Consumption	0	0	0	0	0	-0.01	-0.01
	EU	Bcf/d	Consumption	0	0	0	0	0	0.39	0.15
	Mexico	Bcf/d	Consumption	0	0	0	0	0	0	0.01
	Canada	Bcf/d	Consumption	0	0	0	0	0	0.01	0.01
	USA	Bcf/d	Consumption	0	0	0	0	0	-0.17	-0.25
		Bcf/d	**Total**	**0**	**0**	**0**	**0**	**0**	**1.53**	**1.37**
	ROW	Bcf/d	Production	0	0	0	0	0	-0.24	-0.47
	Australia + NZ	Bcf/d	Production	0	0	0	0	0	-0.03	-0.1
	LAC	Bcf/d	Production	0	0	0	0	0	-0.19	-0.36
	Africa	Bcf/d	Production	0	0	0	0	0	-0.39	-0.67
	C Asia + East Eur	Bcf/d	Production	0	0	0	0	0	-0.15	-0.35
	Russia	Bcf/d	Production	0	0	0	0	0	-0.32	-0.7
	China	Bcf/d	Production	0	0	0	0	0	-0.03	-0.05
	India	Bcf/d	Production	0	0	0	0	0	-0.2	-0.35
	Middle East	Bcf/d	Production	0	0	0	0	0	-0.42	-0.81
	EU	Bcf/d	Production	0	0	0	0	0	-0.16	-0.43
	Mexico	Bcf/d	Production	0	0	0	0	0	-0.01	-0.03
	Canada	Bcf/d	Production	0	0	0	0	0	-0.12	-0.23
	USA	Bcf/d	Production	0	0	0	0	0	3.79	5.92
		Bcf/d	**Total**	**0**	**0**	**0**	**0**	**0**	**1.53**	**1.37**
	ROW	Bcf/d	LNG exports	0	0	0	0	0	-0.18	-0.39
	Australia + NZ	Bcf/d	LNG exports	0	0	0	0	0	-0.04	-0.1
	LAC	Bcf/d	LNG exports	0	0	0	0	0	-0.09	-0.21
	Africa	Bcf/d	LNG exports	0	0	0	0	0	-0.16	-0.33

Scenario	Region	Unit	NG Volumes	2020	2025	2030	2035	2040	2045	2050
	C Asia + East Eur	Bcf/d	LNG exports	0	0	0	0	0	-0.11	-0.3
	Russia	Bcf/d	LNG exports	0	0	0	0	0	-0.04	-0.1
	China	Bcf/d	LNG exports	0	0	0	0	0	0	-0.01
	India	Bcf/d	LNG exports	0	0	0	0	0	-0.01	-0.02
	Middle East	Bcf/d	LNG exports	0	0	0	0	0	-0.27	-0.65
	EU	Bcf/d	LNG exports	0	0	0	0	0	-0.07	-0.19
	Mexico	Bcf/d	LNG exports	0	0	0	0	0	-0.01	-0.02
	Canada	Bcf/d	LNG exports	0	0	0	0	0	-0.13	-0.25
	USA	Bcf/d	LNG exports	0	0	0	0	0	4.03	6.25
		Bcf/d	**Total**	**0**	**0**	**0**	**0**	**0**	**2.92**	**3.69**
	ROW	Bcf/d	LNG imports	0	0	0	0	0	0.51	0.61
	Australia + NZ	Bcf/d	LNG imports	0	0	0	0	0	0	0.02
	LAC	Bcf/d	LNG imports	0	0	0	0	0	0.33	0.45
	Africa	Bcf/d	LNG imports	0	0	0	0	0	0.33	0.53
	C Asia + East Eur	Bcf/d	LNG imports	0	0	0	0	0	0.18	0.18
	Russia	Bcf/d	LNG imports	0	0	0	0	0	0.12	0.14
	China	Bcf/d	LNG imports	0	0	0	0	0	0.32	0.34
	India	Bcf/d	LNG imports	0	0	0	0	0	0.42	0.6
	Middle East	Bcf/d	LNG imports	0	0	0	0	0	0.16	0.16
	EU	Bcf/d	LNG imports	0	0	0	0	0	0.5	0.56
	Mexico	Bcf/d	LNG imports	0	0	0	0	0	0.04	0.06
	Canada	Bcf/d	LNG imports	0	0	0	0	0	0.02	0.03
	USA	Bcf/d	LNG imports	0	0	0	0	0	0.02	0.01
		Bcf/d	**Total**	**0**	**0**	**0**	**0**	**0**	**2.92**	**3.69**
	ROW	Bcf/d	Pipeline exports	0	0	0	0	0	-0.02	-0.02
	Australia + NZ	Bcf/d	Pipeline exports	0	0	0	0	0	0	0
	LAC	Bcf/d	Pipeline exports	0	0	0	0	0	-0.02	-0.04
	Africa	Bcf/d	Pipeline exports	0	0	0	0	0	-0.11	-0.19
	C Asia + East Eur	Bcf/d	Pipeline exports	0	0	0	0	0	0	0
	Russia	Bcf/d	Pipeline exports	0	0	0	0	0	-0.24	-0.53
	China	Bcf/d	Pipeline exports	0	0	0	0	0	0	0
	India	Bcf/d	Pipeline exports	0	0	0	0	0	0	0
	Middle East	Bcf/d	Pipeline exports	0	0	0	0	0	0	-0.01
	EU	Bcf/d	Pipeline exports	0	0	0	0	0	0	0
	Mexico	Bcf/d	Pipeline exports	0	0	0	0	0	0	-0.01
	Canada	Bcf/d	Pipeline exports	0	0	0	0	0	0	0
	USA	Bcf/d	Pipeline exports	0	0	0	0	0	0	0
		Bcf/d	**Total**	**0**	**0**	**0**	**0**	**0**	**-0.38**	**-0.8**
	ROW	Bcf/d	Pipeline imports	0	0	0	0	0	-0.01	-0.03
	Australia + NZ	Bcf/d	Pipeline imports	0	0	0	0	0	0	0
	LAC	Bcf/d	Pipeline imports	0	0	0	0	0	-0.02	-0.04
	Africa	Bcf/d	Pipeline imports	0	0	0	0	0	-0.11	-0.19
	C Asia + East Eur	Bcf/d	Pipeline imports	0	0	0	0	0	-0.06	-0.07
	Russia	Bcf/d	Pipeline imports	0	0	0	0	0	-0.05	-0.07
	China	Bcf/d	Pipeline imports	0	0	0	0	0	-0.12	-0.21
	India	Bcf/d	Pipeline imports	0	0	0	0	0	0	0
	Middle East	Bcf/d	Pipeline imports	0	0	0	0	0	-0.01	-0.01
	EU	Bcf/d	Pipeline imports	0	0	0	0	0	-0.01	-0.18
	Mexico	Bcf/d	Pipeline imports	0	0	0	0	0	-0.03	-0.04
	Canada	Bcf/d	Pipeline imports	0	0	0	0	0	-0.02	-0.03
	USA	Bcf/d	Pipeline imports	0	0	0	0	0	0.06	0.07
		Bcf/d	**Total**	**0**	**0**	**0**	**0**	**0**	**-0.38**	**-0.8**
	ROW	%	Consumption	0	0	0	0	0	0.98	1.14
	Australia + NZ	%	Consumption	0	0	0	0	0	1.77	1.61
	LAC	%	Consumption	0	0	0	0	0	0.99	1.18
	Africa	%	Consumption	0	0	0	0	0	0.31	0.47
	C Asia + East Eur	%	Consumption	0	0	0	0	0	0.24	0.24
	Russia	%	Consumption	0	0	0	0	0	0.05	0.05
	China	%	Consumption	0	0	0	0	0	0.27	0.14
	India	%	Consumption	0	0	0	0	0	0.67	0.68
	Middle East	%	Consumption	0	0	0	0	0	-0.01	-0.01
	EU	%	Consumption	0	0	0	0	0	1.33	0.52

Scenario	Region	Unit	NG Volumes	2020	2025	2030	2035	2040	2045	2050
	Mexico	%	Consumption	0	0	0	0	0	0	0.08
	Canada	%	Consumption	0	0	0	0	0	0.18	0.28
	USA	%	Consumption	0	0	0	0	0	-0.22	-0.33
		%	**Total**	**0**	**0**	**0**	**0**	**0**	**6.58**	**6.03**
	ROW	%	Production	0	0	0	0	0	-0.55	-1.08
	Australia + NZ	%	Production	0	0	0	0	0	-0.43	-1.88
	LAC	%	Production	0	0	0	0	0	-1.06	-1.89
	Africa	%	Production	0	0	0	0	0	-1.02	-1.58
	C Asia + East Eur	%	Production	0	0	0	0	0	-0.79	-1.79
	Russia	%	Production	0	0	0	0	0	-0.49	-1.13
	China	%	Production	0	0	0	0	0	-0.12	-0.21
	India	%	Production	0	0	0	0	0	-1.15	-1.7
	Middle East	%	Production	0	0	0	0	0	-0.66	-1.29
	EU	%	Production	0	0	0	0	0	-1.26	-2.96
	Mexico	%	Production	0	0	0	0	0	-0.32	-0.69
	Canada	%	Production	0	0	0	0	0	-0.75	-1.54
	USA	%	Production	0	0	0	0	0	3.47	5.48
		%	**Total**	**0**	**0**	**0**	**0**	**0**	**-5.14**	**-12.24**
	ROW	%	LNG exports	0	0	0	0	0	-1.14	-2.37
	Australia + NZ	%	LNG exports	0	0	0	0	0	-0.65	-2.12
	LAC	%	LNG exports	0	0	0	0	0	-1.81	-3.52
	Africa	%	LNG exports	0	0	0	0	0	-1.32	-2.8
	C Asia + East Eur	%	LNG exports	0	0	0	0	0	-3.04	-5.99
	Russia	%	LNG exports	0	0	0	0	0	-1.38	-4.11
	China	%	LNG exports	0	0	0	0	0	-6.48	-8.66
	India	%	LNG exports	0	0	0	0	0	-3.69	-6.53
	Middle East	%	LNG exports	0	0	0	0	0	-1.49	-3.43
	EU	%	LNG exports	0	0	0	0	0	-3.01	-6.22
	Mexico	%	LNG exports	0	0	0	0	0	-4.8	-7.91
	Canada	%	LNG exports	0	0	0	0	0	-1.41	-2.6
	USA	%	LNG exports	0	0	0	0	0	14.76	22.87
		%	**Total**	**0**	**0**	**0**	**0**	**0**	**-15.45**	**-33.37**
	ROW	%	LNG imports	0	0	0	0	0	2.42	3.2
	Australia + NZ	%	LNG imports	0	0	0	0	0	2.49	11.73
	LAC	%	LNG imports	0	0	0	0	0	3.04	3.79
	Africa	%	LNG imports	0	0	0	0	0	5.19	6.42
	C Asia + East Eur	%	LNG imports	0	0	0	0	0	1.65	1.8
	Russia	%	LNG imports	0	0	0	0	0	3.48	4.22
	China	%	LNG imports	0	0	0	0	0	1.61	1.74
	India	%	LNG imports	0	0	0	0	0	2.34	3.03
	Middle East	%	LNG imports	0	0	0	0	0	11.5	11.86
	EU	%	LNG imports	0	0	0	0	0	4.61	5.33
	Mexico	%	LNG imports	0	0	0	0	0	2.8	4.39
	Canada	%	LNG imports	0	0	0	0	0	14.16	15.65
	USA	%	LNG imports	0	0	0	0	0	20.21	17.02
		%	**Total**	**0**	**0**	**0**	**0**	**0**	**75.51**	**90.16**
	ROW	%	Pipeline exports	0	0	0	0	0	-0.65	-1.58
	Australia + NZ	%	Pipeline exports	0	0	0	0	0	-0.61	-2.03
	LAC	%	Pipeline exports	0	0	0	0	0	-2	-3.93
	Africa	%	Pipeline exports	0	0	0	0	0	-2.85	-3.32
	C Asia + East Eur	%	Pipeline exports	0	0	0	0	0	0.56	0.6
	Russia	%	Pipeline exports	0	0	0	0	0	-0.73	-1.66
	China	%	Pipeline exports	0	0	0	0	0	-7.94	-9.38
	India	%	Pipeline exports	0	0	0	0	0	-7.94	-9.28
	Middle East	%	Pipeline exports	0	0	0	0	0	-3.24	-4.39
	EU	%	Pipeline exports	0	0	0	0	0	-0.66	-1.62
	Mexico	%	Pipeline exports	0	0	0	0	0	-1.05	-1.83
	Canada	%	Pipeline exports	0	0	0	0	0	0.06	0.1
	USA	%	Pipeline exports	0	0	0	0	0	0	0
		%	**Total**	**0**	**0**	**0**	**0**	**0**	**-27.06**	**-38.34**
	ROW	%	Pipeline imports	0	0	0	0	0	-1.75	-3.55
	Australia + NZ	%	Pipeline imports	0	0	0	0	0	1.73	-7.8

Scenario	Region	Unit	NG Volumes	2020	2025	2030	2035	2040	2045	2050
	LAC	%	Pipeline imports	0	0	0	0	0	-2	-3.93
	Africa	%	Pipeline imports	0	0	0	0	0	-3.05	-3.4
	C Asia + East Eur	%	Pipeline imports	0	0	0	0	0	-1.52	-2.07
	Russia	%	Pipeline imports	0	0	0	0	0	-2.22	-2.76
	China	%	Pipeline imports	0	0	0	0	0	-0.58	-1.01
	India	%	Pipeline imports	0	0	0	0	0	-2.08	-3.14
	Middle East	%	Pipeline imports	0	0	0	0	0	-8.29	-8.39
	EU	%	Pipeline imports	0	0	0	0	0	-0.09	-2.62
	Mexico	%	Pipeline imports	0	0	0	0	0	-0.57	-0.73
	Canada	%	Pipeline imports	0	0	0	0	0	-1.48	-1.91
	USA	%	Pipeline imports	0	0	0	0	0	1.32	1.98
		%	**Total**	**0**	**0**	**0**	**0**	**0**	**-20.58**	**-39.33**

Table D-11. Changes in natural gas consumption, production, and trade by region: S6 vs. S1 and S7 vs. S2 (see Figure 11)

Scenario	Region	Unit	NG Volumes	2020	2025	2030	2035	2040	2045	2050
S6–S1	LAC	Bcf/d	Consumption	0	0.04	-0.53	-2.78	-4.14	-6.58	-8.15
	Africa	Bcf/d	Consumption	0	0.02	-0.11	-1.23	-1.71	-1.57	-2.68
	C Asia + East Eur	Bcf/d	Consumption	-0.01	0.06	-0.11	-3.41	-6.58	-11.55	-16.18
	Russia	Bcf/d	Consumption	0	0.05	-0.03	-0.02	-0.49	-3.83	-6.71
	China	Bcf/d	Consumption	0	0.32	-1.21	-3.09	-2.44	-2.53	-9.03
	India	Bcf/d	Consumption	0	-0.33	-0.79	-1.33	-0.71	-0.01	-0.81
	Middle East	Bcf/d	Consumption	-0.12	-0.89	-0.43	-5.48	-10.13	-16.09	-22.4
	EU	Bcf/d	Consumption	0	-0.83	-4.67	-5.11	-1.97	-3.06	-8.08
	Mexico	Bcf/d	Consumption	0	0.13	0.14	-0.89	-2.09	-3.12	-3.91
	Canada	Bcf/d	Consumption	0	0.27	-0.04	-1.17	-1.47	-1.29	-1
	USA	Bcf/d	Consumption	0.02	-7.2	-11.46	-13.94	-15.94	-28.82	-43.33
		Bcf/d	**Total**	**-0.11**	**-8.76**	**-22.07**	**-44.84**	**-54.69**	**-86.34**	**-132.96**
	ROW	Bcf/d	Production	0	-0.3	-2.2	-4	-4.31	-4.49	-5.2
	Australia + NZ	Bcf/d	Production	0	0	-0.02	-0.25	-0.45	-0.74	-1.28
	LAC	Bcf/d	Production	0	-0.11	-0.24	-1.79	-3.08	-4.81	-6.34
	Africa	Bcf/d	Production	0	-0.05	-0.43	-1.92	-3.31	-4.26	-6.06
	C Asia + East Eur	Bcf/d	Production	0	-0.05	-0.04	-1.92	-4.17	-7.18	-10.34
	Russia	Bcf/d	Production	0	-0.17	-0.33	-1.65	-3.79	-8.88	-18.18
	China	Bcf/d	Production	0	-0.12	-0.33	-1.16	-1.16	-1.27	-3.46
	India	Bcf/d	Production	0	-0.16	-0.12	-0.44	-0.71	-0.64	-1.53
	Middle East	Bcf/d	Production	-0.12	-0.83	-1.09	-6.45	-11.3	-17.55	-24.84
	EU	Bcf/d	Production	0	-0.18	-1.67	-1.91	-1.19	-2.78	-6.44
	Mexico	Bcf/d	Production	0	-0.16	-0.21	-0.71	-1.18	-1.84	-2.5
	Canada	Bcf/d	Production	0	0.06	-0.3	-1.3	-1.89	-2.57	-3.08
	USA	Bcf/d	Production	0.01	-6.68	-15.09	-21.35	-18.15	-29.33	-43.7
		Bcf/d	**Total**	**-0.12**	**-8.76**	**-22.06**	**-44.86**	**-54.69**	**-86.34**	**-132.96**
	ROW	Bcf/d	LNG exports	0	-0.05	-0.3	-0.41	-0.93	-1.87	-2.85
	Australia + NZ	Bcf/d	LNG exports	0	-0.02	-0.08	-0.21	-0.39	-0.61	-1.11
	LAC	Bcf/d	LNG exports	0	-0.03	-0.21	-0.45	-0.68	-1.07	-1.68
	Africa	Bcf/d	LNG exports	0	-0.04	-0.3	-0.87	-1.5	-2.47	-3.55
	C Asia + East Eur	Bcf/d	LNG exports	0	-0.01	-0.09	-0.26	-0.58	-1.28	-2.48
	Russia	Bcf/d	LNG exports	0	-0.01	-0.01	-0.11	-0.25	-0.53	-0.97
	China	Bcf/d	LNG exports	0	0	-0.01	0	-0.02	-0.04	-0.06
	India	Bcf/d	LNG exports	0	0	0	-0.02	-0.05	-0.14	-0.27
	Middle East	Bcf/d	LNG exports	0	0	-0.73	-1.35	-1.6	-2.4	-3.88
	EU	Bcf/d	LNG exports	0	0.01	-0.02	-0.12	-0.39	-0.96	-1.43
	Mexico	Bcf/d	LNG exports	0	0	0	-0.01	-0.02	-0.06	-0.12
	Canada	Bcf/d	LNG exports	0	0	-0.23	-0.31	-0.53	-1.04	-1.66
	USA	Bcf/d	LNG exports	0	0	-4.1	-7.3	-1.54	0	0
		Bcf/d	**Total**	**0**	**-0.16**	**-6.08**	**-11.42**	**-8.47**	**-12.48**	**-20.07**
	ROW	Bcf/d	LNG imports	0	-0.34	-1.9	-3.61	-3.66	-5.09	-8.01
	Australia + NZ	Bcf/d	LNG imports	0	0	0	0	0	0	-0.03
	LAC	Bcf/d	LNG imports	0	0.13	-0.5	-1.45	-1.74	-2.84	-3.48
	Africa	Bcf/d	LNG imports	0	0.01	-0.12	-0.3	0.08	0.18	-0.23

Scenario	Region	Unit	NG Volumes	2020	2025	2030	2035	2040	2045	2050
	C Asia + East Eur	Bcf/d	LNG imports	0	0.1	-0.23	-1.3	-1.59	-2.86	-3.94
	Russia	Bcf/d	LNG imports	0	0	0	0	0.38	0.2	0.04
	China	Bcf/d	LNG imports	0	0.38	-0.56	-0.91	-0.1	0.06	-0.27
	India	Bcf/d	LNG imports	-0.01	-0.17	-0.67	-0.92	-0.05	0.5	0.45
	Middle East	Bcf/d	LNG imports	0	-0.05	-0.09	-0.37	-0.36	-0.77	-1.14
	EU	Bcf/d	LNG imports	0	-0.21	-1.93	-2.28	-1.05	-1.24	-2.72
	Mexico	Bcf/d	LNG imports	0	0.01	-0.04	-0.21	-0.33	-0.5	-0.64
	Canada	Bcf/d	LNG imports	0	0	0	-0.02	-0.06	-0.08	-0.07
	USA	Bcf/d	LNG imports	0	-0.02	-0.05	-0.04	0.02	-0.02	-0.02
		Bcf/d	**Total**	**-0.03**	**-0.14**	**-6.1**	**-11.42**	**-8.46**	**-12.47**	**-20.05**
	ROW	Bcf/d	Pipeline exports	0	-0.14	-0.96	-1	-0.2	-0.03	0.03
	Australia + NZ	Bcf/d	Pipeline exports	0	0	0	0	0	0	0
	LAC	Bcf/d	Pipeline exports	0	-0.01	0.02	-0.07	-0.16	-0.25	-0.31
	Africa	Bcf/d	Pipeline exports	0	-0.02	-0.12	-0.14	-0.04	0.35	0.97
	C Asia + East Eur	Bcf/d	Pipeline exports	0	0	-0.01	-0.01	0	0	0
	Russia	Bcf/d	Pipeline exports	0	-0.21	-0.29	-1.52	-2.88	-5	-11.63
	China	Bcf/d	Pipeline exports	0	0	0	0	0	0	0
	India	Bcf/d	Pipeline exports	0	0	0	0	0	0	0
	Middle East	Bcf/d	Pipeline exports	0	0	-0.01	0	0.01	0.02	0.03
	EU	Bcf/d	Pipeline exports	0	-0.03	-0.23	-0.22	-0.03	-0.03	-0.04
	Mexico	Bcf/d	Pipeline exports	0	0	0	-0.02	-0.07	-0.18	-0.27
	Canada	Bcf/d	Pipeline exports	0	-0.14	-0.03	-0.08	-0.31	-0.51	-0.58
	USA	Bcf/d	Pipeline exports	0	0	0	0	0.01	0	0
		Bcf/d	**Total**	**0.01**	**-0.55**	**-1.63**	**-3.06**	**-3.67**	**-5.64**	**-11.79**
	ROW	Bcf/d	Pipeline imports	0	-0.01	-0.05	-0.11	-0.1	-0.06	-0.1
	Australia + NZ	Bcf/d	Pipeline imports	0	0	0	0	0	0	0
	LAC	Bcf/d	Pipeline imports	0	-0.01	0.02	-0.07	-0.16	-0.25	-0.31
	Africa	Bcf/d	Pipeline imports	0	0	0.02	0	-0.01	0.37	1.05
	C Asia + East Eur	Bcf/d	Pipeline imports	0	0	0.06	-0.47	-1.4	-2.79	-4.39
	Russia	Bcf/d	Pipeline imports	0	0	0	-0.01	-0.22	-0.7	-1.18
	China	Bcf/d	Pipeline imports	0	0.06	-0.33	-1.02	-1.2	-1.36	-5.35
	India	Bcf/d	Pipeline imports	0	0	0	0	0	0	0
	Middle East	Bcf/d	Pipeline imports	0	0	0	-0.02	-0.06	-0.15	-0.27
	EU	Bcf/d	Pipeline imports	0	-0.47	-1.32	-1.27	-0.14	-0.02	-0.38
	Mexico	Bcf/d	Pipeline imports	0	0.27	0.38	0	-0.67	-1	-1.15
	Canada	Bcf/d	Pipeline imports	0	0.07	0	-0.24	-0.35	-0.2	-0.09
	USA	Bcf/d	Pipeline imports	0	-0.49	-0.41	0.14	0.64	0.52	0.4
		Bcf/d	**Total**	**-0.01**	**-0.57**	**-1.63**	**-3.07**	**-3.68**	**-5.63**	**-11.76**
S7–S2	ROW	Bcf/d	Consumption	0	-0.45	-2.88	-6.17	-7.9	-8.81	-11.81
	Australia + NZ	Bcf/d	Consumption	0	0.02	0.06	-0.03	-0.08	-0.14	-0.21
	LAC	Bcf/d	Consumption	0	0.04	-0.53	-2.7	-4.71	-7.19	-8.78
	Africa	Bcf/d	Consumption	0	0.02	-0.11	-1.22	-1.87	-1.86	-3.06
	C Asia + East Eur	Bcf/d	Consumption	-0.01	0.06	-0.11	-3.34	-6.97	-11.89	-16.51
	Russia	Bcf/d	Consumption	0	0.05	-0.03	-0.01	-0.55	-3.89	-6.76
	China	Bcf/d	Consumption	0	0.32	-1.21	-2.79	-3.36	-3.02	-9.49
	India	Bcf/d	Consumption	0	-0.33	-0.79	-1.23	-1.3	-0.64	-1.52
	Middle East	Bcf/d	Consumption	-0.12	-0.89	-0.43	-5.49	-10.09	-16.08	-22.45
	EU	Bcf/d	Consumption	0	-0.83	-4.67	-4.66	-3.73	-4.21	-9.42
	Mexico	Bcf/d	Consumption	0	0.13	0.14	-0.89	-2.09	-3.14	-3.92
	Canada	Bcf/d	Consumption	0	0.27	-0.04	-1.18	-1.48	-1.38	-1.11
	USA	Bcf/d	Consumption	0.02	-7.2	-11.46	-14	-15.52	-27.81	-40.36
		Bcf/d	**Total**	**-0.11**	**-8.76**	**-22.07**	**-43.71**	**-59.65**	**-90.04**	**-135.4**
	ROW	Bcf/d	Production	0	-0.3	-2.2	-3.96	-4.08	-3.89	-4.63
	Australia + NZ	Bcf/d	Production	0	0	-0.02	-0.25	-0.42	-0.6	-1.03
	LAC	Bcf/d	Production	0	-0.11	-0.24	-1.83	-2.69	-4.07	-5.48
	Africa	Bcf/d	Production	0	-0.05	-0.43	-1.95	-2.84	-3.43	-5.12
	C Asia + East Eur	Bcf/d	Production	0	-0.05	-0.04	-1.95	-3.91	-6.5	-9.41
	Russia	Bcf/d	Production	0	-0.17	-0.33	-1.67	-3.34	-7.57	-16.67
	China	Bcf/d	Production	0	-0.12	-0.33	-1.11	-1.3	-1.27	-3.43
	India	Bcf/d	Production	0	-0.16	-0.12	-0.46	-0.59	-0.43	-1.26
	Middle East	Bcf/d	Production	-0.12	-0.83	-1.09	-6.46	-10.75	-16.27	-23.3
	EU	Bcf/d	Production	0	-0.18	-1.67	-1.76	-1.8	-2.52	-5.99

Scenario	Region	Unit	NG Volumes	2020	2025	2030	2035	2040	2045	2050
	Mexico	Bcf/d	Production	0	-0.16	-0.21	-0.71	-1.18	-1.81	-2.47
	Canada	Bcf/d	Production	0	0.06	-0.3	-1.29	-1.81	-2.23	-2.71
	USA	Bcf/d	Production	0.01	-6.68	-15.09	-20.34	-24.97	-39.46	-53.91
		Bcf/d	**Total**	**-0.12**	**-8.76**	**-22.06**	**-43.73**	**-59.66**	**-90.03**	**-135.41**
	ROW	Bcf/d	LNG exports	0	-0.05	-0.3	-0.43	-0.76	-1.31	-2.21
	Australia + NZ	Bcf/d	LNG exports	0	-0.02	-0.08	-0.21	-0.34	-0.46	-0.86
	LAC	Bcf/d	LNG exports	0	-0.03	-0.21	-0.44	-0.6	-0.8	-1.3
	Africa	Bcf/d	LNG exports	0	-0.04	-0.3	-0.87	-1.33	-1.9	-2.84
	C Asia + East Eur	Bcf/d	LNG exports	0	-0.01	-0.09	-0.26	-0.51	-0.88	-1.85
	Russia	Bcf/d	LNG exports	0	-0.01	-0.01	-0.11	-0.21	-0.39	-0.74
	China	Bcf/d	LNG exports	0	0	-0.01	0	-0.01	-0.02	-0.04
	India	Bcf/d	LNG exports	0	0	0	-0.02	-0.04	-0.1	-0.21
	Middle East	Bcf/d	LNG exports	0	0	-0.73	-1.31	-1.4	-1.48	-2.66
	EU	Bcf/d	LNG exports	0	0.01	-0.02	-0.12	-0.31	-0.65	-1.06
	Mexico	Bcf/d	LNG exports	0	0	0	-0.01	-0.01	-0.03	-0.09
	Canada	Bcf/d	LNG exports	0	0	-0.23	-0.3	-0.41	-0.58	-1.11
	USA	Bcf/d	LNG exports	0	0	-4.1	-6.19	-9.05	-11.49	-13.64
		Bcf/d	**Total**	**0**	**-0.16**	**-6.08**	**-10.27**	**-15**	**-20.09**	**-28.61**
	ROW	Bcf/d	LNG imports	0	-0.34	-1.9	-3.45	-4.66	-6.21	-9.27
	Australia + NZ	Bcf/d	LNG imports	0	0	0	0	0	0	-0.04
	LAC	Bcf/d	LNG imports	0	0.13	-0.5	-1.32	-2.63	-3.91	-4.61
	Africa	Bcf/d	LNG imports	0	0.01	-0.12	-0.25	-0.38	-0.36	-0.84
	C Asia + East Eur	Bcf/d	LNG imports	0	0.1	-0.23	-1.16	-2.41	-3.96	-5.16
	Russia	Bcf/d	LNG imports	0	0	0	0.06	0.03	-0.27	-0.47
	China	Bcf/d	LNG imports	0	0.38	-0.56	-0.71	-0.75	-0.63	-1.08
	India	Bcf/d	LNG imports	-0.01	-0.17	-0.67	-0.78	-0.75	-0.32	-0.47
	Middle East	Bcf/d	LNG imports	0	-0.05	-0.09	-0.33	-0.69	-1.15	-1.56
	EU	Bcf/d	LNG imports	0	-0.21	-1.93	-2.07	-2.15	-2.35	-3.98
	Mexico	Bcf/d	LNG imports	0	0.01	-0.04	-0.2	-0.46	-0.71	-0.91
	Canada	Bcf/d	LNG imports	0	0	0	-0.02	-0.12	-0.16	-0.15
	USA	Bcf/d	LNG imports	0	-0.02	-0.05	-0.03	-0.03	-0.06	-0.08
		Bcf/d	**Total**	**-0.03**	**-0.14**	**-6.1**	**-10.27**	**-14.99**	**-20.09**	**-28.62**
	ROW	Bcf/d	Pipeline exports	0	-0.14	-0.96	-0.92	-0.17	-0.03	0.03
	Australia + NZ	Bcf/d	Pipeline exports	0	0	0	0	0	0	0
	LAC	Bcf/d	Pipeline exports	0	-0.01	0.02	-0.08	-0.1	-0.17	-0.22
	Africa	Bcf/d	Pipeline exports	0	-0.02	-0.12	-0.14	0.06	0.44	1.06
	C Asia + East Eur	Bcf/d	Pipeline exports	0	0	-0.01	-0.01	0	0	0
	Russia	Bcf/d	Pipeline exports	0	-0.21	-0.29	-1.51	-2.62	-4.05	-10.54
	China	Bcf/d	Pipeline exports	0	0	0	0	0	0	0
	India	Bcf/d	Pipeline exports	0	0	0	0	0	0	0
	Middle East	Bcf/d	Pipeline exports	0	0	-0.01	0	0.01	0.01	0.04
	EU	Bcf/d	Pipeline exports	0	-0.03	-0.23	-0.2	-0.03	-0.02	-0.02
	Mexico	Bcf/d	Pipeline exports	0	0	0	-0.02	-0.07	-0.18	-0.3
	Canada	Bcf/d	Pipeline exports	0	-0.14	-0.03	-0.08	-0.33	-0.57	-0.67
	USA	Bcf/d	Pipeline exports	0	0	0	0	0	0	0
		Bcf/d	**Total**	**0.01**	**-0.55**	**-1.63**	**-2.96**	**-3.23**	**-4.56**	**-10.62**
	ROW	Bcf/d	Pipeline imports	0	-0.01	-0.05	-0.11	-0.1	-0.05	-0.08
	Australia + NZ	Bcf/d	Pipeline imports	0	0	0	0	0	0	0
	LAC	Bcf/d	Pipeline imports	0	-0.01	0.02	-0.08	-0.1	-0.17	-0.22
	Africa	Bcf/d	Pipeline imports	0	0	0.02	-0.02	0.09	0.48	1.12
	C Asia + East Eur	Bcf/d	Pipeline imports	0	0	0.06	-0.5	-1.16	-2.3	-3.79
	Russia	Bcf/d	Pipeline imports	0	0	0	-0.02	-0.08	-0.48	-0.91
	China	Bcf/d	Pipeline imports	0	0.06	-0.33	-0.97	-1.33	-1.14	-5.03
	India	Bcf/d	Pipeline imports	0	0	0	0	0	0	0
	Middle East	Bcf/d	Pipeline imports	0	0	0	-0.02	-0.04	-0.11	-0.21
	EU	Bcf/d	Pipeline imports	0	-0.47	-1.32	-1.15	-0.12	-0.02	-0.54
	Mexico	Bcf/d	Pipeline imports	0	0.27	0.38	-0.03	-0.54	-0.83	-0.91
	Canada	Bcf/d	Pipeline imports	0	0.07	0	-0.25	-0.29	-0.14	-0.03
	USA	Bcf/d	Pipeline imports	0	-0.49	-0.41	0.17	0.43	0.22	-0.02
		Bcf/d	**Total**	**-0.01**	**-0.57**	**-1.63**	**-2.97**	**-3.23**	**-4.54**	**-10.63**

Scenario	Region	Unit	NG Volumes	2020	2025	2030	2035	2040	2045	2050
S6–S1	ROW	%	Consumption	0.00	-1.11	-6.34	-12.92	-13.64	-14.35	-18.74
	Australia + NZ	%	Consumption	0.00	6.45	13.95	-10.53	-13.73	-17.11	-18.02
	LAC	%	Consumption	0.00	0.24	-2.68	-11.87	-15.49	-21.84	-24.65
	Africa	%	Consumption	0.00	0.14	-0.64	-5.73	-6.39	-4.69	-6.47
	C Asia + East Eur	%	Consumption	-0.03	0.20	-0.34	-9.54	-16.86	-27.47	-36.46
	Russia	%	Consumption	0.00	0.14	-0.08	-0.05	-1.23	-9.60	-16.86
	China	%	Consumption	0.00	0.77	-2.53	-5.58	-3.95	-3.68	-12.21
	India	%	Consumption	0.00	-2.78	-4.60	-5.81	-2.50	-0.03	-1.97
	Middle East	%	Consumption	-0.26	-1.93	-0.90	-10.59	-17.79	-25.47	-32.99
	EU	%	Consumption	0.00	-2.32	-13.96	-17.04	-6.83	-9.36	-22.16
	Mexico	%	Consumption	0.00	1.61	1.50	-8.32	-17.30	-23.28	-26.53
	Canada	%	Consumption	0.00	3.38	-0.48	-14.83	-19.71	-18.91	-16.72
	USA	%	Consumption	0.02	-8.73	-13.03	-15.44	-16.71	-27.01	-36.41
		%	**Total**	**-0.03**	**-2.36**	**-5.43**	**-10.22**	**-11.52**	**-16.40**	**-23.13**
	ROW	%	Production	0.00	-0.79	-5.10	-8.74	-9.25	-9.38	-10.69
	Australia + NZ	%	Production	0.00	0.00	-0.17	-2.25	-4.68	-9.46	-19.42
	LAC	%	Production	0.00	-0.80	-1.51	-10.03	-15.45	-21.18	-24.94
	Africa	%	Production	0.00	-0.20	-1.56	-6.10	-9.04	-10.03	-12.52
	C Asia + East Eur	%	Production	0.00	-0.28	-0.21	-9.34	-17.84	-26.86	-34.32
	Russia	%	Production	0.00	-0.28	-0.52	-2.60	-5.59	-11.97	-22.69
	China	%	Production	0.00	-0.61	-1.47	-4.66	-4.40	-4.60	-12.24
	India	%	Production	0.00	-3.26	-1.68	-4.44	-5.31	-3.63	-6.87
	Middle East	%	Production	-0.20	-1.42	-1.79	-9.71	-15.48	-21.60	-28.25
	EU	%	Production	0.00	-1.79	-16.39	-19.45	-11.64	-17.58	-30.87
	Mexico	%	Production	0.00	-6.27	-6.27	-18.16	-26.34	-34.33	-38.70
	Canada	%	Production	0.00	0.43	-2.06	-8.53	-11.21	-14.10	-17.00
	USA	%	Production	0.01	-6.99	-14.06	-18.05	-14.35	-21.13	-28.82
		%	**Total**	**-0.03**	**-2.36**	**-5.43**	**-10.23**	**-11.52**	**-16.40**	**-23.13**
	ROW	%	LNG exports	0.00	-0.45	-2.17	-2.63	-5.66	-10.38	-14.88
	Australia + NZ	%	LNG exports	0.00	-0.17	-0.68	-1.96	-4.28	-8.63	-19.61
	LAC	%	LNG exports	0.00	-1.36	-7.87	-12.82	-14.44	-17.07	-22.08
	Africa	%	LNG exports	0.00	-0.38	-2.59	-6.98	-11.03	-16.72	-23.23
	C Asia + East Eur	%	LNG exports	0.00	-5.88	-21.43	-24.30	-23.02	-26.23	-33.02
	Russia	%	LNG exports	0.00	-0.26	-0.26	-3.00	-7.49	-16.31	-27.95
	China	%	LNG exports	0.00	0.00	-100.00	0.00	-33.33	-36.36	-40.00
	India	%	LNG exports	0.00	0.00	0.00	-22.22	-25.00	-34.15	-42.19
	Middle East	%	LNG exports	0.00	0.00	-5.21	-8.57	-9.03	-11.74	-16.94
	EU	%	LNG exports	0.00	2.17	-3.17	-13.79	-23.21	-30.28	-31.78
	Mexico	%	LNG exports	0.00	0.00	0.00	-33.33	-22.22	-30.00	-35.29
	Canada	%	LNG exports	0.00	0.00	-8.68	-7.06	-7.18	-10.35	-14.89
	USA	%	LNG exports	0.00	0.00	-21.75	-28.10	-5.63	0.00	0.00
		%	**Total**	**0.00**	**-0.23**	**-7.57**	**-12.13**	**-8.13**	**-10.76**	**-15.97**
	ROW	%	LNG imports	0.00	-1.68	-8.53	-15.11	-14.88	-19.61	-29.72
	Australia + NZ	%	LNG imports	0.00	0.00	0.00	0.00	0.00	0.00	-16.67
	LAC	%	LNG imports	0.00	2.64	-7.62	-15.95	-15.14	-20.75	-22.83
	Africa	%	LNG imports	0.00	0.86	-6.15	-9.55	1.85	2.96	-2.73
	C Asia + East Eur	%	LNG imports	0.00	1.25	-2.51	-11.66	-12.67	-21.01	-27.77
	Russia	%	LNG imports	0.00	0.00	0.00	0.00	14.50	6.39	1.20
	China	%	LNG imports	0.00	2.43	-3.15	-4.71	-0.51	0.30	-1.36
	India	%	LNG imports	-0.25	-2.43	-6.63	-7.03	-0.33	2.88	2.31
	Middle East	%	LNG imports	0.00	-10.42	-14.29	-34.58	-23.38	-36.15	-45.24
	EU	%	LNG imports	0.00	-2.37	-20.96	-23.63	-10.25	-10.32	-20.64
	Mexico	%	LNG imports	0.00	0.75	-2.78	-13.38	-20.12	-28.25	-32.82
	Canada	%	LNG imports	0.00	0.00	0.00	-14.29	-31.58	-32.00	-26.92
	USA	%	LNG imports	0.00	-7.69	-21.74	-22.22	20.00	-20.00	-20.00
		%	**Total**	**-0.05**	**-0.20**	**-7.60**	**-12.13**	**-8.12**	**-10.75**	**-15.95**
	ROW	%	Pipeline exports	0.00	-1.86	-13.62	-16.53	-4.33	-1.12	1.97
	Australia + NZ	%	Pipeline exports	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	LAC	%	Pipeline exports	0.00	-0.55	1.12	-4.38	-11.76	-20.49	-25.20
	Africa	%	Pipeline exports	0.00	-1.77	-9.76	-8.86	-1.70	10.36	20.21
	C Asia + East Eur	%	Pipeline exports	0.00	0.00	-20.00	-25.00	0.00	0.00	0.00
	Russia	%	Pipeline exports	0.00	-0.97	-1.36	-6.57	-9.83	-13.47	-26.56

Scenario	Region	Unit	NG Volumes	2020	2025	2030	2035	2040	2045	2050
	China	%	Pipeline exports	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	India	%	Pipeline exports	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Middle East	%	Pipeline exports	0.00	0.00	-33.33	0.00	25.00	33.33	33.33
	EU	%	Pipeline exports	0.00	-1.86	-15.44	-17.60	-3.26	-6.12	-14.81
	Mexico	%	Pipeline exports	0.00	0.00	0.00	-40.00	-46.67	-51.43	-48.21
	Canada	%	Pipeline exports	0.00	-2.39	-0.54	-1.68	-7.81	-15.45	-20.64
	USA	%	Pipeline exports	0.00	0.00	0.00	0.00	0.12	0.00	0.00
		%	**Total**	**0.02**	**-1.14**	**-3.46**	**-6.51**	**-7.16**	**-9.87**	**-18.54**
	ROW	%	Pipeline imports	0.00	-1.20	-5.49	-12.50	-12.50	-7.50	-10.20
	Australia + NZ	%	Pipeline imports	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	LAC	%	Pipeline imports	0.00	-0.55	1.12	-4.38	-11.76	-20.49	-25.20
	Africa	%	Pipeline imports	0.00	0.00	5.71	0.00	-0.55	11.90	22.44
	C Asia + East Eur	%	Pipeline imports	0.00	0.00	1.17	-9.09	-24.82	-42.21	-57.84
	Russia	%	Pipeline imports	0.00	0.00	0.00	-0.73	-10.38	-23.33	-32.60
	China	%	Pipeline imports	0.00	1.01	-4.38	-9.16	-7.60	-6.36	-20.60
	India	%	Pipeline imports	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Middle East	%	Pipeline imports	0.00	0.00	0.00	-33.33	-42.86	-51.72	-60.00
	EU	%	Pipeline imports	0.00	-2.47	-8.16	-10.04	-1.28	-0.23	-5.29
	Mexico	%	Pipeline imports	0.00	6.46	8.26	0.00	-10.81	-14.68	-15.91
	Canada	%	Pipeline imports	0.00	4.22	0.00	-14.46	-20.00	-11.76	-5.77
	USA	%	Pipeline imports	0.00	-5.72	-5.30	2.19	13.62	14.17	12.86
		%	**Total**	**-0.02**	**-1.18**	**-3.46**	**-6.53**	**-7.18**	**-9.85**	**-18.49**
S7–S2	ROW	%	Consumption	0.00	-1.11	-6.34	-12.65	-15.22	-15.89	-20.45
	Australia + NZ	%	Consumption	0.00	6.45	13.95	-8.11	-15.38	-17.95	-18.58
	LAC	%	Consumption	0.00	0.24	-2.68	-11.57	-17.26	-23.22	-25.84
	Africa	%	Consumption	0.00	0.14	-0.64	-5.69	-6.94	-5.49	-7.29
	C Asia + East Eur	%	Consumption	-0.03	0.20	-0.34	-9.36	-17.69	-28.00	-36.87
	Russia	%	Consumption	0.00	0.14	-0.08	-0.03	-1.38	-9.73	-16.95
	China	%	Consumption	0.00	0.77	-2.53	-5.07	-5.36	-4.35	-12.74
	India	%	Consumption	0.00	-2.78	-4.60	-5.40	-4.49	-1.80	-3.61
	Middle East	%	Consumption	-0.26	-1.93	-0.90	-10.61	-17.74	-25.47	-33.04
	EU	%	Consumption	0.00	-2.32	-13.96	-15.78	-12.19	-12.29	-24.82
	Mexico	%	Consumption	0.00	1.61	1.50	-8.32	-17.30	-23.40	-26.56
	Canada	%	Consumption	0.00	3.38	-0.48	-14.94	-19.81	-19.94	-18.17
	USA	%	Consumption	0.02	-8.73	-13.03	-15.49	-16.34	-26.35	-34.86
		%	**Total**	**-0.03**	**-2.36**	**-5.43**	**-9.99**	**-12.44**	**-16.93**	**-23.40**
	ROW	%	Production	0.00	-0.79	-5.10	-8.66	-8.80	-8.27	-9.72
	Australia + NZ	%	Production	0.00	0.00	-0.17	-2.25	-4.38	-7.84	-16.51
	LAC	%	Production	0.00	-0.80	-1.51	-10.23	-13.76	-18.69	-22.64
	Africa	%	Production	0.00	-0.20	-1.56	-6.18	-7.86	-8.32	-10.94
	C Asia + East Eur	%	Production	0.00	-0.28	-0.21	-9.47	-16.91	-25.10	-32.62
	Russia	%	Production	0.00	-0.28	-0.52	-2.63	-4.96	-10.44	-21.40
	China	%	Production	0.00	-0.61	-1.47	-4.47	-4.91	-4.61	-12.18
	India	%	Production	0.00	-3.26	-1.68	-4.64	-4.45	-2.50	-5.82
	Middle East	%	Production	-0.20	-1.42	-1.79	-9.73	-14.84	-20.46	-27.22
	EU	%	Production	0.00	-1.79	-16.39	-18.20	-16.62	-16.37	-29.98
	Mexico	%	Production	0.00	-6.27	-6.27	-18.16	-26.34	-34.09	-38.59
	Canada	%	Production	0.00	0.43	-2.06	-8.47	-10.79	-12.54	-15.47
	USA	%	Production	0.01	-6.99	-14.06	-17.35	-18.73	-25.83	-32.13
		%	**Total**	**-0.03**	**-2.36**	**-5.43**	**-9.99**	**-12.44**	**-16.93**	**-23.40**
	ROW	%	LNG exports	0.00	-0.45	-2.17	-2.76	-4.67	-7.58	-12.19
	Australia + NZ	%	LNG exports	0.00	-0.17	-0.68	-1.96	-3.75	-6.69	-16.17
	LAC	%	LNG exports	0.00	-1.36	-7.87	-12.57	-12.96	-13.56	-18.49
	Africa	%	LNG exports	0.00	-0.38	-2.59	-6.98	-9.90	-13.53	-19.94
	C Asia + East Eur	%	LNG exports	0.00	-5.88	-21.43	-24.30	-20.82	-20.14	-28.12
	Russia	%	LNG exports	0.00	-0.26	-0.26	-3.00	-6.36	-12.70	-23.57
	China	%	LNG exports	0.00	0.00	-100.00	0.00	-20.00	-22.22	-30.77
	India	%	LNG exports	0.00	0.00	0.00	-22.22	-21.05	-27.78	-38.18
	Middle East	%	LNG exports	0.00	0.00	-5.21	-8.34	-8.00	-7.69	-12.65
	EU	%	LNG exports	0.00	2.17	-3.17	-13.79	-19.38	-23.30	-26.97
	Mexico	%	LNG exports	0.00	0.00	0.00	-33.33	-12.50	-17.65	-31.03
	Canada	%	LNG exports	0.00	0.00	-8.68	-6.85	-5.65	-6.12	-10.71

Scenario	Region	Unit	NG Volumes	2020	2025	2030	2035	2040	2045	2050
	USA	%	LNG exports	0.00	0.00	-21.75	-24.89	-25.98	-26.81	-28.88
		%	**Total**	**0.00**	**-0.23**	**-7.57**	**-11.05**	**-13.55**	**-15.88**	**-20.74**
	ROW	%	LNG imports	0.00	-1.68	-8.53	-14.54	-18.20	-22.52	-32.17
	Australia + NZ	%	LNG imports	0.00	0.00	0.00	0.00	0.00	0.00	-19.05
	LAC	%	LNG imports	0.00	2.64	-7.62	-14.73	-21.24	-25.91	-27.41
	Africa	%	LNG imports	0.00	0.86	-6.15	-8.09	-7.95	-5.18	-8.77
	C Asia + East Eur	%	LNG imports	0.00	1.25	-2.51	-10.54	-18.03	-26.61	-33.08
	Russia	%	LNG imports	0.00	0.00	0.00	3.41	1.01	-7.26	-11.81
	China	%	LNG imports	0.00	2.43	-3.15	-3.71	-3.69	-3.02	-5.14
	India	%	LNG imports	-0.25	-2.43	-6.63	-6.03	-4.72	-1.72	-2.24
	Middle East	%	LNG imports	0.00	-10.42	-14.29	-32.04	-36.90	-43.07	-50.32
	EU	%	LNG imports	0.00	-2.37	-20.96	-21.93	-18.96	-17.27	-26.55
	Mexico	%	LNG imports	0.00	0.75	-2.78	-12.82	-25.99	-35.15	-40.09
	Canada	%	LNG imports	0.00	0.00	0.00	-14.29	-48.00	-45.71	-40.54
	USA	%	LNG imports	0.00	-7.69	-21.74	-17.65	-20.00	-37.50	-47.06
		%	**Total**	**-0.05**	**-0.20**	**-7.60**	**-11.05**	**-13.54**	**-15.88**	**-20.75**
	ROW	%	Pipeline exports	0.00	-1.86	-13.62	-15.41	-3.70	-1.13	2.00
	Australia + NZ	%	Pipeline exports	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	LAC	%	Pipeline exports	0.00	-0.55	1.12	-4.97	-7.69	-15.18	-20.00
	Africa	%	Pipeline exports	0.00	-1.77	-9.76	-8.86	2.67	13.84	23.45
	C Asia + East Eur	%	Pipeline exports	0.00	0.00	-20.00	-25.00	0.00	0.00	0.00
	Russia	%	Pipeline exports	0.00	-0.97	-1.36	-6.53	-9.02	-11.27	-25.00
	China	%	Pipeline exports	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	India	%	Pipeline exports	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Middle East	%	Pipeline exports	0.00	0.00	-33.33	0.00	25.00	16.67	50.00
	EU	%	Pipeline exports	0.00	-1.86	-15.44	-16.26	-3.26	-4.17	-8.00
	Mexico	%	Pipeline exports	0.00	0.00	0.00	-40.00	-46.67	-51.43	-51.72
	Canada	%	Pipeline exports	0.00	-2.39	-0.54	-1.68	-8.27	-16.96	-23.10
	USA	%	Pipeline exports	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		%	**Total**	**0.02**	**-1.14**	**-3.46**	**-6.31**	**-6.36**	**-8.19**	**-17.23**
	ROW	%	Pipeline imports	0.00	-1.20	-5.49	-12.50	-12.50	-6.41	-8.60
	Australia + NZ	%	Pipeline imports	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	LAC	%	Pipeline imports	0.00	-0.55	1.12	-4.97	-7.69	-15.18	-20.00
	Africa	%	Pipeline imports	0.00	0.00	5.71	-2.33	5.26	16.55	25.40
	C Asia + East Eur	%	Pipeline imports	0.00	0.00	1.17	-9.62	-21.48	-37.95	-54.77
	Russia	%	Pipeline imports	0.00	0.00	0.00	-1.45	-4.04	-17.58	-27.66
	China	%	Pipeline imports	0.00	1.01	-4.38	-8.75	-8.36	-5.41	-19.77
	India	%	Pipeline imports	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Middle East	%	Pipeline imports	0.00	0.00	0.00	-33.33	-33.33	-45.83	-56.76
	EU	%	Pipeline imports	0.00	-2.47	-8.16	-9.18	-1.10	-0.23	-7.54
	Mexico	%	Pipeline imports	0.00	6.46	8.26	-0.56	-8.90	-12.58	-13.11
	Canada	%	Pipeline imports	0.00	4.22	0.00	-14.97	-17.16	-8.64	-2.04
	USA	%	Pipeline imports	0.00	-5.72	-5.30	2.68	8.76	5.47	-0.56
		%	**Total**	**-0.02**	**-1.18**	**-3.46**	**-6.33**	**-6.36**	**-8.16**	**-17.25**

Table D-12. Primary energy consumption by fuel in 2015 and under all scenarios in 2050 (see Figure 13)

Scenario	Fuel	Units	2015	2050
S1	Biomass	EJ	30.07	95.84
	Biomass CCS	EJ	0	39.58
	Coal	EJ	165.11	153.04
	Coal CCS	EJ	0	8.96
	Gas	EJ	126.84	184.76
	Gas CCS	EJ	0	17.7
	Nuclear	EJ	9.67	20.48
	Oil	EJ	189	179.87
	Oil CCS	EJ	0	5.97
	Other Renewables	EJ	18.54	99.96
	Total	**EJ**	**539.23**	**806.16**

Scenario	Fuel	Units	2015	2050
S2	Biomass	EJ	30.07	95.48
	Biomass CCS	EJ	0	39.77
	Coal	EJ	165.11	152.42
	Coal CCS	EJ	0	8.95
	Gas	EJ	126.84	185.96
	Gas CCS	EJ	0	17.96
	Nuclear	EJ	9.67	20.45
	Oil	EJ	189	179.6
	Oil CCS	EJ	0	5.96
	Other Renewables	EJ	18.54	99.86
	Total	**EJ**	**539.23**	**806.41**
S3	Biomass	EJ	30.07	100.36
	Biomass CCS	EJ	0	44.37
	Coal	EJ	165.11	151.31
	Coal CCS	EJ	0	10.39
	Gas	EJ	126.84	189.54
	Gas CCS	EJ	0	21.24
	Nuclear	EJ	9.67	21.48
	Oil	EJ	189	181.76
	Oil CCS	EJ	0	7.21
	Other Renewables	EJ	18.54	104.99
	Total	**EJ**	**539.23**	**832.65**
S4	Biomass	EJ	30.07	97.32
	Biomass CCS	EJ	0	39.07
	Coal	EJ	165.11	154.51
	Coal CCS	EJ	0	9.13
	Gas	EJ	126.83	182.31
	Gas CCS	EJ	0	17.73
	Nuclear	EJ	9.67	20.73
	Oil	EJ	189	179.54
	Oil CCS	EJ	0	5.93
	Other Renewables	EJ	18.54	99.87
	Total	**EJ**	**539.22**	**806.14**
S5	Biomass	EJ	30.07	90.69
	Biomass CCS	EJ	0	36.23
	Coal	EJ	165.11	151.76
	Coal CCS	EJ	0	7.88
	Gas	EJ	126.84	179.4
	Gas CCS	EJ	0	16.2
	Nuclear	EJ	9.67	18.93
	Oil	EJ	189	178.07
	Oil CCS	EJ	0	4.89
	Other Renewables	EJ	18.54	117.95
	Total	**EJ**	**539.23**	**802**
S6	Biomass	EJ	30.06	35.59
	Biomass CCS	EJ	0	108.7
	Coal	EJ	165.11	44.43
	Coal CCS	EJ	0	35.07
	Gas	EJ	126.83	95.07
	Gas CCS	EJ	0	58.07
	Nuclear	EJ	9.67	34.96
	Oil	EJ	189	144.79
	Oil CCS	EJ	0	16.07
	Other Renewables	EJ	18.54	142.92
	Total	**EJ**	**539.21**	**715.67**
S7	Biomass	EJ	30.06	35.54
	Biomass CCS	EJ	0	108.7
	Coal	EJ	165.11	44.39
	Coal CCS	EJ	0	35.03
	Gas	EJ	126.83	95.24

Scenario	Fuel	Units	2015	2050
	Gas CCS	EJ	0	58.41
	Nuclear	EJ	9.67	34.94
	Oil	EJ	189	144.71
	Oil CCS	EJ	0	16.04
	Other Renewables	EJ	18.54	142.87
	Total	**EJ**	**539.21**	**715.87**

Table D-13. GHG emissions by sector in 2015 and under all scenarios in 2050 (see Figure 13)

Scenario	Sector	2015	2050
S1	CO_2 buildings	2.84	2.54
	CO_2 electricity	12.64	13.04
	CO_2 industry	11.75	11.04
	CO_2 other energy	0.51	1.60
	CO_2 transport	7.89	7.04
	CH_4 energy	5.43	4.80
	CH_4 AgLanduse	3.36	4.97
	N_2O energy	0.96	0.88
	N_2O AgLanduse	2.17	3.28
	F-gases	1.01	1.66
	CO_2 bioenergy	0.00	-1.68
	CO_2 direct air capture	0.00	0.00
	CO_2 LUC	3.04	-1.42
	Total	**51.58**	**47.74**
S2	CO_2 buildings	2.84	2.54
	CO_2 electricity	12.64	13.02
	CO_2 industry	11.75	11.04
	CO_2 other energy	0.51	1.60
	CO_2 transport	7.89	7.03
	CH_4 energy	5.43	4.79
	CH_4 AgLanduse	3.36	4.97
	N_2O energy	0.96	0.88
	N_2O AgLanduse	2.17	3.28
	F-gases	1.01	1.67
	CO_2 bioenergy	0.00	-1.69
	CO_2 direct air capture	0.00	0.00
	CO_2 LUC	3.04	-1.39
	Total	**51.58**	**47.72**
S3	CO_2 buildings	2.84	2.55
	CO_2 electricity	12.64	12.87
	CO_2 industry	11.75	11.27
	CO_2 other energy	0.51	1.63
	CO_2 transport	7.89	7.09
	CH_4 energy	5.43	5.02
	CH_4 AgLanduse	3.36	5.34
	N_2O energy	0.96	0.92
	N_2O AgLanduse	2.17	3.51
	F-gases	1.01	1.76
	CO_2 bioenergy	0.00	-1.88
	CO_2 direct air capture	0.00	0.00
	CO_2 LUC	3.04	0.18
	Total	**51.58**	**50.25**
S4	CO_2 buildings	2.84	2.44
	CO_2 electricity	12.64	13.13
	CO_2 industry	11.75	10.99
	CO_2 other energy	0.51	1.64
	CO_2 transport	7.89	7.05
	CH_4 energy	5.43	4.75
	CH_4 AgLanduse	3.36	4.97
	N_2O energy	0.96	0.88
	N_2O AgLanduse	2.17	3.28

Scenario	Sector	2015	2050
	F-gases	1.01	1.66
	CO_2 bioenergy	0.00	-1.65
	CO_2 direct air capture	0.00	0.00
	CO_2 LUC	3.04	-1.43
	Total	**51.58**	**47.71**
S5	CO_2 buildings	2.84	2.44
	CO_2 electricity	12.64	12.78
	CO_2 industry	11.75	11.08
	CO_2 other energy	0.51	1.58
	CO_2 transport	7.89	7.05
	CH_4 energy	5.43	4.74
	CH_4 AgLanduse	3.36	4.99
	N_2O energy	0.96	0.87
	N_2O AgLanduse	2.17	3.26
	F-gases	1.01	1.68
	CO_2 bioenergy	0.00	-1.51
	CO_2 direct air capture	0.00	0.00
	CO_2 LUC	3.04	-1.50
	Total	**51.58**	**47.47**
S6	CO_2 buildings	2.84	1.12
	CO_2 electricity	12.64	2.16
	CO_2 industry	11.75	6.47
	CO_2 other energy	0.51	0.95
	CO_2 transport	7.89	5.00
	CH_4 energy	5.43	3.25
	CH_4 AgLanduse	3.36	4.69
	N_2O energy	0.96	0.59
	N_2O AgLanduse	2.17	3.03
	F-gases	1.01	1.07
	CO_2 bioenergy	0.00	-6.81
	CO_2 direct air capture	0.00	-0.47
	CO_2 LUC	3.04	-3.92
	Total	**51.58**	**17.13**
S7	CO_2 buildings	2.84	1.12
	CO_2 electricity	12.64	2.16
	CO_2 industry	11.75	6.47
	CO_2 other energy	0.51	0.95
	CO_2 transport	7.89	5.00
	CH_4 energy	5.43	3.24
	CH_4 AgLanduse	3.36	4.69
	N_2O energy	0.96	0.59
	N_2O AgLanduse	2.17	3.03
	F-gases	1.01	1.07
	CO_2 bioenergy	0.00	-6.81
	CO_2 direct air capture	0.00	-0.47
	CO_2 LUC	3.04	-3.92
	Total	**51.58**	**17.12**

Table D-14. U.S. GHG emissions and removals scenarios S6 and S7, by year (see Figure 1)

Commented [IGC211]: NEMS tables start here and need to be renumbered.

CO_2 Emissions and Removals	Units	2020	2025	2030	2035	2040	2045	2050
Net CO_2 Emissions (Carbon Cap in FECM-NEMS)	Gt CO_2e	4.59	4.02	3.26	2.15	1.49	0.93	0.19
Sum of Remaining Emissions & Removals	Gt CO_2e	0.52	0.29	0.19	0.44	0.24	-0.07	-0.18

Table D-15. U.S. primary energy consumption, S1–S5, tabulated by year (see Figure 14)

Scenario	U.S. Primary Energy Consumption	Units	2020	2025	2030	2035	2040	2045	2050
S1	Natural Gas	EJ	33.4	32.1	30.8	30.2	31.2	31.9	32.7
	Coal	EJ	9.6	9.1	4.6	4.5	4.0	3.8	3.5
	Petroleum/Other	EJ	44.4	47.3	46.1	44.8	43.8	44.3	45.2
	Other Renewables	EJ	7.2	11.4	18.7	22.0	23.5	25.2	27.2

Scenario	U.S. Primary Energy Consumption	Units	2020	2025	2030	2035	2040	2045	2050
	Biomass	EJ	3.1	3.2	3.2	3.2	3.2	3.3	3.4
	Total	EJ	**97.7**	**103.1**	**103.4**	**104.7**	**105.8**	**108.4**	**111.9**
S2	Natural Gas	EJ	33.4	32.1	30.8	30.1	30.9	32.0	32.4
	Coal	EJ	9.6	9.2	4.7	4.6	4.2	4.1	3.9
	Petroleum/Other	EJ	44.4	47.3	46.1	44.6	43.9	44.2	45.1
	Other Renewables	EJ	7.2	11.4	18.7	22.1	24.4	26.2	28.6
	Biomass	EJ	3.1	3.2	3.2	3.2	3.2	3.3	3.4
	Total	EJ	**97.7**	**103.1**	**103.4**	**104.6**	**106.7**	**109.8**	**113.3**
S3	Natural Gas	EJ	33.4	32.1	30.6	30.0	30.8	31.9	32.4
	Coal	EJ	9.6	9.2	4.9	4.5	4.2	4.1	4.0
	Petroleum/Other	EJ	44.4	47.3	46.1	44.6	44.0	44.5	45.3
	Other Renewables	EJ	7.2	11.4	18.8	22.3	24.4	26.3	28.5
	Biomass	EJ	3.1	3.2	3.2	3.2	3.2	3.3	3.4
	Total	EJ	**97.7**	**103.1**	**103.5**	**104.8**	**106.8**	**110.0**	**113.5**
S4	Natural Gas	EJ	33.4	32.1	31.4	31.2	31.7	32.5	32.6
	Coal	EJ	9.6	9.2	4.2	4.2	3.7	3.6	3.4
	Petroleum/Other	EJ	44.4	47.3	46.0	44.4	43.4	43.9	44.8
	Other Renewables	EJ	7.2	11.4	18.2	20.6	22.7	24.3	27.2
	Biomass	EJ	3.1	3.2	3.2	3.2	3.2	3.3	3.4
	Total	EJ	**97.7**	**103.2**	**103.0**	**103.6**	**104.8**	**107.6**	**111.3**
S5	Natural Gas	EJ	33.4	32.0	30.0	28.7	29.2	29.3	28.6
	Coal	EJ	9.6	9.2	4.0	3.3	2.8	2.1	1.4
	Petroleum/Other	EJ	44.4	47.4	46.2	44.4	43.2	43.4	46.0
	Other Renewables	EJ	7.2	11.4	20.4	25.4	28.4	31.8	34.2
	Biomass	EJ	3.1	3.2	3.2	3.3	3.4	3.7	4.4
	Total	EJ	**97.7**	**103.2**	**103.8**	**105.2**	**107.0**	**110.2**	**114.6**
S2–S1	Natural Gas	EJ	0.0	-0.1	0.0	-0.1	-0.3	0.1	-0.3
	Coal	EJ	0.0	0.1	0.1	0.1	0.2	0.3	0.4
	Petroleum/Other	EJ	0.0	0.0	0.0	-0.1	0.1	0.0	-0.1
	Other Renewables	EJ	0.0	0.0	0.0	0.1	0.9	1.0	1.4
	Biomass	EJ	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Total	EJ	**0.0**	**0.0**	**0.0**	**-0.1**	**0.8**	**1.4**	**1.4**
S3–S1	Natural Gas	EJ	0.0	0.0	-0.2	-0.2	-0.4	0.0	-0.3
	Coal	EJ	0.0	0.0	0.3	0.0	0.2	0.3	0.5
	Petroleum/Other	EJ	0.0	0.0	0.0	-0.1	0.2	0.2	0.1
	Other Renewables	EJ	0.0	0.0	0.0	0.3	0.9	1.1	1.3
	Biomass	EJ	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Total	EJ	**0.0**	**0.0**	**0.1**	**0.1**	**0.9**	**1.6**	**1.6**
S4–S1	Natural Gas	EJ	0.0	-0.1	0.6	1.0	0.5	0.6	-0.1
	Coal	EJ	0.0	0.1	-0.4	-0.3	-0.3	-0.2	-0.1
	Petroleum/Other	EJ	0.0	0.0	-0.1	-0.4	-0.4	-0.3	-0.4
	Other Renewables	EJ	0.0	0.0	-0.5	-1.4	-0.8	-0.8	0.0
	Biomass	EJ	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Total	EJ	**0.0**	**0.0**	**-0.4**	**-1.1**	**-1.0**	**-0.8**	**-0.6**
S5–S1	Natural Gas	EJ	0.0	-0.1	-0.8	-1.5	-2.1	-2.6	-4.0
	Coal	EJ	0.0	0.1	-0.6	-1.2	-1.2	-1.7	-2.1
	Petroleum/Other	EJ	0.0	0.1	0.2	-0.3	-0.6	-0.9	0.8
	Other Renewables	EJ	0.0	0.0	1.7	3.5	4.9	6.7	7.0
	Biomass	EJ	0.0	-0.1	0.0	0.1	0.1	0.4	1.0
	Total	EJ	**0.0**	**0.0**	**0.4**	**0.5**	**1.1**	**1.8**	**2.7**
S2–S1	Natural Gas	% Difference	0.0	-0.2	0.0	-0.4	-1.1	0.3	-0.8
	Coal	% Difference	0.0	0.7	1.3	1.8	4.7	8.9	12.1
	Petroleum/Other	% Difference	0.0	0.0	0.0	-0.3	0.2	-0.1	-0.2
	Other Renewables	% Difference	0.0	0.0	-0.2	0.5	3.8	4.1	5.0
	Biomass	% Difference	0.0	0.0	0.0	0.0	-0.1	0.0	-0.1
	Total	% Difference	**0.0**	**0.0**	**0.0**	**-0.1**	**0.8**	**1.3**	**1.3**
S3–S1	Natural Gas	% Difference	0.0	0.1	-0.6	-0.1	-0.1	-0.5	-0.1
	Coal	% Difference	0.0	-0.4	4.3	-1.1	0.2	0.3	2.3
	Petroleum/Other	% Difference	0.0	0.0	0.0	0.0	0.2	0.5	0.5
	Other Renewables	% Difference	0.0	0.0	0.4	1.1	0.1	0.3	-0.3
	Biomass	% Difference	0.0	0.0	0.2	0.1	0.1	0.1	0.0
	Total	% Difference	**0.0**	**0.0**	**0.1**	**0.1**	**0.1**	**0.2**	**0.2**

Scenario	U.S. Primary Energy Consumption	Units	2020	2025	2030	2035	2040	2045	2050
S4–S1	Natural Gas	% Difference	0.0	-0.2	1.9	3.4	1.6	1.8	-0.3
	Coal	% Difference	0.0	0.9	-9.1	-7.5	-8.5	-4.8	-2.1
	Petroleum/Other	% Difference	0.0	0.0	-0.1	-0.8	-0.9	-0.8	-0.9
	Other Renewables	% Difference	0.0	0.0	-2.7	-6.2	-3.3	-3.3	-0.1
	Biomass	% Difference	0.0	0.0	0.1	0.2	-0.2	-0.2	-0.5
	Total	% Difference	0.0	0.0	-0.4	-1.0	-1.0	-0.7	-0.5
S5–S1	Natural Gas	% Difference	0.0	-0.4	-2.7	-4.9	-6.6	-8.3	-12.3
	Coal	% Difference	0.0	0.7	-12.0	-25.9	-29.1	-44.9	-59.2
	Petroleum/Other	% Difference	0.0	0.3	0.4	-0.7	-1.4	-2.1	1.8
	Other Renewables	% Difference	0.0	0.4	8.8	15.7	20.8	26.5	25.7
	Biomass	% Difference	0.0	-2.5	0.1	1.6	3.5	12.8	28.9
	Total	% Difference	0.0	0.0	0.4	0.5	1.1	1.7	2.4

Table D-16. U.S. primary energy consumption, S6 and S7, by year (see Figure 15)

Scenario	U.S. Primary Energy Consumption	Units	2020	2025	2030	2035	2040	2045	2050
S6	Natural Gas	EJ	33.4	35.0	29.8	30.8	33.1	37.5	44.8
	Coal	EJ	9.6	1.9	1.8	1.9	1.6	1.6	1.5
	Petroleum/Other	EJ	44.5	47.7	44.5	40.1	37.6	36.6	36.2
	Other Renewables	EJ	7.2	11.7	19.5	26.1	29.6	29.9	30.9
	Biomass	EJ	3.2	3.7	4.6	5.9	6.7	7.5	8.1
	Total	EJ	97.8	99.9	100.3	104.8	108.7	113.0	121.5
S7	Natural Gas	EJ	33.4	34.9	30.0	30.3	32.8	37.1	44.4
	Coal	EJ	9.6	1.9	2.1	1.9	1.9	1.9	1.6
	Petroleum/Other	EJ	44.5	47.7	44.5	40.0	37.1	36.3	35.8
	Other Renewables	EJ	7.2	11.7	19.0	25.9	29.4	29.5	30.5
	Biomass	EJ	3.2	3.7	4.6	5.7	6.7	7.6	8.2
	Total	EJ	97.8	100.0	100.2	103.8	107.9	112.5	120.6
S7–S6	Natural Gas	EJ	0.0	0.0	0.1	-0.5	-0.4	-0.4	-0.4
	Coal	EJ	0.0	0.0	0.2	0.1	0.3	0.3	0.2
	Petroleum/Other	EJ	0.0	0.0	0.0	-0.2	-0.5	-0.2	-0.4
	Other Renewables	EJ	0.0	0.0	-0.6	-0.1	-0.2	-0.3	-0.4
	Biomass	EJ	0.0	0.0	0.1	-0.2	0.0	0.1	0.1
	Total	EJ	0.0	0.0	-0.1	-1.0	-0.8	-0.5	-0.9
	Natural Gas	% Difference	0.0	-0.1	0.5	-1.7	-1.1	-1.0	-0.9
	Coal	% Difference	0.0	1.9	11.9	3.5	16.3	21.0	10.7
	Petroleum/Other	% Difference	0.0	0.0	0.0	-0.5	-1.2	-0.7	-1.1
	Other Renewables	% Difference	0.0	0.0	-2.8	-0.6	-0.7	-1.1	-1.2
	Biomass	% Difference	0.0	0.8	1.3	-3.6	-0.6	1.5	1.5
	Total	% Difference	0.0	0.0	-0.1	-1.0	-0.7	-0.4	-0.7

Table D-17. Total U.S. natural gas production, consumption, and export volumes, S1–S5, by year (see Figure 16

Scenario	Total U.S. Natural Gas Volumes	Units	2020	2025	2030	2035	2040	2045	2050
S1	NG Production	Tcf	33.5	35.8	37.0	39.5	40.9	41.4	42.0
S2	NG Production	Tcf	33.5	36.2	37.5	39.4	43.7	47.5	49.0
S3	NG Production	Tcf	33.5	36.2	37.3	39.5	43.9	47.7	49.5
S4	NG Production	Tcf	33.5	36.2	35.8	36.4	37.6	39.8	40.7
S5	NG Production	Tcf	33.5	36.1	36.8	38.2	42.3	45.0	45.7
S1	NG Consumption	Tcf	30.5	29.4	28.2	27.6	28.5	29.2	29.8
S2	NG Consumption	Tcf	30.5	29.3	28.2	27.5	28.2	29.2	29.6
S3	NG Consumption	Tcf	30.5	29.3	28.0	27.4	28.2	29.1	29.6
S4	NG Consumption	Tcf	30.5	29.3	28.7	28.5	29.0	29.7	29.8
S5	NG Consumption	Tcf	30.5	29.2	27.4	26.2	26.6	26.7	26.2
S1	LNG Exports	Tcf	2.4	4.9	6.9	9.5	10.0	10.0	10.0
S2	LNG Exports	Tcf	2.4	4.9	6.9	9.1	12.8	15.6	17.2
S3	LNG Exports	Tcf	2.4	4.9	6.9	9.2	13.0	16.0	17.8
S4	LNG Exports	Tcf	2.4	4.9	4.4	4.8	5.6	7.2	8.4
S5	LNG Exports	Tcf	2.4	4.9	6.9	9.1	12.8	15.6	17.2
S2–S1	NG Production	Tcf	0.0	0.4	0.5	0.0	2.8	6.1	7.1

Scenario	Total U.S. Natural Gas Volumes	Units	2020	2025	2030	2035	2040	2045	2050
S3–S1	NG Production	Tcf	0.0	0.4	0.3	0.1	3.1	6.3	7.6
S4–S1	NG Production	Tcf	0.0	0.4	-1.3	-3.0	-3.3	-1.6	-1.3
S5–S1	NG Production	Tcf	0.0	0.3	-0.2	-1.2	1.4	3.6	3.8
S2–S1	NG Consumption	Tcf	0.0	-0.1	0.0	-0.1	-0.3	0.1	-0.2
S3–S1	NG Consumption	Tcf	0.0	0.0	-0.2	-0.2	-0.4	0.0	-0.3
S4–S1	NG Consumption	Tcf	0.0	-0.1	0.6	0.9	0.4	0.5	-0.1
S5–S1	NG Consumption	Tcf	0.0	-0.1	-0.8	-1.3	-1.9	-2.4	-3.7
S2–S1	LNG Exports	Tcf	0.0	0.0	0.0	-0.4	2.8	5.7	7.3
S3–S1	LNG Exports	Tcf	0.0	0.0	0.0	-0.3	3.0	6.0	7.8
S4–S1	LNG Exports	Tcf	0.0	0.0	-2.4	-4.6	-4.4	-2.8	-1.6
S5–S1	LNG Exports	Tcf	0.0	0.0	0.0	-0.4	2.8	5.6	7.2
S2–S1	NG Production	% Difference	0.0	1.1	1.3	-0.1	7.0	14.8	16.9
S3–S1	NG Production	% Difference	0.0	1.1	0.9	0.1	7.5	15.3	18.1
S4–S1	NG Production	% Difference	0.0	1.1	-3.4	-7.7	-8.0	-3.8	-3.1
S5–S1	NG Production	% Difference	0.0	0.9	-0.6	-3.0	3.3	8.7	9.0
S2–S1	NG Consumption	% Difference	0.0	-0.2	0.0	-0.4	-1.1	0.3	-0.8
S3–S1	NG Consumption	% Difference	0.0	-0.1	-0.7	-0.6	-1.2	-0.2	-0.9
S4–S1	NG Consumption	% Difference	0.0	-0.2	2.0	3.4	1.6	1.8	-0.3
S5–S1	NG Consumption	% Difference	0.0	-0.4	-2.7	-4.9	-6.6	-8.3	-12.3
S2–S1	LNG Exports	% Difference	0.0	0.0	0.0	-4.2	27.6	56.7	72.7
S3–S1	LNG Exports	% Difference	0.0	0.0	0.0	-2.9	29.9	60.6	78.3
S4–S1	LNG Exports	% Difference	0.0	0.0	-35.6	-48.9	-44.3	-27.6	-15.7
S5–S1	LNG Exports	% Difference	0.0	0.0	0.0	-4.0	27.7	56.1	72.5

*1 Tcf in a non-leap year is equivalent to 2.74 Bcf/d

Table D-18. Total U.S. natural gas production, consumption, and export volumes, S6 and S7, by year (see Figure 17)

Scenario	Total U.S. Natural Gas Volumes	Units	2020	2025	2030	2035	2040	2045	2050
S6	NG Production	Tcf	34.1	38.5	35.1	37.6	42.6	47.4	54.7
S7	NG Production	Tcf	34.1	38.5	35.3	37.1	42.3	48.6	56.5
S6	NG Consumption	Tcf	30.5	32.0	27.4	28.4	30.8	35.0	41.9
S7	NG Consumption	Tcf	30.5	31.9	27.5	27.9	30.5	34.7	41.5
S6	LNG Exports	Tcf	2.4	4.9	5.4	6.8	9.4	10.0	10.0
S7	LNG Exports	Tcf	2.4	4.9	5.4	6.8	9.4	11.4	12.3
S7–S6	NG Production	Tcf	0.0	0.0	0.1	-0.4	-0.3	1.2	1.8
	NG Consumption	Tcf	0.0	0.0	0.1	-0.5	-0.3	-0.3	-0.3
	LNG Exports	Tcf	0.0	0.0	0.0	0.0	0.0	1.5	2.3
	NG Production	% Difference	0.0	-0.1	0.4	-1.1	-0.8	2.4	3.4
	NG Consumption	% Difference	0.0	-0.1	0.5	-1.7	-1.1	-0.9	-0.8
	LNG Exports	% Difference	0.0	0.0	0.0	0.0	0.0	14.8	22.9

*1 Tcf in a non-leap year is equivalent to 2.74 Bcf/d

Table D-19. U.S. natural gas Henry Hub price, S1–S7, tabulated by year (see Figure 18)

Scenario	Units	2020	2025	2030	2035	2040	2045	2050
S1	$2022/Mcf	2.31	3.63	3.04	3.81	4.08	4.05	3.88
S2	$2022/Mcf	2.31	3.70	3.09	3.77	4.50	4.61	5.09
S3	$2022/Mcf	2.31	3.69	3.06	3.78	4.54	4.65	5.15
S4	$2022/Mcf	2.31	3.68	2.63	3.03	3.52	3.73	4.12
S5	$2022/Mcf	2.31	3.68	3.00	3.65	4.38	4.41	4.67
S2–S1	$2022/Mcf	0.00	0.07	0.05	-0.04	0.42	0.56	1.22
S3–S1	$2022/Mcf	0.00	0.07	0.02	-0.03	0.46	0.60	1.27
S4–S1	$2022/Mcf	0.00	0.06	-0.41	-0.78	-0.56	-0.32	0.24
S5–S1	$2022/Mcf	0.00	0.06	-0.04	-0.16	0.30	0.37	0.80
S2–S1	% Difference	0.0	2.0	1.7	-1.1	10.4	13.9	31.4
S3–S1	% Difference	0.0	1.9	0.5	-0.8	11.4	14.8	32.8
S4–S1	% Difference	0.0	1.6	-13.5	-20.6	-13.6	-7.9	6.3
S5–S1	% Difference	0.0	1.6	-1.2	-4.2	7.3	9.0	20.5
S6	$2022/Mcf	2.35	3.80	3.36	4.42	4.67	5.46	6.34
S7	$2022/Mcf	2.35	3.80	3.42	4.34	4.70	5.40	6.20

Scenario	Units	2020	2025	2030	2035	2040	2045	2050
S7–S6	$2022/Mcf	0.00	0.00	0.06	-0.08	0.03	-0.06	-0.14
	% Difference	0.0	0.0	1.8	-1.8	0.6	-1.1	-2.2

Table D-20. U.S. real GDP, S1–S5, by year (see Figure 19)

Scenario	Units	2020	2025	2030	2035	2040	2045	2050
S1	$2022, Trillion	23.3	25.9	28.4	31.1	34.5	38.2	42.4
S2	$2022, Trillion	23.3	25.9	28.4	31.1	34.5	38.3	42.3
S3	$2022, Trillion	23.3	25.9	28.4	31.1	34.5	38.3	42.3
S4	$2022, Trillion	23.3	25.9	28.4	31.1	34.4	38.2	42.3
S5	$2022, Trillion	23.3	25.9	28.4	31.1	34.4	38.3	42.3
S2–S1	$2022, Trillion	0.0	0.0	0.0	0.0	0.0	0.0	-0.1
S3–S1	$2022, Trillion	0.0	0.0	0.0	0.0	0.0	0.0	-0.1
S4–S1	$2022, Trillion	0.0	0.0	0.0	0.0	0.0	0.0	-0.1
S5–S1	$2022, Trillion	0.0	0.0	0.0	0.0	0.0	0.0	-0.1
S2–S1	% Difference	0.0	0.0	0.0	0.0	0.0	0.1	-0.3
S3–S1	% Difference	0.0	0.0	0.0	0.0	0.0	0.1	-0.2
S4–S1	% Difference	0.0	0.0	0.0	0.0	-0.1	0.0	-0.2
S5–S1	% Difference	0.0	-0.1	0.1	0.0	0.0	0.1	-0.2

Table D-21. U.S. residential natural gas prices, S1–S5, by year (see Figure 20)

Scenario	Units	2020	2025	2030	2035	2040	2045	2050
S1	$2022/Mcf	12.09	12.58	11.37	11.96	12.33	12.75	12.74
S2	$2022/Mcf	12.09	12.65	11.41	11.93	12.56	12.69	13.28
S3	$2022/Mcf	12.09	12.65	11.37	11.91	12.55	12.68	13.28
S4	$2022/Mcf	12.09	12.65	11.12	11.53	12.04	12.64	12.92
S5	$2022/Mcf	12.09	12.58	11.33	11.83	12.41	12.48	13.00
S2–S1	$2022/Mcf	0.00	0.06	0.04	-0.03	0.23	-0.06	0.54
S3–S1	$2022/Mcf	0.00	0.06	-0.01	-0.05	0.23	-0.07	0.54
S4–S1	$2022/Mcf	0.00	0.06	-0.25	-0.43	-0.29	-0.11	0.18
S5–S1	$2022/Mcf	0.00	0.00	-0.05	-0.14	0.08	-0.28	0.26
S2–S1	% Difference	0.0	0.5	0.3	-0.3	1.9	-0.5	4.2
S3–S1	% Difference	0.0	0.5	-0.1	-0.4	1.8	-0.6	4.2
S4–S1	% Difference	0.0	0.5	-2.2	-3.6	-2.3	-0.9	1.4
S5–S1	% Difference	0.0	0.0	-0.4	-1.1	0.7	-2.2	2.0

Table D-22. U.S. value of industrial shipments and real consumption, S1–S5, by year (see Figure 21)

Scenario	Total U.S. Value	Units	2020	2025	2030	2035	2040	2045	2050
S1	Industrial Shipments	$2022, Trillion	11.0	12.0	12.8	13.5	14.3	15.2	16.2
S2	Industrial Shipments	$2022, Trillion	11.0	12.0	12.8	13.5	14.4	15.3	16.2
S3	Industrial Shipments	$2022, Trillion	11.0	12.0	12.8	13.5	14.4	15.3	16.2
S4	Industrial Shipments	$2022, Trillion	11.0	12.0	12.8	13.4	14.3	15.2	16.1
S5	Industrial Shipments	$2022, Trillion	11.0	12.0	12.8	13.5	14.3	15.3	16.2
S1	Real Consumption	$2022, Trillion	16.0	18.5	20.8	23.4	26.4	29.8	33.5
S2	Real Consumption	$2022, Trillion	16.0	18.4	20.8	23.4	26.4	29.8	33.5
S3	Real Consumption	$2022, Trillion	16.0	18.4	20.8	23.4	26.4	29.8	33.5
S4	Real Consumption	$2022, Trillion	16.0	18.5	20.8	23.5	26.4	29.8	33.5
S5	Real Consumption	$2022, Trillion	16.0	18.4	20.8	23.4	26.4	29.8	33.5
S2–S1	Industrial Shipments	$2022, Trillion	0.0	0.0	0.0	0.0	0.0	0.1	0.0
S3–S1	Industrial Shipments	$2022, Trillion	0.0	0.0	0.0	0.0	0.0	0.1	0.0
S4–S1	Industrial Shipments	$2022, Trillion	0.0	0.0	0.0	0.0	-0.1	0.0	-0.1
S5–S1	Industrial Shipments	$2022, Trillion	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S2–S1	Real Consumption	$2022, Trillion	0.0	0.0	0.0	0.0	0.0	0.0	-0.1
S3–S1	Real Consumption	$2022, Trillion	0.0	0.0	0.0	0.0	0.0	0.0	-0.1
S4–S1	Real Consumption	$2022, Trillion	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S5–S1	Real Consumption	$2022, Trillion	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S2–S1	Industrial Shipments	% Difference	0.0	0.0	0.0	-0.1	0.3	0.7	0.1
S3–S1	Industrial Shipments	% Difference	0.0	0.0	0.0	-0.1	0.3	0.7	0.2
S4–S1	Industrial Shipments	% Difference	0.0	0.0	-0.1	-0.2	-0.4	-0.2	-0.4

Scenario	Total U.S. Value	Units	2020	2025	2030	2035	2040	2045	2050
S5–S1	Industrial Shipments	% Difference	0.0	-0.1	0.1	-0.2	0.0	0.3	0.0
S2–S1	Real Consumption	% Difference	0.0	0.0	0.0	0.0	0.0	0.1	-0.2
S3–S1	Real Consumption	% Difference	0.0	0.0	0.0	0.0	0.0	0.1	-0.2
S4–S1	Real Consumption	% Difference	0.0	0.0	0.0	0.1	-0.1	0.0	-0.1
S5–S1	Real Consumption	% Difference	0.0	-0.1	0.1	0.0	0.0	0.1	-0.1

Table D-23. U.S. LNG export revenues, S1–S5, by year (see Figure 22)

Scenario	Units	2020	2025	2030	2035	2040	2045	2050
S1	$2022, Billion	37.1	25.6	40.3	60.8	69.2	69.8	69.9
S2	$2022, Billion	37.1	25.6	40.3	58.8	84.9	106.3	118.3
S3	$2022, Billion	37.1	25.6	40.5	59.7	86.3	108.4	121.5
S4	$2022, Billion	37.1	26.0	30.6	36.4	40.8	52.2	60.1
S5	$2022, Billion	37.0	25.5	40.2	58.7	84.5	104.5	115.7
S2–S1	$2022, Billion	0.0	0.0	0.0	-2.0	15.7	36.6	48.4
S3–S1	$2022, Billion	-0.1	0.0	0.2	-1.1	17.1	38.6	51.6
S4–S1	$2022, Billion	0.0	0.4	-9.7	-24.3	-28.4	-17.5	-9.8
S5–S1	$2022, Billion	-0.1	-0.1	-0.2	-2.1	15.3	34.7	45.8
S2–S1	% Difference	0.0	0.0	0.0	-3.3	22.6	52.4	69.3
S3–S1	% Difference	-0.2	0.0	0.5	-1.7	24.7	55.4	73.8
S4–S1	% Difference	0.0	1.5	-24.0	-40.0	-41.1	-25.1	-14.0
S5–S1	% Difference	-0.3	-0.4	-0.4	-3.4	22.0	49.8	65.5

Table D-24. Total U.S. CO_2 emissions from fossil fuel combustion, S1–S5, by year (see Figure 23)

Scenario	Units	2020	2025	2030	2035	2040	2045	2050
S1	Gt CO_2	4.58	4.55	4.00	3.89	3.87	3.89	3.94
S2	Gt CO_2	4.58	4.56	4.01	3.89	3.87	3.94	3.97
S3	Gt CO_2	4.58	4.55	4.02	3.89	3.88	3.94	3.98
S4	Gt CO_2	4.58	4.56	3.99	3.90	3.86	3.90	3.93
S5	Gt CO_2	4.58	4.56	3.91	3.71	3.67	3.62	3.57
S2–S1	Gt CO_2	0.00	0.00	0.00	0.00	0.00	0.04	0.03
S3–S1	Gt CO_2	0.00	0.00	0.01	0.00	0.01	0.04	0.04
S4–S1	Gt CO_2	0.00	0.00	-0.02	0.01	-0.01	0.01	-0.02
S5–S1	Gt CO_2	0.00	0.01	-0.09	-0.18	-0.21	-0.28	-0.38
S2–S1	% Difference	0.0	0.0	0.1	0.0	0.0	1.1	0.7
S3–S1	% Difference	0.0	0.0	0.3	-0.1	0.1	1.1	0.9
S4–S1	% Difference	0.0	0.1	-0.4	0.3	-0.3	0.3	-0.4
S5–S1	% Difference	0.0	0.1	-2.3	-4.6	-5.3	-7.1	-9.6

Table D-25. U.S. CO_2 emissions, fossil fuel combustion and removals, S6 and S7, by year (see Figure 24)

Scenario	CO_2 Emissions and Removals	Units	2020	2025	2030	2035	2040	2045	2050
S6	Emissions	Gt CO_2	4.58	4.03	3.32	2.80	2.55	2.43	2.37
S7	Emissions	Gt CO_2	4.58	4.02	3.33	2.80	2.53	2.41	2.35
S6	Removals	Gt CO_2	0.00	0.00	0.05	0.65	1.06	1.49	2.16
S7	Removals	Gt CO_2	0.00	0.00	0.07	0.60	1.04	1.48	2.13
S7–S6	Emissions	Gt CO_2	0.00	-0.01	0.01	-0.01	-0.02	-0.02	-0.02
	Removals	Gt CO_2	0.00	0.00	0.02	-0.05	-0.01	-0.01	-0.03
	Emissions	% Difference	0.0	-0.1	0.2	-0.3	-0.8	-0.7	-1.0
	Removals	% Difference	0.0	-1.0	52.1	-8.3	-1.3	-0.7	-1.2

Table D-26. U.S. regional onshore natural gas production, S1–S5, by year (see Figure B-1)

Scenario	Natural Gas Volumes	Units	2020	2025	2030	2035	2040	2045	2050
S1	East	Tcf	12.0	12.3	13.1	14.3	14.6	15.1	15.5
	Gulf Coast	Tcf	7.0	9.5	9.2	10.5	11.2	11.0	11.0
	Southwest	Tcf	5.1	5.8	6.0	6.4	6.8	7.1	7.4
	Other Onshore	Tcf	8.2	6.9	6.9	6.5	6.6	6.4	6.3
	Total	Tcf	32.4	34.5	35.3	37.7	39.3	39.6	40.1
S2	East	Tcf	12.0	12.5	13.3	14.4	15.2	15.7	16.1

Scenario	Natural Gas Volumes	Units	2020	2025	2030	2035	2040	2045	2050
	Gulf Coast	Tcf	7.0	9.6	9.4	10.3	12.6	14.3	15.1
	Southwest	Tcf	5.1	5.8	6.1	6.4	7.3	8.3	9.1
	Other Onshore	Tcf	8.2	7.0	7.0	6.6	7.0	7.4	7.5
	Total	**Tcf**	**32.4**	**34.9**	**35.7**	**37.7**	**42.1**	**45.7**	**47.8**
	East	Tcf	12.0	12.5	13.2	14.4	15.1	15.7	16.1
	Gulf Coast	Tcf	7.0	9.6	9.4	10.4	12.8	14.5	15.4
S3	Southwest	Tcf	5.1	5.8	6.1	6.4	7.3	8.3	9.2
	Other Onshore	Tcf	8.2	7.0	7.0	6.6	7.1	7.4	7.6
	Total	**Tcf**	**32.4**	**34.9**	**35.6**	**37.8**	**42.3**	**45.9**	**48.3**
	East	Tcf	12.0	12.5	12.7	13.6	14.1	14.7	15.4
	Gulf Coast	Tcf	7.0	9.7	8.8	8.9	9.5	10.3	10.6
S4	Southwest	Tcf	5.1	5.8	5.8	5.9	6.1	6.8	7.2
	Other Onshore	Tcf	8.2	7.0	6.8	6.3	6.3	6.3	6.1
	Total	**Tcf**	**32.4**	**34.9**	**34.0**	**34.7**	**36.0**	**38.1**	**39.3**
	East	Tcf	12.0	12.4	12.8	13.6	14.3	14.4	14.2
	Gulf Coast	Tcf	7.0	9.6	9.3	10.1	12.3	13.6	14.4
S5	Southwest	Tcf	5.1	5.8	6.0	6.4	7.2	8.1	8.7
	Other Onshore	Tcf	8.2	7.0	6.9	6.5	6.9	7.1	7.2
	Total	**Tcf**	**32.4**	**34.8**	**35.1**	**36.5**	**40.7**	**43.2**	**44.4**
	East	Tcf	0.0	0.2	0.2	0.0	0.5	0.6	0.6
	Gulf Coast	Tcf	0.0	0.1	0.2	-0.2	1.3	3.3	4.2
S2–S1	Southwest	Tcf	0.0	0.0	0.0	0.0	0.5	1.2	1.7
	Other Onshore	Tcf	0.0	0.1	0.1	0.1	0.4	1.0	1.2
	Total	**Tcf**	**0.0**	**0.4**	**0.5**	**-0.1**	**2.8**	**6.0**	**7.7**
	East	Tcf	0.0	0.2	0.1	0.0	0.5	0.5	0.7
	Gulf Coast	Tcf	0.0	0.1	0.2	-0.1	1.5	3.5	4.4
S3–S1	Southwest	Tcf	0.0	0.0	0.0	0.0	0.6	1.2	1.7
	Other Onshore	Tcf	0.0	0.1	0.1	0.1	0.5	1.0	1.3
	Total	**Tcf**	**0.0**	**0.4**	**0.3**	**0.1**	**3.1**	**6.3**	**8.2**
	East	Tcf	0.0	0.2	-0.4	-0.7	-0.6	-0.4	0.0
	Gulf Coast	Tcf	0.0	0.2	-0.4	-1.5	-1.7	-0.6	-0.3
S4–S1	Southwest	Tcf	0.0	0.0	-0.3	-0.6	-0.6	-0.3	-0.2
	Other Onshore	Tcf	0.0	0.0	-0.2	-0.2	-0.3	-0.2	-0.2
	Total	**Tcf**	**0.0**	**0.4**	**-1.3**	**-3.0**	**-3.2**	**-1.5**	**-0.7**
	East	Tcf	0.0	0.1	-0.3	-0.8	-0.4	-0.7	-1.3
	Gulf Coast	Tcf	0.0	0.1	0.1	-0.3	1.1	2.6	3.5
S5–S1	Southwest	Tcf	0.0	0.0	0.0	-0.1	0.4	1.0	1.3
	Other Onshore	Tcf	0.0	0.1	0.0	0.0	0.3	0.7	0.9
	Total	**Tcf**	**0.0**	**0.3**	**-0.2**	**-1.2**	**1.4**	**3.6**	**4.4**
	East	% Difference	0.0	1.8	1.5	0.2	3.7	3.9	4.0
	Gulf Coast	% Difference	0.0	1.0	1.8	-1.6	11.8	30.1	38.1
S2–S1	Southwest	% Difference	0.0	0.2	0.4	-0.1	7.9	16.6	22.3
	Other Onshore	% Difference	0.0	0.8	1.2	1.4	6.7	15.3	19.8
	Total	**% Difference**	**0.0**	**1.1**	**1.3**	**-0.1**	**7.2**	**15.2**	**19.2**
	East	% Difference	0.0	1.7	0.4	0.2	3.4	3.5	4.3
	Gulf Coast	% Difference	0.0	1.4	2.0	-0.7	13.3	32.0	40.5
S3–S1	Southwest	% Difference	0.0	0.2	0.2	-0.2	8.3	17.1	23.6
	Other Onshore	% Difference	0.0	0.8	1.1	1.7	7.6	15.8	21.1
	Total	**% Difference**	**0.0**	**1.2**	**0.9**	**0.1**	**7.8**	**15.8**	**20.4**
	East	% Difference	0.0	1.4	-3.1	-5.1	-3.8	-2.8	-0.1
	Gulf Coast	% Difference	0.0	2.4	-4.6	-14.6	-15.5	-5.9	-3.0
S4–S1	Southwest	% Difference	0.0	0.0	-4.3	-8.7	-9.3	-4.0	-3.0
	Other Onshore	% Difference	0.0	0.2	-2.3	-2.7	-4.7	-2.4	-2.7
	Total	**% Difference**	**0.0**	**1.2**	**-3.6**	**-8.0**	**-8.3**	**-3.8**	**-1.8**
	East	% Difference	0.0	0.7	-2.1	-5.5	-2.6	-4.8	-8.3
	Gulf Coast	% Difference	0.0	1.4	1.1	-3.3	9.5	23.9	31.5
S5–S1	Southwest	% Difference	0.0	0.3	-0.2	-1.2	6.1	14.2	16.9
	Other Onshore	% Difference	0.0	1.1	0.0	0.3	4.5	10.6	14.9
	Total	**% Difference**	**0.0**	**0.9**	**-0.5**	**-3.2**	**3.5**	**9.0**	**10.9**

*1 Tcf in a non-leap year is equivalent to 2.74 Bcf/d

Table D-27. U.S. regional onshore natural gas production, S6 and S7, by year (see Figure B-2)

Scenario	Natural Gas Volumes	Units	2020	2025	2030	2035	2040	2045	2050
S6	East	Tcf	12.5	14.2	12.7	13.7	15.0	17.4	20.6
	Gulf Coast	Tcf	6.8	10.1	8.5	9.2	11.6	12.2	13.9
	Southwest	Tcf	5.5	5.4	5.4	5.7	6.3	7.1	8.0
	Other Onshore	Tcf	8.1	7.5	6.9	6.9	7.5	8.6	9.8
	Total	Tcf	33.0	37.3	33.5	35.5	40.3	45.2	52.3
S7	East	Tcf	12.5	14.2	12.7	13.6	15.0	17.3	20.4
	Gulf Coast	Tcf	6.8	10.2	8.6	9.0	11.3	13.1	15.4
	Southwest	Tcf	5.5	5.4	5.4	5.6	6.3	7.2	8.6
	Other Onshore	Tcf	8.1	7.5	6.9	6.9	7.5	8.7	9.7
	Total	Tcf	33.0	37.3	33.6	35.1	40.0	46.3	54.1
S7–S6	East	Tcf	0.0	0.0	0.0	-0.1	0.1	-0.1	-0.2
	Gulf Coast	Tcf	0.0	0.0	0.1	-0.2	-0.3	1.0	1.5
	Southwest	Tcf	0.0	0.0	0.0	0.0	0.0	0.2	0.6
	Other Onshore	Tcf	0.0	0.0	0.0	-0.1	0.0	0.1	-0.1
	Total	Tcf	0.0	0.0	0.1	-0.4	-0.3	1.1	1.8
	East	% Difference	0.0	-0.3	0.3	-0.8	0.4	-0.4	-0.9
	Gulf Coast	% Difference	0.0	0.1	1.0	-2.0	-2.7	8.0	10.8
	Southwest	% Difference	0.0	0.0	0.1	-0.5	-0.2	2.2	7.6
	Other Onshore	% Difference	0.0	0.0	-0.1	-1.1	-0.7	0.8	-1.2
	Total	% Difference	0.0	-0.1	0.4	-1.1	-0.7	2.5	3.4

*1 Tcf in a non-leap year is equivalent to 2.74 Bcf/d

Table D-28. Sectoral U.S. natural gas consumption, S1–S5, by year (see Figure B-3)

Scenario	Natural Gas Volumes	Units	2020	2025	2030	2035	2040	2045	2050
S1	Electricity	Tcf	11.6	9.7	7.7	6.6	7.2	7.5	7.6
S2	Electricity	Tcf	11.6	9.6	7.7	6.6	6.6	6.8	6.7
S3	Electricity	Tcf	11.6	9.6	7.5	6.5	6.5	6.6	6.6
S4	Electricity	Tcf	11.6	9.6	8.3	7.9	8.0	8.2	7.8
S5	Electricity	Tcf	11.6	9.5	6.9	5.4	5.1	4.4	3.4
S1	Industry	Tcf	9.9	10.3	10.9	11.1	11.5	11.8	12.3
S2	Industry	Tcf	9.9	10.3	10.9	11.1	11.6	12.1	12.3
S3	Industry	Tcf	9.9	10.3	10.9	11.1	11.6	12.1	12.4
S4	Industry	Tcf	9.9	10.3	10.9	11.1	11.5	11.8	12.2
S5	Industry	Tcf	9.9	10.3	10.9	11.1	11.5	12.0	12.2
S1	Residential	Tcf	4.7	4.8	4.8	4.8	4.7	4.7	4.7
S2	Residential	Tcf	4.7	4.8	4.8	4.8	4.7	4.7	4.7
S3	Residential	Tcf	4.7	4.8	4.8	4.8	4.7	4.7	4.7
S4	Residential	Tcf	4.7	4.8	4.8	4.8	4.7	4.7	4.7
S5	Residential	Tcf	4.7	4.8	4.8	4.8	4.7	4.7	4.7
S1	Commercial	Tcf	3.2	3.4	3.5	3.5	3.5	3.5	3.4
S2	Commercial	Tcf	3.2	3.4	3.5	3.5	3.5	3.5	3.4
S3	Commercial	Tcf	3.2	3.4	3.5	3.5	3.5	3.5	3.4
S4	Commercial	Tcf	3.2	3.4	3.5	3.6	3.5	3.5	3.4
S5	Commercial	Tcf	3.2	3.4	3.5	3.5	3.5	3.5	3.4
S1	Transportation	Tcf	1.1	1.2	1.3	1.5	1.6	1.7	1.8
S2	Transportation	Tcf	1.1	1.2	1.3	1.5	1.9	2.2	2.5
S3	Transportation	Tcf	1.1	1.2	1.3	1.5	1.9	2.2	2.5
S4	Transportation	Tcf	1.1	1.2	1.1	1.1	1.2	1.4	1.6
S5	Transportation	Tcf	1.1	1.2	1.3	1.5	1.8	2.2	2.4
S1	Total	Tcf	30.5	29.4	28.2	27.6	28.5	29.2	29.8
S2	Total	Tcf	30.5	29.3	28.2	27.5	28.2	29.2	29.6
S3	Total	Tcf	30.5	29.3	28.0	27.4	28.2	29.1	29.6
S4	Total	Tcf	30.5	29.3	28.7	28.5	29.0	29.7	29.8
S5	Total	Tcf	30.5	29.2	27.4	26.2	26.6	26.7	26.2
S2–S1	Electricity	Tcf	0.0	-0.1	0.0	-0.1	-0.6	-0.7	-0.9
S3–S1	Electricity	Tcf	0.0	0.0	-0.2	-0.1	-0.6	-0.9	-1.0
S4–S1	Electricity	Tcf	0.0	-0.1	0.7	1.2	0.8	0.8	0.2
S5–S1	Electricity	Tcf	0.0	-0.2	-0.8	-1.3	-2.1	-3.0	-4.2
S2–S1	Industry	Tcf	0.0	0.0	0.0	0.0	0.0	0.3	0.0

Scenario	Natural Gas Volumes	Units	2020	2025	2030	2035	2040	2045	2050
S3–S1	Industry	Tcf	0.0	0.0	0.0	0.0	0.0	0.3	0.0
S4–S1	Industry	Tcf	0.0	0.0	0.0	0.0	-0.1	0.0	-0.1
S5–S1	Industry	Tcf	0.0	0.1	0.0	0.0	0.0	0.1	-0.1
S2–S1	Residential	Tcf	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S3–S1	Residential	Tcf	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S4–S1	Residential	Tcf	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S5–S1	Residential	Tcf	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S2–S1	Commercial	Tcf	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S3–S1	Commercial	Tcf	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S4–S1	Commercial	Tcf	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S5–S1	Commercial	Tcf	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S2–S1	Transportation	Tcf	0.0	0.0	0.0	0.0	0.3	0.5	0.7
S3–S1	Transportation	Tcf	0.0	0.0	0.0	0.0	0.3	0.6	0.7
S4–S1	Transportation	Tcf	0.0	0.0	-0.2	-0.4	-0.4	-0.2	-0.1
S5–S1	Transportation	Tcf	0.0	0.0	0.0	0.0	0.2	0.5	0.7
S2–S1	**Total**	**Tcf**	**0.0**	**-0.1**	**0.0**	**-0.1**	**-0.3**	**0.1**	**-0.2**
S3–S1	**Total**	**Tcf**	**0.0**	**0.0**	**-0.2**	**-0.2**	**-0.4**	**0.0**	**-0.3**
S4–S1	**Total**	**Tcf**	**0.0**	**-0.1**	**0.6**	**0.9**	**0.4**	**0.5**	**-0.1**
S5–S1	**Total**	**Tcf**	**0.0**	**-0.1**	**-0.8**	**-1.3**	**-1.9**	**-2.4**	**-3.7**
S2–S1	Electricity	% Difference	0.0	-0.5	-0.2	-1.3	-8.3	-9.1	-11.5
S3–S1	Electricity	% Difference	0.0	-0.3	-2.5	-2.1	-9.0	-11.4	-13.0
S4–S1	Electricity	% Difference	0.0	-0.6	8.8	18.6	11.4	10.4	2.6
S5–S1	Electricity	% Difference	0.0	-1.8	-9.9	-19.3	-29.0	-40.8	-55.0
S2–S1	Industry	% Difference	0.0	0.1	0.1	-0.1	0.4	2.1	0.1
S3–S1	Industry	% Difference	0.0	0.1	0.1	-0.1	0.3	2.2	0.2
S4–S1	Industry	% Difference	0.0	0.1	0.2	0.0	-0.5	-0.4	-1.1
S5–S1	Industry	% Difference	0.0	0.6	0.0	-0.3	-0.4	1.0	-1.0
S2–S1	Residential	% Difference	0.0	-0.1	-0.1	0.1	-0.2	-0.2	-0.6
S3–S1	Residential	% Difference	0.0	-0.1	0.0	0.1	-0.2	-0.1	-0.6
S4–S1	Residential	% Difference	0.0	-0.1	0.3	0.6	0.4	0.1	-0.1
S5–S1	Residential	% Difference	0.0	0.0	0.0	0.2	-0.1	0.0	-0.4
S2–S1	Commercial	% Difference	0.0	-0.1	-0.1	0.1	-0.5	-0.5	-1.3
S3–S1	Commercial	% Difference	0.0	-0.1	0.0	0.2	-0.5	-0.4	-1.3
S4–S1	Commercial	% Difference	0.0	-0.1	0.6	1.2	0.8	0.2	-0.4
S5–S1	Commercial	% Difference	0.0	0.0	0.0	0.3	-0.1	0.1	-0.6
S2–S1	Transportation	% Difference	0.0	-0.2	0.2	-1.9	16.0	31.9	38.7
S3–S1	Transportation	% Difference	0.0	-0.1	0.2	-1.1	17.5	33.9	42.2
S4–S1	Transportation	% Difference	0.0	-0.1	-14.6	-24.6	-22.5	-13.6	-7.3
S5–S1	Transportation	% Difference	0.0	-0.4	-0.9	-2.9	14.7	29.6	36.6
S2–S1	**Total**	**% Difference**	**0.0**	**-0.2**	**0.0**	**-0.4**	**-1.1**	**0.3**	**-0.8**
S3–S1	**Total**	**% Difference**	**0.0**	**-0.1**	**-0.7**	**-0.6**	**-1.2**	**-0.2**	**-0.9**
S4–S1	**Total**	**% Difference**	**0.0**	**-0.2**	**2.0**	**3.4**	**1.6**	**1.8**	**-0.3**
S5–S1	**Total**	**% Difference**	**0.0**	**-0.4**	**-2.7**	**-4.9**	**-6.6**	**-8.3**	**-12.3**

*1 Tcf in a non-leap year is equivalent to 2.74 Bcf/d

Table D-29. U.S. sectoral natural gas consumption, S6 and S7, by year (see Figure B-4)

Scenario	Natural Gas Volumes	Units	2020	2025	2030	2035	2040	2045	2050
S6	Electricity	Tcf	11.6	12.9	8.3	5.7	5.0	5.7	6.5
S7	Electricity	Tcf	11.6	12.8	8.5	5.9	5.0	5.7	6.6
S6	Industry	Tcf	10.1	10.5	10.6	15.4	18.8	22.3	28.2
S7	Industry	Tcf	10.1	10.5	10.6	14.7	18.4	22.0	27.8
S6	Residential	Tcf	4.7	4.6	4.6	4.0	3.8	3.8	3.7
S7	Residential	Tcf	4.7	4.6	4.5	4.0	3.8	3.8	3.7
S6	Commercial	Tcf	3.2	3.2	3.2	2.5	2.4	2.3	2.3
S7	Commercial	Tcf	3.2	3.2	3.1	2.5	2.4	2.3	2.3
S6	Transportation	Tcf	0.9	0.8	0.8	0.8	0.9	1.0	1.1
S7	Transportation	Tcf	0.9	0.8	0.8	0.8	0.8	1.0	1.1
S6	**Total**	**Tcf**	**30.5**	**32.0**	**27.4**	**28.4**	**30.8**	**35.0**	**41.9**
S7	**Total**	**Tcf**	**30.5**	**31.9**	**27.5**	**27.9**	**30.5**	**34.7**	**41.5**
S7–S6	Electricity	Tcf	0.0	0.0	0.2	0.2	0.1	0.0	0.1

Scenario	Natural Gas Volumes	Units	2020	2025	2030	2035	2040	2045	2050
	Industry	Tcf	0.0	0.0	0.0	-0.6	-0.4	-0.3	-0.4
	Residential	Tcf	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Commercial	Tcf	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Transportation	Tcf	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Total	**Tcf**	**0.0**	**0.0**	**0.1**	**-0.5**	**-0.3**	**-0.3**	**-0.3**
	Electricity	% Difference	0.0	-0.4	2.0	3.1	1.4	-0.1	1.4
	Industry	% Difference	0.0	0.0	0.1	-4.1	-2.0	-1.3	-1.4
	Residential	% Difference	0.0	0.0	-0.4	-0.1	-0.3	-0.2	-0.3
	Commercial	% Difference	0.0	0.0	-0.5	-0.4	-0.5	-0.5	-0.4
	Transportation	% Difference	0.0	0.4	0.1	-1.1	-0.3	-0.7	0.3
	Total	**% Difference**	**0.0**	**-0.1**	**0.5**	**-1.7**	**-1.1**	**-0.9**	**-0.8**

*1 Tcf in a non-leap year is equivalent to 2.74 Bcf/d

Table D-30. U.S. natural gas consumption for DAC, S6 and S7, by year (see Figure B-5)

Scenario	Units	2020	2025	2030	2035	2040	2045	2050
S6	Tcf	0.0	0.0	0.0	4.7	7.8	11.2	16.8
S7	Tcf	0.0	0.0	0.0	4.1	7.5	10.7	16.2
S7–S6	Tcf	0.0	0.0	0.0	-0.6	-0.4	-0.5	-0.7
	% Difference	0.0	0.0	0.0	-13.0	-4.5	-4.1	-4.0

*1 Tcf in a non-leap year is equivalent to 2.74 Bcf/d

Table D-31. U.S. CO_2 removals by technology, S6 and S7, by year (see Figure B-6)

Scenario	CO_2 Removals	Units	2020	2025	2030	2035	2040	2045	2050
S6	H_2 Biomass	Gt CO_2	0.00	0.00	0.03	0.08	0.12	0.17	0.20
	BECCS	Gt CO_2	0.00	0.00	0.02	0.03	0.04	0.04	0.04
	DAC	Gt CO_2	0.00	0.00	0.00	0.54	0.90	1.28	1.93
	Total	Gt CO_2	**0.00**	**0.00**	**0.05**	**0.65**	**1.06**	**1.49**	**2.16**
S7	H_2 Biomass	Gt CO_2	0.00	0.00	0.05	0.09	0.14	0.21	0.24
	BECCS	Gt CO_2	0.00	0.00	0.02	0.04	0.04	0.04	0.04
	DAC	Gt CO_2	0.00	0.00	0.00	0.47	0.86	1.23	1.85
	Total	Gt CO_2	**0.00**	**0.00**	**0.07**	**0.60**	**1.04**	**1.48**	**2.13**
S7–S6	H_2 Biomass	Gt CO_2	0.00	0.00	0.02	0.01	0.02	0.03	0.04
	BECCS	Gt CO_2	0.00	0.00	0.00	0.00	0.01	0.01	0.01
	DAC	Gt CO_2	0.00	0.00	0.00	-0.07	-0.04	-0.05	-0.08
	Total	Gt CO_2	**0.00**	**0.00**	**0.02**	**-0.05**	**-0.01**	**-0.01**	**-0.03**
	H_2 Biomass	% Difference	0.0	-1.0	79.1	19.1	15.5	20.4	21.6
	BECCS	% Difference	0.0	0.0	15.0	5.5	18.7	18.4	18.8
	DAC	% Difference	0.0	0.0	0.0	-13.0	-4.5	-4.1	-4.0
	Total	**% Difference**	**0.0**	**-1.0**	**52.1**	**-8.3**	**-1.3**	**-0.7**	**-1.2**

Table D-32.Annual export volumes of U.S. LNG, GCAM unadjusted global CO_2 emissions, NETL-adjusted global CO_2 emissions (LHV and HHV) and market adjustment factors for S2 vs. S1 (IPCC AR6-100 GWP) (see Table 4 and Table C-13)

Year	US Export LNG (EJ)			Global CO2e Emissions (Tg) [IPCC AR6-100]														
				GCAM Unadjusted (LHV)			Market Adjustment Factor		NETL Adjusted GCAM (LHV)			Market Adjustment Factor		NETL Adjusted GCAM (HHV)			Market Adjustment Factor	
	S1	S2	Delta S2-S1	S1	S2	Delta S2-S1	Annual	Cumulative	S1	S2	Delta S2-S1	Annual	Cumulative	S1	S2	Delta S2-S1	Annual	Cumulative
2015	0.02	0.02	0.00	49,715	49,715	0.00	NA	NA	49,656	49,656	0.00	NA	NA	49,501	49,501	0.00	NA	NA
2016	0.54	0.54	0.00	50,471	50,471	0.00	NA	NA	50,411	50,411	0.00	NA	NA	50,251	50,251	0.00	NA	NA
2017	1.06	1.06	0.00	51,226	51,226	0.00	NA	NA	51,165	51,165	0.00	NA	NA	51,001	51,001	0.00	NA	NA
2018	1.58	1.58	0.00	51,982	51,982	0.00	NA	NA	51,919	51,919	0.00	NA	NA	51,751	51,751	0.00	NA	NA
2019	2.10	2.10	0.00	52,738	52,738	0.00	NA	NA	52,673	52,673	0.00	NA	NA	52,501	52,501	0.00	NA	NA
2020	2.62	2.62	0.00	53,493	53,493	0.00	NA	NA	53,427	53,427	0.00	NA	NA	53,251	53,251	0.00	NA	NA
2021	3.09	3.09	0.00	52,882	52,882	0.00	NA	NA	52,816	52,816	0.00	NA	NA	52,642	52,642	0.00	NA	NA
2022	3.55	3.55	0.00	52,270	52,270	0.00	NA	NA	52,205	52,205	0.00	NA	NA	52,033	52,033	0.00	NA	NA
2023	4.02	4.02	0.00	51,659	51,659	0.00	NA	NA	51,594	51,594	0.00	NA	NA	51,424	51,424	0.00	NA	NA
2024	4.49	4.49	0.00	51,047	51,047	0.00	NA	NA	50,983	50,983	0.00	NA	NA	50,815	50,815	0.00	NA	NA
2025	4.96	4.96	0.00	50,435	50,435	0.00	NA	NA	50,372	50,372	0.00	NA	NA	50,206	50,206	0.00	NA	NA
2026	5.37	5.37	0.00	50,757	50,757	0.00	NA	NA	50,693	50,693	0.00	NA	NA	50,523	50,523	0.00	NA	NA
2027	5.78	5.78	0.00	51,079	51,079	0.00	NA	NA	51,013	51,013	0.00	NA	NA	50,841	50,841	0.00	NA	NA
2028	6.19	6.19	0.00	51,400	51,400	0.00	NA	NA	51,334	51,334	0.00	NA	NA	51,158	51,158	0.00	NA	NA
2029	6.60	6.60	0.00	51,722	51,722	0.00	NA	NA	51,654	51,654	0.00	NA	NA	51,476	51,476	0.00	NA	NA
2030	7.01	7.01	0.00	52,044	52,044	0.00	NA	NA	51,975	51,975	0.00	NA	NA	51,793	51,793	0.00	NA	NA
2031	7.54	7.46	-0.08	52,044	52,044	0.53	-6.44	-6.44	51,974	51,975	0.54	-6.63	-6.63	51,790	51,791	0.59	-7.15	-7.15
2032	8.07	7.91	-0.16	52,044	52,045	1.06	-6.44	-6.44	51,974	51,975	1.09	-6.63	-6.63	51,788	51,789	1.17	-7.15	-7.15
2033	8.60	8.36	-0.25	52,044	52,046	1.59	-6.44	-6.44	51,973	51,975	1.63	-6.63	-6.63	51,785	51,787	1.76	-7.15	-7.15
2034	9.13	8.81	-0.33	52,045	52,047	2.12	-6.44	-6.44	51,973	51,975	2.18	-6.63	-6.63	51,782	51,785	2.35	-7.15	-7.15
2035	9.66	9.25	-0.41	52,045	52,048	2.64	-6.44	-6.44	51,972	51,975	2.72	-6.63	-6.63	51,780	51,783	2.93	-7.15	-7.15
2036	9.77	10.00	0.23	51,936	51,936	-0.74	-3.22	-7.18	51,863	51,862	-0.73	-3.15	-7.43	51,668	51,668	-0.69	-2.99	-8.10
2037	9.87	10.74	0.87	51,828	51,824	-4.13	-4.73	-23.60	51,754	51,749	-4.18	-4.79	-25.14	51,557	51,553	-4.31	-4.95	-29.24
2038	9.97	11.48	1.51	51,719	51,712	-7.51	-4.97	-3.22	51,644	51,637	-7.63	-5.04	-3.15	51,446	51,438	-7.94	-5.25	-2.99
2039	10.07	12.22	2.15	51,610	51,600	-10.90	-5.06	-4.34	51,535	51,524	-11.08	-5.14	-4.37	51,334	51,323	-11.56	-5.37	-4.44
2040	10.17	12.96	2.79	51,502	51,488	-14.28	-5.11	-4.68	51,425	51,411	-14.53	-5.20	-4.73	51,223	51,208	-15.19	-5.43	-4.88
2041	10.17	13.56	3.39	51,417	51,401	-16.17	-4.77	-4.71	51,340	51,323	-16.38	-4.83	-4.77	51,134	51,117	-16.93	-4.99	-4.92
2042	10.17	14.16	3.99	51,333	51,314	-18.07	-4.53	-4.66	51,254	51,236	-18.23	-4.57	-4.71	51,045	51,027	-18.68	-4.68	-4.85
2043	10.17	14.75	4.58	51,248	51,228	-19.96	-4.35	-4.58	51,168	51,148	-20.09	-4.38	-4.63	50,956	50,936	-20.42	-4.46	-4.75
2044	10.17	15.35	5.18	51,163	51,141	-21.85	-4.22	-4.50	51,082	51,060	-21.94	-4.24	-4.54	50,868	50,845	-22.16	-4.28	-4.65
2045	10.17	15.95	5.78	51,079	51,055	-23.74	-4.11	-4.43	50,996	50,973	-23.79	-4.12	-4.46	50,779	50,755	-23.91	-4.14	-4.55
2046	10.17	16.27	6.10	50,937	50,907	-29.63	-4.86	-4.50	50,854	50,824	-29.63	-4.86	-4.53	50,633	50,604	-29.65	-4.86	-4.60
2047	10.17	16.60	6.43	50,795	50,760	-35.51	-5.52	-4.66	50,711	50,676	-35.47	-5.52	-4.68	50,488	50,453	-35.39	-5.51	-4.74
2048	10.17	16.92	6.75	50,654	50,613	-41.39	-6.13	-4.86	50,569	50,527	-41.31	-6.12	-4.88	50,343	50,302	-41.13	-6.09	-4.93
2049	10.17	17.25	7.08	50,512	50,465	-47.27	-6.68	-5.09	50,426	50,379	-47.16	-6.66	-5.11	50,197	50,151	-46.86	-6.62	-5.14
2050	10.17	17.57	7.40	50,371	50,318	-53.15	-7.18	-5.34	50,283	50,230	-53.00	-7.16	-5.35	50,052	50,000	-52.60	-7.11	-5.37

Table D-33. Annual export volumes of U.S. LNG, GCAM unadjusted global CO2 emissions, NETL-adjusted global CO2 emissions (LHV and HHV) and market adjustment factors for S7 vs. S6 (IPCC AR6-100 GWP) (see Table 5 and Table C-14)

Year	US Export LNG (EJ)			Global CO2e Emissions (Tg) [IPCC AR6-100]															
				GCAM Unadjusted (LHV)			Market Adjustment Factor		NETL Adjusted GCAM (LHV)			Market Adjustment Factor		NETL Adjusted GCAM (HHV)			Market Adjustment Factor	
	S6	S7	Delta S7-S6	S6	S7	Delta S7-S6	Annual	Cumulative	S6	S7	Delta S7-S6	Annual	Cumulative	S6	S7	Delta S7-S6	Annual	Cumulative
2015	0.02	0.02	0.00	49,715	49,715	0.00	NA	NA	49,656	49,656	0.00	NA	NA	49,501	49,501	0.00	NA	NA
2016	0.54	0.54	0.00	50,471	50,471	0.00	NA	NA	50,411	50,411	0.00	NA	NA	50,251	50,251	0.00	NA	NA
2017	1.06	1.06	0.00	51,227	51,227	0.00	NA	NA	51,165	51,165	0.00	NA	NA	51,002	51,002	0.00	NA	NA
2018	1.58	1.58	0.00	51,983	51,983	0.00	NA	NA	51,920	51,920	0.00	NA	NA	51,752	51,752	0.00	NA	NA
2019	2.10	2.10	0.00	52,739	52,739	0.00	NA	NA	52,675	52,675	0.00	NA	NA	52,503	52,503	0.00	NA	NA
2020	2.62	2.62	0.00	53,495	53,495	0.00	NA	NA	53,429	53,429	0.00	NA	NA	53,254	53,254	0.00	NA	NA
2021	3.09	3.09	0.00	52,607	52,607	0.00	NA	NA	52,542	52,542	0.00	NA	NA	52,370	52,370	0.00	NA	NA
2022	3.55	3.55	0.00	51,719	51,719	0.00	NA	NA	51,655	51,655	0.00	NA	NA	51,485	51,485	0.00	NA	NA
2023	4.02	4.02	0.00	50,831	50,831	0.00	NA	NA	50,768	50,768	0.00	NA	NA	50,601	50,601	0.00	NA	NA
2024	4.49	4.49	0.00	49,943	49,943	0.00	NA	NA	49,881	49,881	0.00	NA	NA	49,717	49,717	0.00	NA	NA
2025	4.96	4.96	0.00	49,055	49,055	0.00	NA	NA	48,994	48,994	0.00	NA	NA	48,833	48,833	0.00	NA	NA
2026	5.07	5.07	0.00	49,146	49,146	0.00	NA	NA	49,084	49,084	0.00	NA	NA	48,921	48,921	0.00	NA	NA
2027	5.17	5.17	0.00	49,237	49,237	0.00	NA	NA	49,174	49,174	0.00	NA	NA	49,009	49,009	0.00	NA	NA
2028	5.28	5.28	0.00	49,328	49,328	0.00	NA	NA	49,264	49,264	0.00	NA	NA	49,096	49,096	0.00	NA	NA
2029	5.38	5.38	0.00	49,419	49,419	0.00	NA	NA	49,354	49,354	0.00	NA	NA	49,184	49,184	0.00	NA	NA
2030	5.49	5.49	0.00	49,509	49,509	0.00	NA	NA	49,444	49,444	0.00	NA	NA	49,272	49,272	0.00	NA	NA
2031	5.78	5.78	0.00	48,148	48,148	0.00	411.56	429.06	48,083	48,083	0.00	404.93	423.34	47,910	47,910	0.00	387.36	408.21
2032	6.07	6.07	0.00	46,786	46,786	0.00	408.65	415.45	46,721	46,721	0.00	401.86	409.02	46,549	46,549	0.00	383.89	392.00
2033	6.37	6.37	0.00	45,425	45,425	0.00	407.67	411.56	45,360	45,360	0.00	400.84	404.93	45,187	45,187	0.00	382.73	387.36
2034	6.66	6.66	0.00	44,063	44,063	0.00	407.19	409.81	43,998	43,998	0.00	400.33	403.09	43,826	43,826	0.00	382.15	385.28
2035	6.95	6.95	0.00	42,701	42,701	0.00	406.90	408.84	42,636	42,636	0.00	400.02	402.06	42,465	42,465	0.00	381.81	384.12
2036	7.48	7.48	0.00	41,353	41,353	0.00	288.44	378.24	41,288	41,288	0.00	282.77	371.75	41,116	41,116	0.00	267.78	354.55
2037	8.01	8.01	0.00	40,004	40,004	0.00	175.02	336.35	39,939	39,939	0.00	170.52	330.27	39,767	39,767	0.00	158.60	314.16
2038	8.54	8.54	0.00	38,655	38,655	0.00	66.33	289.39	38,590	38,590	0.00	62.94	283.77	38,418	38,418	0.00	53.97	268.91
2039	9.07	9.07	0.00	37,306	37,306	0.00	-37.93	240.04	37,241	37,241	0.00	-40.25	234.92	37,069	37,069	0.00	-46.39	221.37
2040	9.60	9.60	0.00	35,958	35,958	0.00	-138.02	189.63	35,893	35,893	0.00	-139.31	185.02	35,720	35,720	0.00	-142.74	172.82
2041	9.71	10.01	0.30	34,520	34,519	-0.84	-2.80	-2.75	34,455	34,455	-0.83	-2.76	-2.72	34,284	34,283	-0.80	-2.67	-2.63
2042	9.83	10.43	0.60	33,083	33,081	-1.68	-2.80	-2.78	33,018	33,017	-1.66	-2.76	-2.75	32,847	32,846	-1.60	-2.67	-2.65
2043	9.94	10.84	0.90	31,646	31,643	-2.52	-2.80	-2.79	31,581	31,579	-2.49	-2.76	-2.75	31,411	31,409	-2.40	-2.67	-2.66
2044	10.06	11.26	1.20	30,208	30,205	-3.36	-2.80	-2.79	30,144	30,141	-3.32	-2.76	-2.76	29,975	29,972	-3.20	-2.67	-2.66
2045	10.17	11.67	1.50	28,771	28,767	-4.20	-2.80	-2.79	28,707	28,703	-4.14	-2.76	-2.76	28,538	28,534	-4.00	-2.67	-2.66
2046	10.17	11.84	1.67	27,398	27,393	-4.86	-2.92	-2.83	27,335	27,330	-4.79	-2.87	-2.79	27,168	27,163	-4.58	-2.75	-2.69
2047	10.17	12.00	1.83	26,024	26,019	-5.53	-3.02	-2.87	25,962	25,956	-5.43	-2.96	-2.83	25,797	25,792	-5.16	-2.82	-2.72
2048	10.17	12.17	2.00	24,651	24,644	-6.19	-3.10	-2.92	24,589	24,583	-6.07	-3.04	-2.87	24,426	24,420	-5.74	-2.88	-2.75
2049	10.17	12.33	2.16	23,277	23,270	-6.86	-3.17	-2.96	23,216	23,210	-6.71	-3.11	-2.91	23,055	23,049	-6.32	-2.93	-2.78
2050	10.17	12.50	2.33	21,904	21,896	-7.52	-3.23	-3.01	21,844	21,836	-7.35	-3.16	-2.95	21,685	21,678	-6.91	-2.97	-2.81

Table D-34. Annual export volumes of U.S. LNG, GCAM unadjusted global CO2 emissions, NETL-adjusted global CO2 emissions (LHV and HHV) and market adjustment factors for S2 vs. S1 (IPCC AR6-20 GWP) (see Table C-13)

Year	US Export LNG (EJ)			Global CO2e Emissions (Tg) [IPCC AR6-20]															
				GCAM Unadjusted (LHV)			Market Adjustment Factor		NETL Adjusted GCAM (LHV)			Market Adjustment Factor		NETL Adjusted GCAM (HHV)			Market Adjustment Factor	
	S1	S2	Delta S2-S1	S1	S2	Delta S2-S1	Annual	Cumulative	S1	S2	Delta S2-S1	Annual	Cumulative	S1	S2	Delta S2-S1	Annual	Cumulative
2015	0.02	0.02	0.00	69,184	69,184	0.00	NA	NA	68,757	68,757	0.00	NA	NA	68,525	68,525	0.00	NA	NA
2016	0.54	0.54	0.00	70,161	70,161	0.00	NA	NA	69,724	69,724	0.00	NA	NA	69,486	69,486	0.00	NA	NA
2017	1.06	1.06	0.00	71,139	71,139	0.00	NA	NA	70,691	70,691	0.00	NA	NA	70,448	70,448	0.00	NA	NA
2018	1.58	1.58	0.00	72,117	72,117	0.00	NA	NA	71,658	71,658	0.00	NA	NA	71,409	71,409	0.00	NA	NA
2019	2.10	2.10	0.00	73,094	73,094	0.00	NA	NA	72,625	72,625	0.00	NA	NA	72,371	72,371	0.00	NA	NA
2020	2.62	2.62	0.00	74,072	74,072	0.00	NA	NA	73,593	73,593	0.00	NA	NA	73,332	73,332	0.00	NA	NA
2021	3.09	3.09	0.00	73,117	73,117	0.00	NA	NA	72,646	72,646	0.00	NA	NA	72,390	72,390	0.00	NA	NA
2022	3.55	3.55	0.00	72,162	72,162	0.00	NA	NA	71,700	71,700	0.00	NA	NA	71,448	71,448	0.00	NA	NA
2023	4.02	4.02	0.00	71,207	71,207	0.00	NA	NA	70,753	70,753	0.00	NA	NA	70,507	70,507	0.00	NA	NA
2024	4.49	4.49	0.00	70,252	70,252	0.00	NA	NA	69,807	69,807	0.00	NA	NA	69,565	69,565	0.00	NA	NA
2025	4.96	4.96	0.00	69,297	69,297	0.00	NA	NA	68,860	68,860	0.00	NA	NA	68,623	68,623	0.00	NA	NA
2026	5.37	5.37	0.00	69,837	69,837	0.00	NA	NA	69,394	69,394	0.00	NA	NA	69,152	69,152	0.00	NA	NA
2027	5.78	5.78	0.00	70,378	70,378	0.00	NA	NA	69,927	69,927	0.00	NA	NA	69,681	69,681	0.00	NA	NA
2028	6.19	6.19	0.00	70,918	70,918	0.00	NA	NA	70,460	70,460	0.00	NA	NA	70,211	70,211	0.00	NA	NA
2029	6.60	6.60	0.00	71,458	71,458	0.00	NA	NA	70,993	70,993	0.00	NA	NA	70,740	70,740	0.00	NA	NA
2030	7.01	7.01	0.00	71,999	71,999	0.00	NA	NA	71,526	71,526	0.00	NA	NA	71,269	71,269	0.00	NA	NA
2031	7.54	7.46	-0.08	72,118	72,119	0.99	-12.04	-12.04	71,640	71,641	1.11	-13.50	-13.50	71,380	71,381	1.17	-14.29	-14.29
2032	8.07	7.91	-0.16	72,236	72,238	1.98	-12.04	-12.04	71,754	71,756	2.22	-13.50	-13.50	71,491	71,494	2.35	-14.29	-14.29
2033	8.60	8.36	-0.25	72,355	72,358	2.97	-12.04	-12.04	71,868	71,871	3.33	-13.50	-13.50	71,603	71,606	3.52	-14.29	-14.29
2034	9.13	8.81	-0.33	72,474	72,478	3.96	-12.04	-12.04	71,982	71,986	4.43	-13.50	-13.50	71,714	71,719	4.69	-14.29	-14.29
2035	9.66	9.25	-0.41	72,593	72,598	4.94	-12.04	-12.04	72,096	72,101	5.54	-13.50	-13.50	71,825	71,831	5.87	-14.29	-14.29
2036	9.77	10.00	0.23	72,536	72,534	-1.71	-7.41	-13.11	72,034	72,032	-1.56	-6.75	-15.05	71,761	71,760	-1.47	-6.39	-16.11
2037	9.87	10.74	0.87	72,478	72,470	-8.36	-9.59	-36.67	71,972	71,963	-8.65	-9.93	-49.41	71,697	71,688	-8.81	-10.11	-56.33
2038	9.97	11.48	1.51	72,421	72,406	-15.01	-9.93	-7.41	71,910	71,894	-15.75	-10.42	-6.75	71,633	71,616	-16.15	-10.68	-6.39
2039	10.07	12.22	2.15	72,363	72,341	-21.67	-10.06	-9.03	71,848	71,825	-22.85	-10.61	-9.10	71,568	71,545	-23.50	-10.91	-9.14
2040	10.17	12.96	2.79	72,306	72,277	-28.32	-10.13	-9.52	71,786	71,756	-29.95	-10.72	-9.82	71,504	71,473	-30.84	-11.03	-9.98
2041	10.17	13.56	3.39	72,333	72,302	-30.99	-9.14	-9.38	71,805	71,772	-32.13	-9.48	-9.70	71,517	71,485	-32.76	-9.66	-9.87
2042	10.17	14.16	3.99	72,360	72,326	-33.66	-8.44	-9.11	71,823	71,789	-34.32	-8.61	-9.38	71,531	71,496	-34.67	-8.70	-9.53
2043	10.17	14.75	4.58	72,387	72,351	-36.34	-7.93	-8.81	71,841	71,805	-36.50	-7.96	-9.03	71,544	71,508	-36.59	-7.98	-9.14
2044	10.17	15.35	5.18	72,414	72,375	-39.01	-7.53	-8.53	71,859	71,821	-38.69	-7.47	-8.68	71,558	71,519	-38.51	-7.44	-8.76
2045	10.17	15.95	5.78	72,442	72,400	-41.68	-7.22	-8.27	71,878	71,837	-40.87	-7.08	-8.36	71,571	71,531	-40.43	-7.00	-8.42
2046	10.17	16.27	6.10	72,399	72,350	-48.87	-8.01	-8.23	71,827	71,780	-47.65	-7.81	-8.27	71,516	71,469	-46.98	-7.70	-8.29
2047	10.17	16.60	6.43	72,357	72,301	-56.05	-8.72	-8.30	71,777	71,723	-54.42	-8.47	-8.30	71,462	71,408	-53.54	-8.33	-8.30
2048	10.17	16.92	6.75	72,315	72,251	-63.24	-9.37	-8.45	71,727	71,665	-61.20	-9.06	-8.41	71,407	71,347	-60.09	-8.90	-8.38
2049	10.17	17.25	7.08	72,272	72,202	-70.43	-9.95	-8.64	71,676	71,608	-67.97	-9.60	-8.56	71,352	71,286	-66.64	-9.42	-8.51
2050	10.17	17.57	7.40	72,230	72,152	-77.61	-10.48	-8.86	71,626	71,551	-74.75	-10.10	-8.74	71,298	71,224	-73.19	-9.89	-8.67

Table D-35. Annual export volumes of U.S. LNG, GCAM unadjusted global CO2 emissions, NETL-adjusted global CO2 emissions (LHV and HHV) and market adjustment factors for S7 vs. S6 (IPCC AR6-20 GWP) (see Table C-14)

Year	US Export LNG (EJ)			Global CO2e Emissions (Tg) [IPCC AR6-20]																
				GCAM Unadjusted (LHV)			Market Adjustment Factor		NETL Adjusted GCAM (LHV)			Market Adjustment Factor		NETL Adjusted GCAM (HHV)			Market Adjustment Factor	
	S6	S7	Delta S7-S6	S6	S7	Delta S7-S6	Annual	Cumulative	S6	S7	Delta S7-S6	Annual	Cumulative	S6	S7	Delta S7-S6	Annual	Cumulative
2015	0.02	0.02	0.00	69,184	69,184	0.00	NA	NA	68,757	68,757	0.00	NA	NA	68,525	68,525	0.00	NA	NA
2016	0.54	0.54	0.00	70,161	70,161	0.00	NA	NA	69,723	69,723	0.00	NA	NA	69,486	69,486	0.00	NA	NA
2017	1.06	1.06	0.00	71,138	71,138	0.00	NA	NA	70,690	70,690	0.00	NA	NA	70,447	70,447	0.00	NA	NA
2018	1.58	1.58	0.00	72,115	72,115	0.00	NA	NA	71,657	71,657	0.00	NA	NA	71,407	71,407	0.00	NA	NA
2019	2.10	2.10	0.00	73,092	73,092	0.00	NA	NA	72,623	72,623	0.00	NA	NA	72,368	72,368	0.00	NA	NA
2020	2.62	2.62	0.00	74,069	74,069	0.00	NA	NA	73,590	73,590	0.00	NA	NA	73,329	73,329	0.00	NA	NA
2021	3.09	3.09	0.00	72,761	72,761	0.00	NA	NA	72,294	72,294	0.00	NA	NA	72,041	72,041	0.00	NA	NA
2022	3.55	3.55	0.00	71,453	71,453	0.00	NA	NA	70,999	70,999	0.00	NA	NA	70,752	70,752	0.00	NA	NA
2023	4.02	4.02	0.00	70,145	70,145	0.00	NA	NA	69,703	69,703	0.00	NA	NA	69,463	69,463	0.00	NA	NA
2024	4.49	4.49	0.00	68,837	68,837	0.00	NA	NA	68,408	68,408	0.00	NA	NA	68,174	68,174	0.00	NA	NA
2025	4.96	4.96	0.00	67,529	67,529	0.00	NA	NA	67,112	67,112	0.00	NA	NA	66,886	66,886	0.00	NA	NA
2026	5.07	5.07	0.00	67,811	67,811	0.00	NA	NA	67,389	67,389	0.00	NA	NA	67,160	67,160	0.00	NA	NA
2027	5.17	5.17	0.00	68,093	68,093	0.00	NA	NA	67,666	67,666	0.00	NA	NA	67,434	67,434	0.00	NA	NA
2028	5.28	5.28	0.00	68,375	68,375	0.00	NA	NA	67,943	67,943	0.00	NA	NA	67,708	67,708	0.00	NA	NA
2029	5.38	5.38	0.00	68,657	68,657	0.00	NA	NA	68,220	68,220	0.00	NA	NA	67,983	67,983	0.00	NA	NA
2030	5.49	5.49	0.00	68,939	68,939	0.00	NA	NA	68,497	68,497	0.00	NA	NA	68,257	68,257	0.00	NA	NA
2031	5.78	5.78	0.00	67,509	67,509	0.00	1927.27	1918.14	67,069	67,069	0.00	1870.76	1869.94	66,829	66,829	0.00	1840.05	1843.75
2032	6.07	6.07	0.00	66,080	66,080	0.01	1928.79	1925.24	65,640	65,640	0.01	1870.90	1870.58	65,402	65,402	0.01	1839.43	1840.87
2033	6.37	6.37	0.00	64,650	64,650	0.01	1929.30	1927.27	64,212	64,212	0.01	1870.94	1870.76	63,974	63,974	0.01	1839.23	1840.05
2034	6.66	6.66	0.00	63,220	63,220	0.01	1929.55	1928.18	62,784	62,784	0.01	1870.97	1870.84	62,546	62,546	0.01	1839.12	1839.68
2035	6.95	6.95	0.00	61,791	61,791	0.02	1929.71	1928.69	61,355	61,355	0.02	1870.98	1870.89	61,119	61,119	0.02	1839.06	1839.47
2036	7.48	7.48	0.00	60,367	60,367	0.01	1412.52	1797.51	59,932	59,932	0.01	1364.94	1742.30	59,695	59,695	0.01	1339.08	1712.30
2037	8.01	8.01	0.00	58,943	58,943	0.01	917.34	1616.07	58,508	58,508	0.01	880.43	1564.64	58,272	58,272	0.01	860.37	1536.68
2038	8.54	8.54	0.00	57,519	57,519	0.00	442.80	1412.02	57,084	57,084	0.00	416.11	1364.89	56,848	56,848	0.00	401.61	1339.28
2039	9.07	9.07	0.00	56,095	56,095	0.00	-12.38	1197.27	55,661	55,661	0.00	-29.25	1154.70	55,425	55,425	0.00	-38.43	1131.56
2040	9.60	9.60	0.00	54,671	54,671	0.00	-449.35	977.72	54,237	54,237	0.00	-456.81	939.83	54,001	54,001	0.00	-460.86	919.24
2041	9.71	10.01	0.30	53,069	53,067	-2.01	-6.69	-6.44	52,637	52,635	-1.86	-6.21	-5.97	52,402	52,400	-1.79	-5.95	-5.72
2042	9.83	10.43	0.60	51,467	51,463	-4.01	-6.68	-6.60	51,037	51,033	-3.72	-6.20	-6.12	50,803	50,800	-3.57	-5.94	-5.87
2043	9.94	10.84	0.90	49,865	49,859	-6.02	-6.68	-6.64	49,437	49,432	-5.58	-6.20	-6.16	49,204	49,199	-5.35	-5.94	-5.90
2044	10.06	11.26	1.20	48,263	48,255	-8.02	-6.68	-6.66	47,837	47,830	-7.44	-6.20	-6.18	47,605	47,598	-7.13	-5.94	-5.92
2045	10.17	11.67	1.50	46,661	46,651	-10.02	-6.68	-6.66	46,237	46,228	-9.30	-6.20	-6.18	46,007	45,998	-8.91	-5.94	-5.92
2046	10.17	11.84	1.67	45,204	45,192	-11.68	-7.01	-6.76	44,784	44,774	-10.73	-6.44	-6.25	44,557	44,546	-10.22	-6.13	-5.98
2047	10.17	12.00	1.83	43,746	43,732	-13.34	-7.29	-6.88	43,332	43,319	-12.16	-6.64	-6.34	43,107	43,095	-11.52	-6.29	-6.05
2048	10.17	12.17	2.00	42,288	42,273	-15.00	-7.52	-7.01	41,879	41,865	-13.59	-6.81	-6.44	41,657	41,644	-12.83	-6.43	-6.13
2049	10.17	12.33	2.16	40,830	40,813	-16.66	-7.71	-7.13	40,426	40,411	-15.03	-6.95	-6.53	40,207	40,193	-14.13	-6.54	-6.20
2050	10.17	12.50	2.33	39,372	39,354	-18.32	-7.88	-7.25	38,973	38,957	-16.46	-7.07	-6.61	38,757	38,741	-15.44	-6.64	-6.27

Table D-36. Annual export volumes of U.S. LNG, GCAM unadjusted global CO2 emissions, NETL-adjusted global CO2 emissions (LHV and HHV) and market adjustment factors for S2 vs. S1 (IPCC AR5-100 GWP with carbon climate feedback) (see Table C-13)

Year	US Export LNG (EJ)			Global CO2e Emissions (Tg) [IPCC AR5-100]															
				GCAM Unadjusted (LHV)			Market Adjustment Factor		NETL Adjusted GCAM (LHV)			Market Adjustment Factor		NETL Adjusted GCAM (HHV)			Market Adjustment Factor	
	S1	S2	Delta S2-S1	S1	S2	Delta S2-S1	Annual	Cumulative	S1	S2	Delta S2-S1	Annual	Cumulative	S1	S2	Delta S2-S1	Annual	Cumulative
2015	0.02	0.02	0.00	52,227	52,227	0.00	NA	NA	52,127	52,127	0.00	NA	NA	51,987	51,987	0.00	NA	NA
2016	0.54	0.54	0.00	53,006	53,006	0.00	NA	NA	52,903	52,903	0.00	NA	NA	52,760	52,760	0.00	NA	NA
2017	1.06	1.06	0.00	53,784	53,784	0.00	NA	NA	53,679	53,679	0.00	NA	NA	53,532	53,532	0.00	NA	NA
2018	1.58	1.58	0.00	54,563	54,563	0.00	NA	NA	54,455	54,455	0.00	NA	NA	54,304	54,304	0.00	NA	NA
2019	2.10	2.10	0.00	55,341	55,341	0.00	NA	NA	55,231	55,231	0.00	NA	NA	55,076	55,076	0.00	NA	NA
2020	2.62	2.62	0.00	56,120	56,120	0.00	NA	NA	56,007	56,007	0.00	NA	NA	55,849	55,849	0.00	NA	NA
2021	3.09	3.09	0.00	55,469	55,469	0.00	NA	NA	55,357	55,357	0.00	NA	NA	55,201	55,201	0.00	NA	NA
2022	3.55	3.55	0.00	54,817	54,817	0.00	NA	NA	54,707	54,707	0.00	NA	NA	54,553	54,553	0.00	NA	NA
2023	4.02	4.02	0.00	54,166	54,166	0.00	NA	NA	54,058	54,058	0.00	NA	NA	53,905	53,905	0.00	NA	NA
2024	4.49	4.49	0.00	53,515	53,515	0.00	NA	NA	53,408	53,408	0.00	NA	NA	53,257	53,257	0.00	NA	NA
2025	4.96	4.96	0.00	52,864	52,864	0.00	NA	NA	52,758	52,758	0.00	NA	NA	52,609	52,609	0.00	NA	NA
2026	5.37	5.37	0.00	53,210	53,210	0.00	NA	NA	53,103	53,103	0.00	NA	NA	52,951	52,951	0.00	NA	NA
2027	5.78	5.78	0.00	53,557	53,557	0.00	NA	NA	53,447	53,447	0.00	NA	NA	53,293	53,293	0.00	NA	NA
2028	6.19	6.19	0.00	53,903	53,903	0.00	NA	NA	53,791	53,791	0.00	NA	NA	53,634	53,634	0.00	NA	NA
2029	6.60	6.60	0.00	54,249	54,249	0.00	NA	NA	54,135	54,135	0.00	NA	NA	53,976	53,976	0.00	NA	NA
2030	7.01	7.01	0.00	54,595	54,595	0.00	NA	NA	54,480	54,480	0.00	NA	NA	54,318	54,318	0.00	NA	NA
2031	7.54	7.46	-0.08	54,611	54,612	0.60	-7.28	-7.28	54,495	54,495	0.63	-7.62	-7.62	54,330	54,331	0.66	-8.08	-8.08
2032	8.07	7.91	-0.16	54,628	54,629	1.20	-7.28	-7.28	54,509	54,511	1.25	-7.62	-7.62	54,343	54,345	1.33	-8.08	-8.08
2033	8.60	8.36	-0.25	54,644	54,645	1.79	-7.28	-7.28	54,524	54,526	1.88	-7.62	-7.62	54,356	54,358	1.99	-8.08	-8.08
2034	9.13	8.81	-0.33	54,660	54,662	2.39	-7.28	-7.28	54,539	54,541	2.50	-7.62	-7.62	54,369	54,372	2.65	-8.08	-8.08
2035	9.66	9.25	-0.41	54,676	54,679	2.99	-7.28	-7.28	54,554	54,557	3.13	-7.62	-7.62	54,382	54,385	3.32	-8.08	-8.08
2036	9.77	10.00	0.23	54,576	54,575	-0.92	-4.01	-8.04	54,453	54,452	-0.90	-3.90	-8.47	54,280	54,279	-0.86	-3.74	-9.08
2037	9.87	10.74	0.87	54,477	54,472	-4.84	-5.55	-24.70	54,352	54,347	-4.92	-5.65	-27.40	54,177	54,172	-5.04	-5.79	-31.20
2038	9.97	11.48	1.51	54,377	54,368	-8.76	-5.79	-4.01	54,251	54,242	-8.95	-5.92	-3.90	54,075	54,065	-9.22	-6.10	-3.74
2039	10.07	12.22	2.15	54,278	54,265	-12.67	-5.88	-5.15	54,151	54,138	-12.98	-6.03	-5.19	53,972	53,959	-13.40	-6.22	-5.25
2040	10.17	12.96	2.79	54,178	54,161	-16.59	-5.94	-5.50	54,050	54,033	-17.00	-6.08	-5.59	53,870	53,852	-17.58	-6.29	-5.71
2041	10.17	13.56	3.39	54,113	54,094	-18.55	-5.47	-5.49	53,983	53,964	-18.88	-5.57	-5.58	53,800	53,781	-19.35	-5.71	-5.71
2042	10.17	14.16	3.99	54,048	54,027	-20.50	-5.14	-5.39	53,916	53,895	-20.76	-5.21	-5.47	53,730	53,709	-21.12	-5.30	-5.59
2043	10.17	14.75	4.58	53,983	53,961	-22.46	-4.90	-5.27	53,849	53,826	-22.64	-4.94	-5.34	53,660	53,637	-22.89	-4.99	-5.44
2044	10.17	15.35	5.18	53,918	53,894	-24.42	-4.71	-5.14	53,782	53,757	-24.52	-4.73	-5.20	53,591	53,566	-24.66	-4.76	-5.29
2045	10.17	15.95	5.78	53,853	53,827	-26.38	-4.57	-5.03	53,715	53,688	-26.40	-4.57	-5.08	53,521	53,494	-26.42	-4.58	-5.15
2046	10.17	16.27	6.10	53,728	53,696	-32.37	-5.31	-5.08	53,588	53,556	-32.32	-5.30	-5.12	53,391	53,359	-32.24	-5.28	-5.17
2047	10.17	16.60	6.43	53,603	53,564	-38.36	-5.97	-5.21	53,461	53,423	-38.23	-5.95	-5.24	53,262	53,224	-38.06	-5.92	-5.29
2048	10.17	16.92	6.75	53,478	53,433	-44.35	-6.57	-5.40	53,334	53,290	-44.15	-6.54	-5.43	53,133	53,089	-43.88	-6.50	-5.46
2049	10.17	17.25	7.08	53,353	53,302	-50.34	-7.11	-5.62	53,207	53,157	-50.07	-7.07	-5.64	53,003	52,954	-49.69	-7.02	-5.66
2050	10.17	17.57	7.40	53,228	53,171	-56.33	-7.61	-5.85	53,081	53,025	-55.99	-7.56	-5.86	52,874	52,819	-55.51	-7.50	-5.87

Table D- 37. Annual export volumes of U.S. LNG, GCAM unadjusted global CO2 emissions, NETL-adjusted global CO2 emissions (LHV and HHV) and market adjustment factors for S7 vs. S6 (IPCC AR5-100 GWP with carbon climate feedback) (see Table C-14)

Year	US Export LNG (EJ)			Global CO2e Emissions (Tg) [IPCC AR5-100]															
				GCAM Unadjusted (LHV)			Market Adjustment Factor		NETL Adjusted GCAM (LHV)			Market Adjustment Factor		NETL Adjusted GCAM (HHV)			Market Adjustment Factor	
	S6	S7	Delta S7-S6	S6	S7	Delta S7-S6	Annual	Cumulative	S6	S7	Delta S7-S6	Annual	Cumulative	S6	S7	Delta S7-S6	Annual	Cumulative
2015	0.02	0.02	0.00	52,227	52,227	0.00	NA	NA	52,127	52,127	0.00	NA	NA	51,987	51,987	0.00	NA	NA
2016	0.54	0.54	0.00	53,006	53,006	0.00	NA	NA	52,904	52,904	0.00	NA	NA	52,760	52,760	0.00	NA	NA
2017	1.06	1.06	0.00	53,785	53,785	0.00	NA	NA	53,680	53,680	0.00	NA	NA	53,533	53,533	0.00	NA	NA
2018	1.58	1.58	0.00	54,564	54,564	0.00	NA	NA	54,456	54,456	0.00	NA	NA	54,305	54,305	0.00	NA	NA
2019	2.10	2.10	0.00	55,342	55,342	0.00	NA	NA	55,232	55,232	0.00	NA	NA	55,078	55,078	0.00	NA	NA
2020	2.62	2.62	0.00	56,121	56,121	0.00	NA	NA	56,009	56,009	0.00	NA	NA	55,850	55,850	0.00	NA	NA
2021	3.09	3.09	0.00	55,184	55,184	0.00	NA	NA	55,074	55,074	0.00	NA	NA	54,918	54,918	0.00	NA	NA
2022	3.55	3.55	0.00	54,247	54,247	0.00	NA	NA	54,139	54,139	0.00	NA	NA	53,986	53,986	0.00	NA	NA
2023	4.02	4.02	0.00	53,310	53,310	0.00	NA	NA	53,204	53,204	0.00	NA	NA	53,054	53,054	0.00	NA	NA
2024	4.49	4.49	0.00	52,373	52,373	0.00	NA	NA	52,269	52,269	0.00	NA	NA	52,122	52,122	0.00	NA	NA
2025	4.96	4.96	0.00	51,436	51,436	0.00	NA	NA	51,334	51,334	0.00	NA	NA	51,190	51,190	0.00	NA	NA
2026	5.07	5.07	0.00	51,548	51,548	0.00	NA	NA	51,445	51,445	0.00	NA	NA	51,299	51,299	0.00	NA	NA
2027	5.17	5.17	0.00	51,661	51,661	0.00	NA	NA	51,556	51,556	0.00	NA	NA	51,409	51,409	0.00	NA	NA
2028	5.28	5.28	0.00	51,774	51,774	0.00	NA	NA	51,667	51,667	0.00	NA	NA	51,518	51,518	0.00	NA	NA
2029	5.38	5.38	0.00	51,886	51,886	0.00	NA	NA	51,778	51,778	0.00	NA	NA	51,627	51,627	0.00	NA	NA
2030	5.49	5.49	0.00	51,999	51,999	0.00	NA	NA	51,889	51,889	0.00	NA	NA	51,736	51,736	0.00	NA	NA
2031	5.78	5.78	0.00	50,632	50,632	0.00	583.58	598.39	50,523	50,523	0.00	571.88	588.33	50,369	50,369	0.00	555.45	574.21
2032	6.07	6.07	0.00	49,265	49,265	0.00	581.11	586.87	49,156	49,156	0.00	569.14	575.53	49,003	49,003	0.00	552.33	559.62
2033	6.37	6.37	0.00	47,898	47,898	0.00	580.29	583.58	47,789	47,789	0.00	568.22	571.88	47,636	47,636	0.00	551.29	555.45
2034	6.66	6.66	0.00	46,531	46,531	0.00	579.88	582.10	46,422	46,422	0.00	567.77	570.23	46,269	46,269	0.00	550.77	553.58
2035	6.95	6.95	0.00	45,164	45,164	0.01	579.63	581.28	45,055	45,055	0.01	567.49	569.32	44,902	44,902	0.00	550.45	552.54
2036	7.48	7.48	0.00	43,810	43,810	0.00	415.33	539.10	43,702	43,702	0.00	405.37	527.65	43,549	43,549	0.00	391.39	511.58
2037	8.01	8.01	0.00	42,457	42,457	0.00	258.01	481.16	42,348	42,348	0.00	250.14	470.45	42,196	42,196	0.00	239.10	455.41
2038	8.54	8.54	0.00	41,104	41,104	0.00	107.25	416.13	40,995	40,995	0.00	101.38	406.26	40,842	40,842	0.00	93.15	392.41
2039	9.07	9.07	0.00	39,750	39,750	0.00	-37.36	347.76	39,642	39,642	0.00	-41.30	338.78	39,489	39,489	0.00	-46.85	326.18
2040	9.60	9.60	0.00	38,397	38,397	0.00	-176.18	277.90	38,288	38,288	0.00	-178.28	269.84	38,136	38,136	0.00	-181.24	258.53
2041	9.71	10.01	0.30	36,949	36,948	-0.99	-3.30	-3.23	36,841	36,840	-0.97	-3.23	-3.16	36,689	36,688	-0.94	-3.13	-3.06
2042	9.83	10.43	0.60	35,501	35,499	-1.98	-3.30	-3.28	35,393	35,391	-1.94	-3.23	-3.21	35,242	35,240	-1.88	-3.13	-3.11
2043	9.94	10.84	0.90	34,053	34,050	-2.97	-3.30	-3.29	33,946	33,943	-2.91	-3.23	-3.22	33,795	33,792	-2.82	-3.13	-3.12
2044	10.06	11.26	1.20	32,606	32,602	-3.96	-3.30	-3.29	32,499	32,495	-3.88	-3.23	-3.22	32,348	32,345	-3.75	-3.13	-3.12
2045	10.17	11.67	1.50	31,158	31,153	-4.95	-3.30	-3.29	31,051	31,046	-4.84	-3.23	-3.22	30,901	30,897	-4.69	-3.13	-3.12
2046	10.17	11.84	1.67	29,779	29,774	-5.73	-3.44	-3.33	29,674	29,668	-5.58	-3.35	-3.26	29,526	29,521	-5.37	-3.22	-3.15
2047	10.17	12.00	1.83	28,401	28,395	-6.51	-3.56	-3.38	28,297	28,291	-6.32	-3.45	-3.30	28,151	28,145	-6.05	-3.30	-3.18
2048	10.17	12.17	2.00	27,023	27,016	-7.29	-3.65	-3.44	26,920	26,913	-7.06	-3.54	-3.35	26,776	26,769	-6.73	-3.37	-3.22
2049	10.17	12.33	2.16	25,644	25,636	-8.07	-3.74	-3.49	25,543	25,535	-7.80	-3.61	-3.39	25,400	25,393	-7.41	-3.43	-3.26
2050	10.17	12.50	2.33	24,266	24,257	-8.85	-3.81	-3.54	24,166	24,157	-8.53	-3.67	-3.44	24,025	24,017	-8.09	-3.48	-3.29

Table D-38. Annual export volumes of U.S. LNG, GCAM unadjusted global CO2 emissions, NETL-adjusted global CO2 emissions (LHV and HHV) and market adjustment factors for S2 vs. S1 (IPCC AR5-20 GWP with carbon climate feedback) (see Table C-13)

Year	US Export LNG (EJ)			Global CO2e Emissions (Tg) [IPCC AR5-20]														
				GCAM Unadjusted (LHV)			Market Adjustment Factor		NETL Adjusted GCAM (LHV)			Market Adjustment Factor		NETL Adjusted GCAM (HHV)			Market Adjustment Factor	
	S1	S2	Delta S2-S1	S1	S2	Delta S2-S1	Annual	Cumulative	S1	S2	Delta S2-S1	Annual	Cumulative	S1	S2	Delta S2-S1	Annual	Cumulative
2015	0.02	0.02	0.00	70,148	70,148	0.00	NA	NA	69,961	69,961	0.00	NA	NA	69,457	69,457	0.00	NA	NA
2016	0.54	0.54	0.00	71,127	71,127	0.00	NA	NA	70,935	70,935	0.00	NA	NA	70,420	70,420	0.00	NA	NA
2017	1.06	1.06	0.00	72,106	72,106	0.00	NA	NA	71,910	71,910	0.00	NA	NA	71,382	71,382	0.00	NA	NA
2018	1.58	1.58	0.00	73,085	73,085	0.00	NA	NA	72,884	72,884	0.00	NA	NA	72,344	72,344	0.00	NA	NA
2019	2.10	2.10	0.00	74,065	74,065	0.00	NA	NA	73,859	73,859	0.00	NA	NA	73,306	73,306	0.00	NA	NA
2020	2.62	2.62	0.00	75,044	75,044	0.00	NA	NA	74,834	74,834	0.00	NA	NA	74,268	74,268	0.00	NA	NA
2021	3.09	3.09	0.00	74,063	74,063	0.00	NA	NA	73,857	73,857	0.00	NA	NA	73,302	73,302	0.00	NA	NA
2022	3.55	3.55	0.00	73,083	73,083	0.00	NA	NA	72,880	72,880	0.00	NA	NA	72,336	72,336	0.00	NA	NA
2023	4.02	4.02	0.00	72,103	72,103	0.00	NA	NA	71,904	71,904	0.00	NA	NA	71,369	71,369	0.00	NA	NA
2024	4.49	4.49	0.00	71,122	71,122	0.00	NA	NA	70,927	70,927	0.00	NA	NA	70,403	70,403	0.00	NA	NA
2025	4.96	4.96	0.00	70,142	70,142	0.00	NA	NA	69,951	69,951	0.00	NA	NA	69,437	69,437	0.00	NA	NA
2026	5.37	5.37	0.00	70,684	70,684	0.00	NA	NA	70,490	70,490	0.00	NA	NA	69,967	69,967	0.00	NA	NA
2027	5.78	5.78	0.00	71,226	71,226	0.00	NA	NA	71,029	71,029	0.00	NA	NA	70,498	70,498	0.00	NA	NA
2028	6.19	6.19	0.00	71,768	71,768	0.00	NA	NA	71,567	71,567	0.00	NA	NA	71,028	71,028	0.00	NA	NA
2029	6.60	6.60	0.00	72,310	72,310	0.00	NA	NA	72,106	72,106	0.00	NA	NA	71,559	71,559	0.00	NA	NA
2030	7.01	7.01	0.00	72,852	72,852	0.00	NA	NA	72,645	72,645	0.00	NA	NA	72,089	72,089	0.00	NA	NA
2031	7.54	7.46	-0.08	72,976	72,977	1.02	-12.40	-12.40	72,767	72,768	1.07	-13.04	-13.04	72,205	72,206	1.21	-14.76	-14.76
2032	8.07	7.91	-0.16	73,100	73,102	2.04	-12.40	-12.40	72,889	72,891	2.14	-13.04	-13.04	72,321	72,323	2.42	-14.76	-14.76
2033	8.60	8.36	-0.25	73,224	73,227	3.05	-12.40	-12.40	73,010	73,013	3.21	-13.04	-13.04	72,436	72,440	3.64	-14.76	-14.76
2034	9.13	8.81	-0.33	73,347	73,351	4.07	-12.40	-12.40	73,132	73,136	4.28	-13.04	-13.04	72,552	72,557	4.85	-14.76	-14.76
2035	9.66	9.25	-0.41	73,471	73,476	5.09	-12.40	-12.40	73,254	73,259	5.35	-13.04	-13.04	72,668	72,674	6.06	-14.76	-14.76
2036	9.77	10.00	0.23	73,418	73,416	-1.87	-8.10	-13.39	73,198	73,196	-1.80	-7.81	-14.24	72,608	72,606	-1.62	-7.02	-16.54
2037	9.87	10.74	0.87	73,364	73,355	-8.82	-10.13	-35.28	73,142	73,133	-8.95	-10.27	-40.88	72,547	72,538	-9.29	-10.66	-55.96
2038	9.97	11.48	1.51	73,310	73,294	-15.78	-10.43	-8.10	73,087	73,071	-16.11	-10.65	-7.81	72,486	72,469	-16.97	-11.22	-7.02
2039	10.07	12.22	2.15	73,257	73,234	-22.74	-10.56	-9.60	73,031	73,008	-23.26	-10.80	-9.63	72,426	72,401	-24.65	-11.45	-9.71
2040	10.17	12.96	2.79	73,203	73,173	-29.70	-10.63	-10.05	72,976	72,945	-30.41	-10.88	-10.18	72,365	72,333	-32.33	-11.57	-10.53
2041	10.17	13.56	3.39	73,240	73,208	-32.43	-9.56	-9.88	73,009	72,976	-32.93	-9.71	-10.02	72,387	72,353	-34.26	-10.10	-10.38
2042	10.17	14.16	3.99	73,277	73,242	-35.17	-8.82	-9.57	73,042	73,007	-35.44	-8.89	-9.69	72,410	72,374	-36.19	-9.08	-10.00
2043	10.17	14.75	4.58	73,314	73,276	-37.90	-8.27	-9.25	73,075	73,037	-37.96	-8.28	-9.34	72,433	72,394	-38.13	-8.32	-9.58
2044	10.17	15.35	5.18	73,351	73,310	-40.63	-7.84	-8.94	73,108	73,068	-40.48	-7.81	-9.00	72,455	72,415	-40.06	-7.74	-9.17
2045	10.17	15.95	5.78	73,388	73,345	-43.36	-7.51	-8.65	73,141	73,098	-42.99	-7.44	-8.69	72,478	72,436	-42.00	-7.27	-8.80
2046	10.17	16.27	6.10	73,352	73,302	-50.59	-8.29	-8.59	73,102	73,052	-50.03	-8.20	-8.61	72,429	72,381	-48.55	-7.96	-8.65
2047	10.17	16.60	6.43	73,317	73,259	-57.81	-9.00	-8.65	73,063	73,006	-57.08	-8.88	-8.65	72,380	72,325	-55.10	-8.57	-8.64
2048	10.17	16.92	6.75	73,281	73,216	-65.03	-9.63	-8.79	73,024	72,960	-64.12	-9.50	-8.77	72,332	72,270	-61.65	-9.13	-8.71
2049	10.17	17.25	7.08	73,245	73,173	-72.25	-10.21	-8.97	72,985	72,914	-71.16	-10.05	-8.93	72,283	72,215	-68.20	-9.64	-8.83
2050	10.17	17.57	7.40	73,210	73,130	-79.48	-10.74	-9.18	72,946	72,867	-78.20	-10.56	-9.12	72,235	72,160	-74.75	-10.10	-8.98

Table D-39. Annual export volumes of U.S. LNG, GCAM unadjusted global CO2 emissions, NETL-adjusted global CO2 emissions (LHV and HHV) and market adjustment factors for S7 vs. S6 (IPCC AR5-20 GWP with carbon climate feedback) (see Table C-14)

Year	US Export LNG (EJ)			Global CO2e Emissions (Tg) [IPCC AR5-20]														
				GCAM Unadjusted (LHV)			Market Adjustment Factor		NETL Adjusted GCAM (LHV)			Market Adjustment Factor		NETL Adjusted GCAM (HHV)			Market Adjustment Factor	
	S6	S7	Delta S7-S6	S6	S7	Delta S7-S6	Annual	Cumulative	S6	S7	Delta S7-S6	Annual	Cumulative	S6	S7	Delta S7-S6	Annual	Cumulative
2015	0.02	0.02	0.00	70,148	70,148	0.00	NA	NA	69,961	69,961	0.00	NA	NA	69,457	69,457	0.00	NA	NA
2016	0.54	0.54	0.00	71,126	71,126	0.00	NA	NA	70,935	70,935	0.00	NA	NA	70,419	70,419	0.00	NA	NA
2017	1.06	1.06	0.00	72,105	72,105	0.00	NA	NA	71,909	71,909	0.00	NA	NA	71,381	71,381	0.00	NA	NA
2018	1.58	1.58	0.00	73,083	73,083	0.00	NA	NA	72,883	72,883	0.00	NA	NA	72,342	72,342	0.00	NA	NA
2019	2.10	2.10	0.00	74,062	74,062	0.00	NA	NA	73,857	73,857	0.00	NA	NA	73,304	73,304	0.00	NA	NA
2020	2.62	2.62	0.00	75,041	75,041	0.00	NA	NA	74,831	74,831	0.00	NA	NA	74,265	74,265	0.00	NA	NA
2021	3.09	3.09	0.00	73,704	73,704	0.00	NA	NA	73,500	73,500	0.00	NA	NA	72,949	72,949	0.00	NA	NA
2022	3.55	3.55	0.00	72,368	72,368	0.00	NA	NA	72,169	72,169	0.00	NA	NA	71,633	71,633	0.00	NA	NA
2023	4.02	4.02	0.00	71,031	71,031	0.00	NA	NA	70,838	70,838	0.00	NA	NA	70,317	70,317	0.00	NA	NA
2024	4.49	4.49	0.00	69,695	69,695	0.00	NA	NA	69,507	69,507	0.00	NA	NA	69,001	69,001	0.00	NA	NA
2025	4.96	4.96	0.00	68,358	68,358	0.00	NA	NA	68,176	68,176	0.00	NA	NA	67,685	67,685	0.00	NA	NA
2026	5.07	5.07	0.00	68,642	68,642	0.00	NA	NA	68,457	68,457	0.00	NA	NA	67,961	67,961	0.00	NA	NA
2027	5.17	5.17	0.00	68,925	68,925	0.00	NA	NA	68,738	68,738	0.00	NA	NA	68,236	68,236	0.00	NA	NA
2028	5.28	5.28	0.00	69,209	69,209	0.00	NA	NA	69,020	69,020	0.00	NA	NA	68,511	68,511	0.00	NA	NA
2029	5.38	5.38	0.00	69,492	69,492	0.00	NA	NA	69,301	69,301	0.00	NA	NA	68,787	68,787	0.00	NA	NA
2030	5.49	5.49	0.00	69,775	69,775	0.00	NA	NA	69,582	69,582	0.00	NA	NA	69,062	69,062	0.00	NA	NA
2031	5.78	5.78	0.00	68,343	68,343	0.00	2010.04	2001.26	68,150	68,150	0.00	1985.16	1980.04	67,632	67,632	0.00	1918.23	1922.98
2032	6.07	6.07	0.00	66,910	66,910	0.01	2011.51	2008.09	66,718	66,718	0.01	1986.01	1984.02	66,201	66,201	0.01	1917.44	1919.29
2033	6.37	6.37	0.00	65,477	65,477	0.01	2011.99	2010.04	65,286	65,286	0.01	1986.30	1985.16	64,771	64,771	0.01	1917.18	1918.23
2034	6.66	6.66	0.00	64,045	64,045	0.01	2012.24	2010.92	63,854	63,854	0.01	1986.44	1985.67	63,341	63,341	0.01	1917.04	1917.76
2035	6.95	6.95	0.00	62,612	62,612	0.02	2012.39	2011.41	62,422	62,422	0.02	1986.52	1985.95	61,910	61,910	0.02	1916.96	1917.49
2036	7.48	7.48	0.00	61,187	61,187	0.01	1473.80	1874.78	60,997	60,997	0.01	1452.85	1850.47	60,486	60,486	0.01	1396.52	1785.09
2037	8.01	8.01	0.00	59,763	59,763	0.01	958.13	1685.82	59,573	59,573	0.01	941.89	1663.17	59,061	59,061	0.01	898.22	1602.27
2038	8.54	8.54	0.00	58,338	58,338	0.00	463.94	1473.32	58,148	58,148	0.00	452.22	1452.57	57,637	57,637	0.00	420.68	1396.78
2039	9.07	9.07	0.00	56,913	56,913	0.00	-10.07	1249.67	56,723	56,723	0.00	-17.47	1230.94	56,213	56,213	0.00	-37.36	1180.55
2040	9.60	9.60	0.00	55,488	55,488	0.00	-465.13	1021.03	55,298	55,298	0.00	-468.37	1004.36	54,788	54,788	0.00	-477.09	959.53
2041	9.71	10.01	0.30	53,889	53,887	-2.09	-6.97	-6.71	53,700	53,698	-2.03	-6.76	-6.50	53,192	53,190	-1.86	-6.18	-5.94
2042	9.83	10.43	0.60	52,289	52,285	-4.18	-6.96	-6.88	52,101	52,097	-4.05	-6.75	-6.67	51,596	51,592	-3.71	-6.17	-6.10
2043	9.94	10.84	0.90	50,690	50,684	-6.27	-6.96	-6.92	50,503	50,497	-6.08	-6.75	-6.71	50,000	49,994	-5.56	-6.17	-6.13
2044	10.06	11.26	1.20	49,091	49,082	-8.36	-6.96	-6.94	48,904	48,896	-8.10	-6.75	-6.72	48,403	48,396	-7.41	-6.17	-6.15
2045	10.17	11.67	1.50	47,491	47,481	-10.45	-6.96	-6.94	47,306	47,296	-10.13	-6.74	-6.73	46,807	46,798	-9.26	-6.17	-6.16
2046	10.17	11.84	1.67	46,036	46,023	-12.17	-7.30	-7.04	45,852	45,841	-11.74	-7.05	-6.82	45,360	45,349	-10.61	-6.37	-6.21
2047	10.17	12.00	1.83	44,580	44,566	-13.89	-7.58	-7.16	44,399	44,385	-13.36	-7.30	-6.93	43,912	43,900	-11.95	-6.53	-6.28
2048	10.17	12.17	2.00	43,124	43,108	-15.61	-7.82	-7.29	42,945	42,930	-14.98	-7.51	-7.04	42,464	42,451	-13.30	-6.66	-6.36
2049	10.17	12.33	2.16	41,668	41,650	-17.33	-8.02	-7.42	41,491	41,475	-16.60	-7.68	-7.16	41,017	41,002	-14.65	-6.78	-6.43
2050	10.17	12.50	2.33	40,212	40,193	-19.05	-8.19	-7.55	40,038	40,019	-18.22	-7.83	-7.26	39,569	39,553	-15.99	-6.88	-6.51

From: Harker Steele, Amanda J.
Sent: Wed, 2 Aug 2023 17:56:28 +0000
To: Easley, Kevin; Skone, Timothy
Cc: Adder, Justin (NETL); Curry, Thomas; Sweeney, Amy
Subject: LNG Report with Notes on Comments Received on report and via email (7/28)
Attachments: Draft_Env.Review_Task4_LNG_LNGRegAnalysisSupport_FWP-DraftPreDecisional_8_2_23.docx

Hi Kevin and Tim,

Thank you both for meeting with the team this week to walk through the comments we received both in-text and via email regarding the DRAFT Env. Addendum Update Report.

I believe the meetings were very helpful, were good use of time for the team, and help to keep this moving forward in the right direction.

I have attached the marked up DRAFT Addendum (8-2-23) which includes the comments we received on 7/28 and some notes from the meetings that have occurred this week between M-W.

The attached is the version I will send to NETL's technical editor who will create the comment resolution matrix. Her resolution matrix will also contain comments we received in the 7/28 email.

I am still nailing down a return date for submitting the next version of the report. We are aiming for Friday, August 11th but I need to secure that date with the team to be 100% sure. If we go past the 11th it would be by no more than 1-2 business days. I know we need to get this returned ASAP as this needs to be completed by the end of the month but I want to ensure anything we resubmit is of the highest quality possible and sufficiently addresses the comments that each of you took the time to make.

I will let you know ASAP the anticipated return date. Thank you all for your time!

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*

[1]National Energy Technology Laboratory (NETL)
[2]NETL support contractor
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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 [ST5R4]: Understood - thank you.

Suggested Citation:
H. Singh, M. Marquis, O. Bostick, R. Wallace, and A. Harker Steele, "Potential Environmental Impacts Associated with Unconventional Natural Gas," National Energy Technology Laboratory, Pittsburgh, July 21, 2023.

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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.

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~~le~~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).

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.?

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.

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

Commented [HSAJ21R20]: Adjusted

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

- **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

[b] 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).

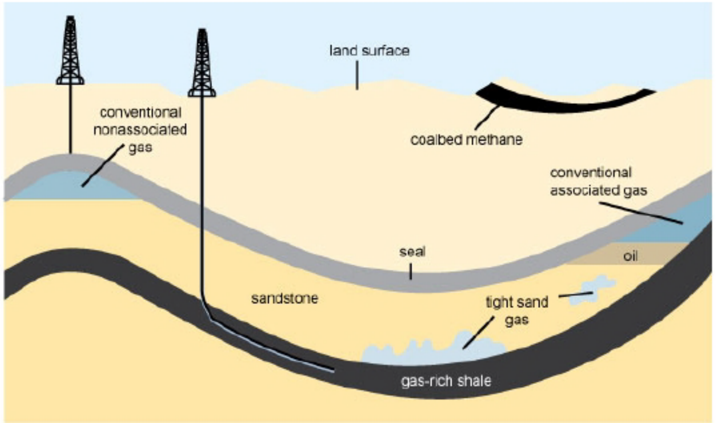
The i~~I~~nternal pressure caused by the fracturing of the rock formation also releases fluid, which travels to the surface through the wellbore. This fluid is commonly referred to as “flowback” or “produced water” and may contain the injected chemicals in addition to any naturally occurring materials 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).

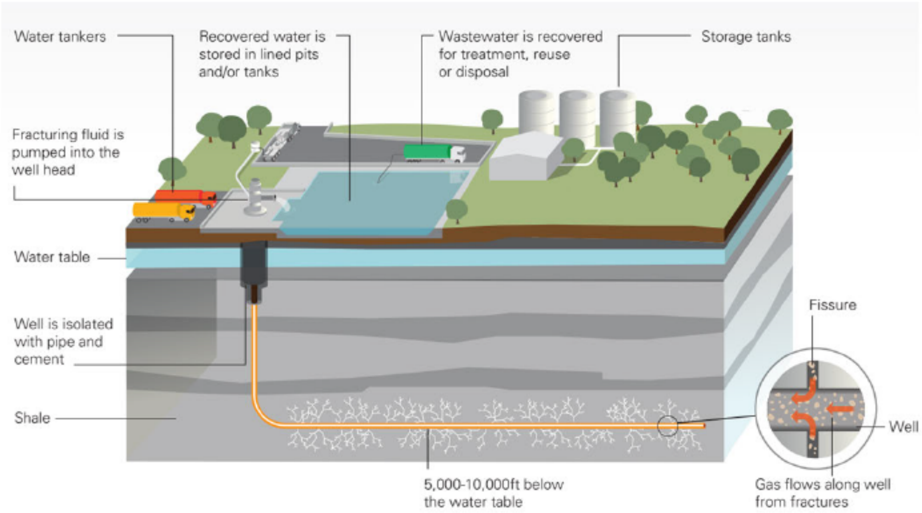
[c] The specific types of chemical additives used, and the proportions of each, depend on the type of rock formation that is being fractured. Additives function as friction reducers, biocides, oxygen (O_2) scavengers, stabilizers, and acids, all of which are necessary to optimize production. The composition 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.

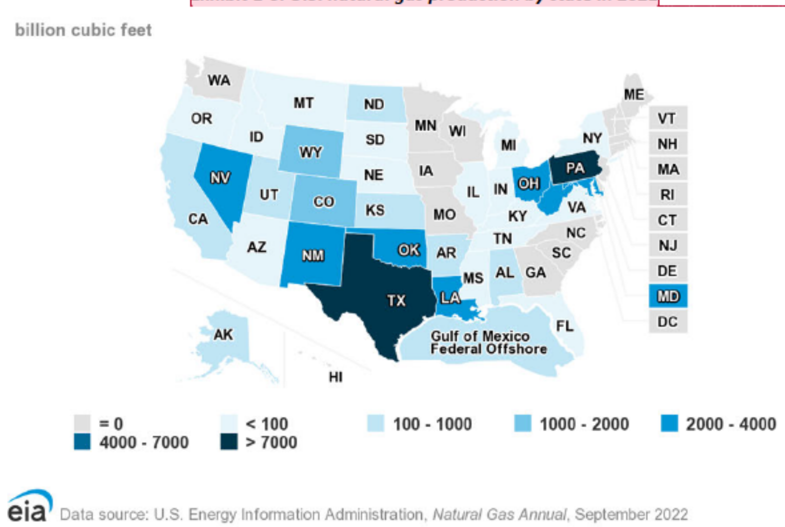
1.1.1 Liquefied Natural Gas

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~~5~~ 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.

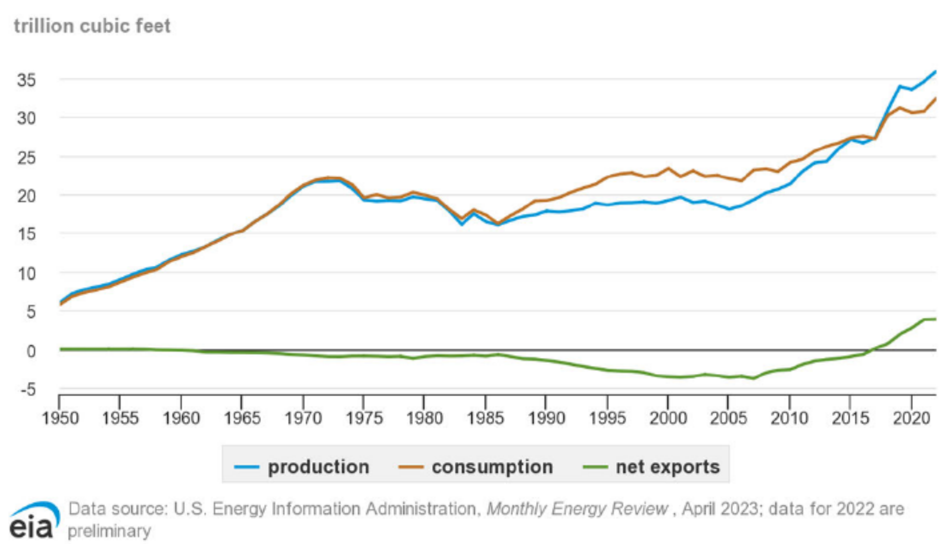
Commented [HSAJ27R25]: Add paragraph on 2021 dry production national volume to set up explanation.

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.

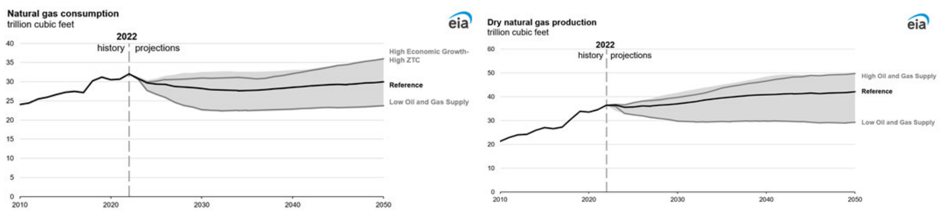
Exhibit 1-4. U.S. natural gas consumption, dry production, and net exports (1950–2022)



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).~~

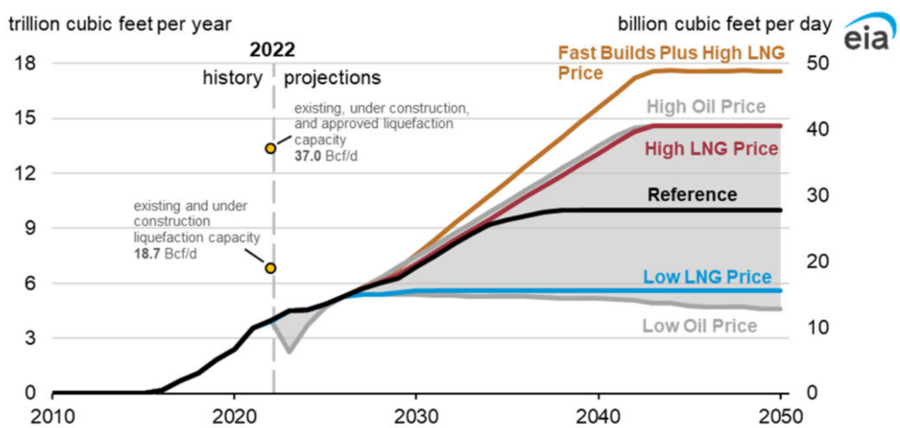
~~*Exhibit 1-5. Natural gas consumption and dry production projections through 2050*~~



~~*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*~~



Data source: U.S. Energy Information Administration, *Annual Energy Outlook 2023 (AEO2023)* and LNG Capacity Tracker
Note: Existing, under construction, and approved LNG capacities are baseload capacities. Shaded regions represent maximum and minimum values for each projection year across the AEO2023 Reference case and side cases.

~~*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.

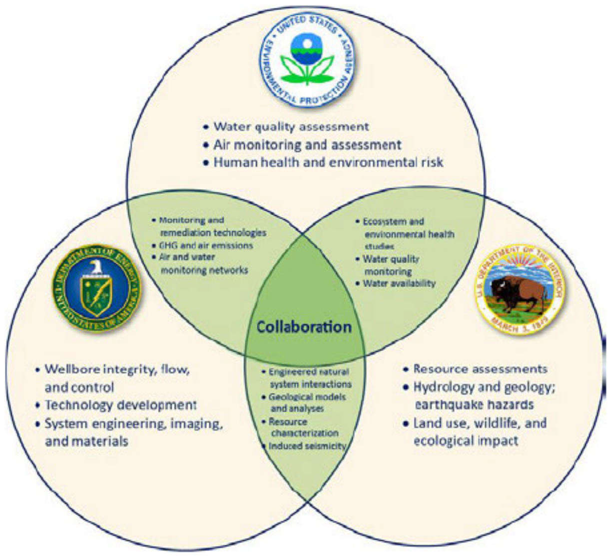
1.3.1 Federal

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 natural gas environmental impacts ~~both associated and not associated with natural gas production.~~ 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 (CAA).

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 (OSHA), 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	✓	●	●[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 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 ~~person~~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-~~

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.

[d] 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 of 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 (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.~~, 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.[e]

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~~lean 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~~atural 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 (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 (USCG), 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

[e] "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 (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. ~~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 (RFI) ~~P~~was issued by FECM to obtain input to inform DOE's research and development (R&D) ~~P~~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 RFI~~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, ~~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.

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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2 Greenhouse Gas Emissions and Climate Change

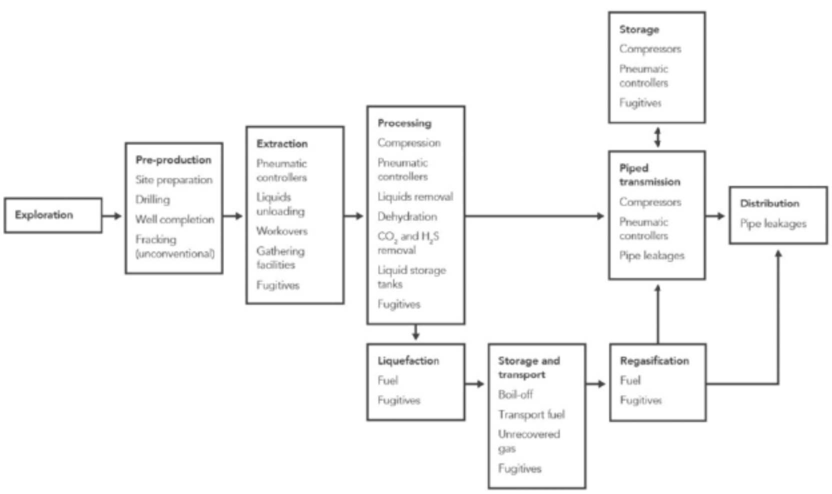
CH_4 and CO_2 emissions from the LNG life cycle ~~and natural gas end uses~~ vary widely across different regions and supply chains. This section presents a review of contemporary (2014 and after) life cycle analysis (LCA) as it pertains to LNG and natural gas GHG emissions.

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 ~~atmosphers~~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.

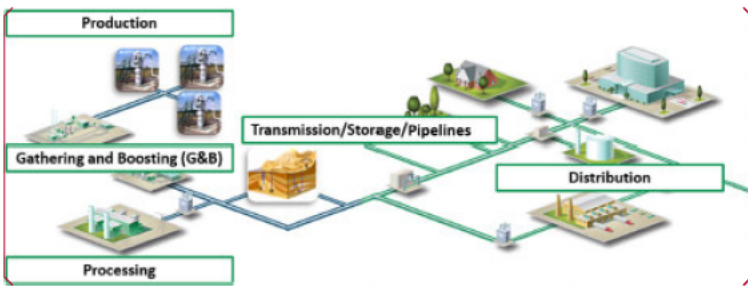
[g] The GHG results in the NETL (2019) report supersede the GHG results in the previous NETL reports.

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:

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. In Exhibit 2-4, ~~T~~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, respectively, 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.

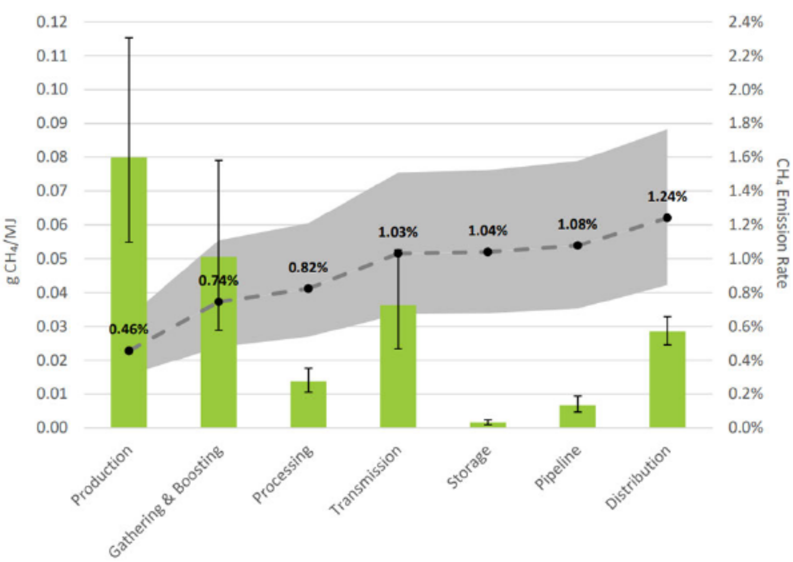
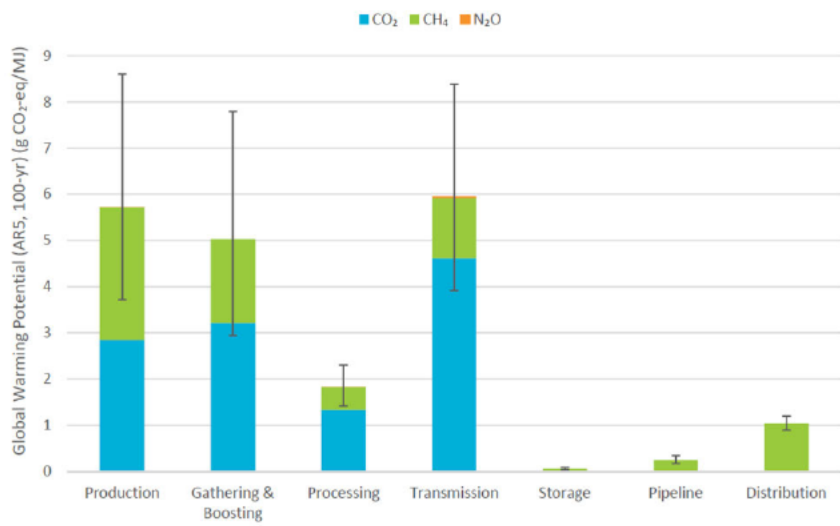


Exhibit 2-4. Life cycle GHG emissions for the U.S. natural gas supply chain



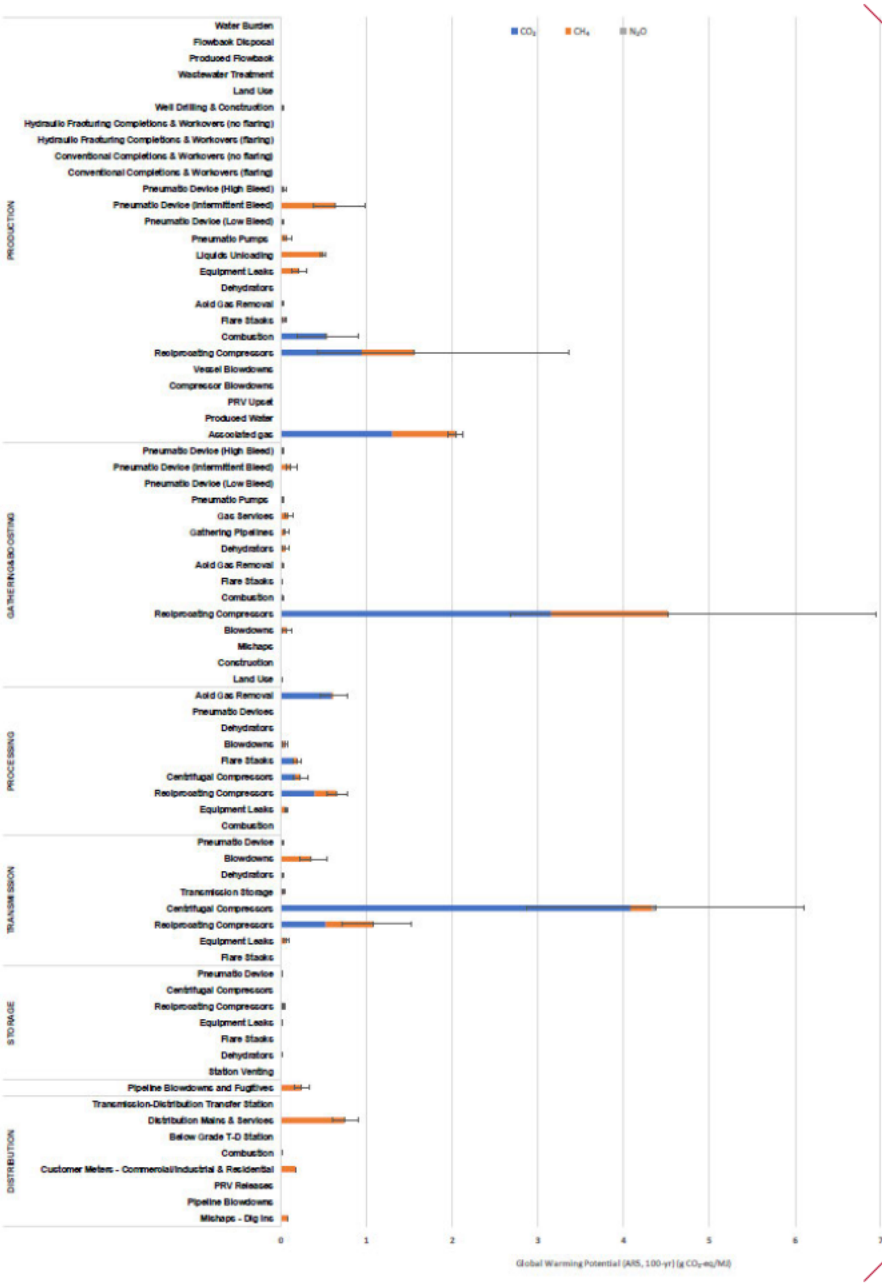
Key drivers of GHG emissions results for the entire natural gas supply chain are illustrated in Exhibit 2-5 (NETL, 2019). Pneumatic devices and compression systems represent a significant portion of the total life cycle GHG emissions associated with the natural gas supply chain (NETL, 2019). Pneumatic 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

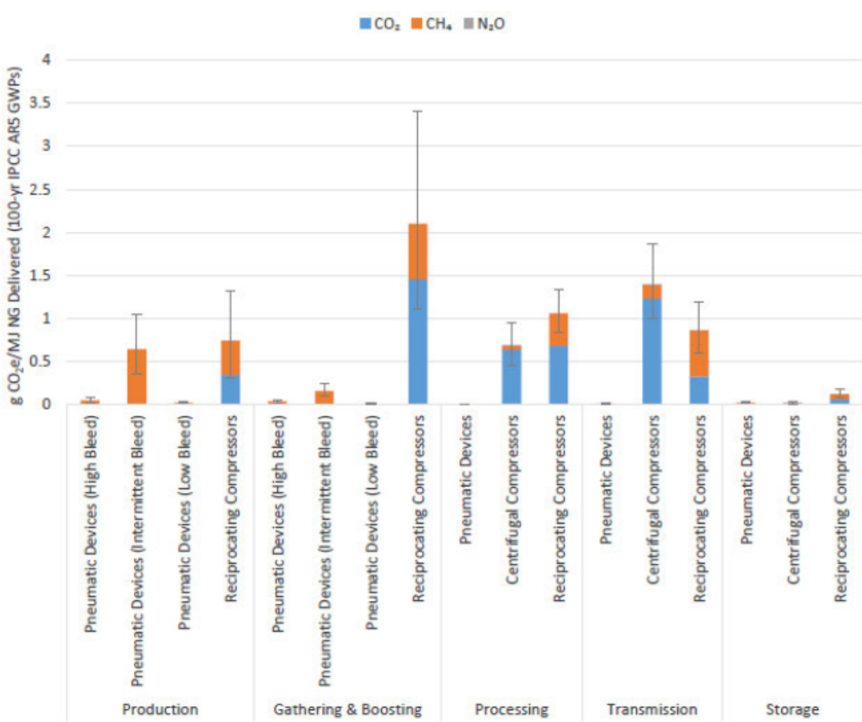


Commented [TS80]: State what year the data represents in the caption and what scope? US average for transmission and distribution combined?

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~~s~~), 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.

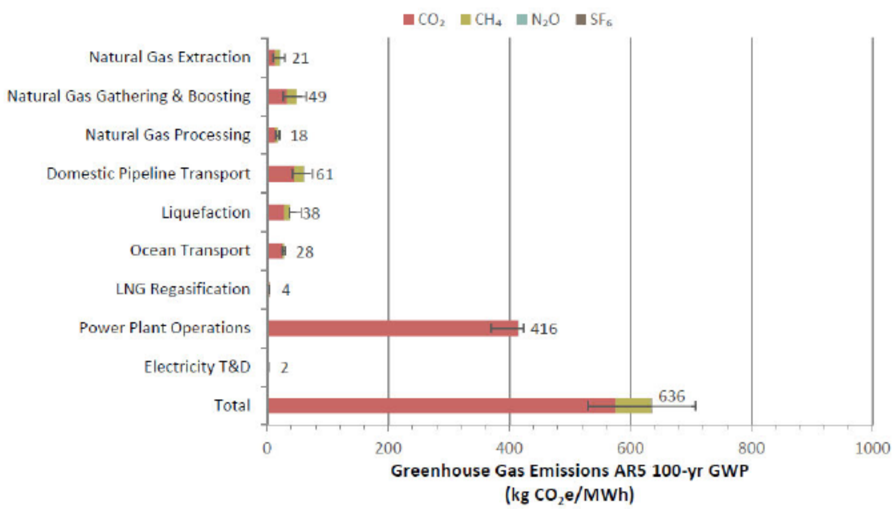
The above bullet provides a more generic way of describing episodic emissions. My concern was calling out specifically liquids unloading and workovers.

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

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.

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

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.

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~~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, thereby~~us, 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

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 reflected in the~~that~~ Rutherford et al. (2021) study estimate of the contribution from super-emitters (top 5 percent of emissions events). Given that the 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?

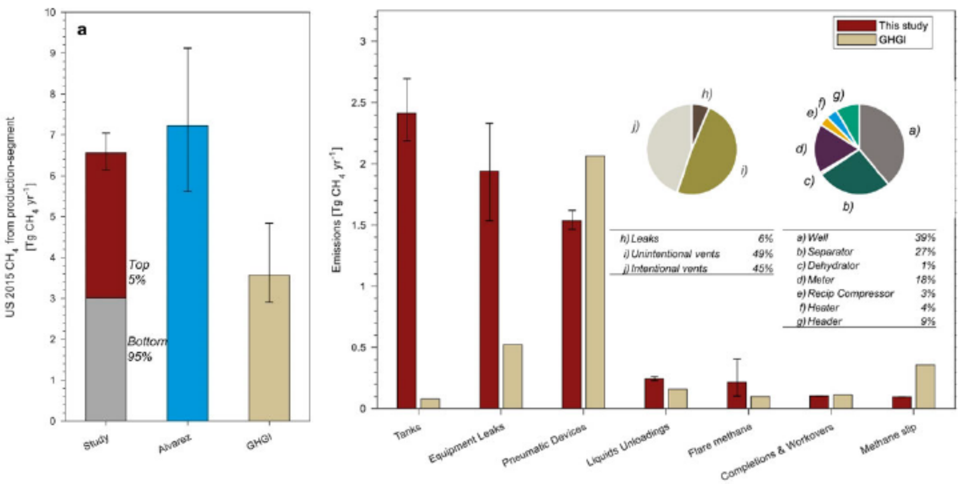
Commented [HSAJ95R94]: Revise sentence.

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

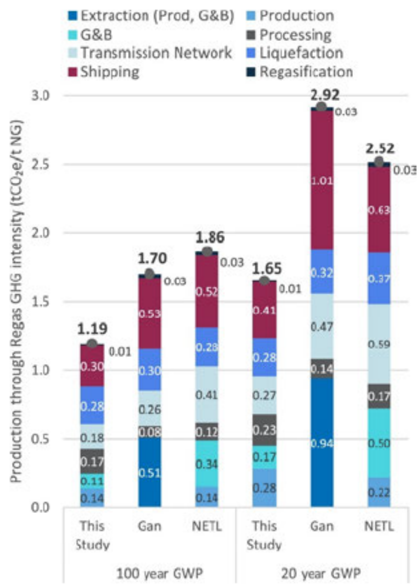
Commented [LBD98]: Comment applicable to other sections as well – is text being updated with more recent studies? (apologies if updating is ongoing in some sections and I'm not aware of it) Most or all of these studies (aside from NETL's) are >10 years old.

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~~. E~~ - each 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 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. ~~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 vehicle~~s~~ types from a wells-to-wheels perspective. In short, the Cai et al. (2017) study concluded ~~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.

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 vent~~ings~~ 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~~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 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 rich~~lean~~ 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.

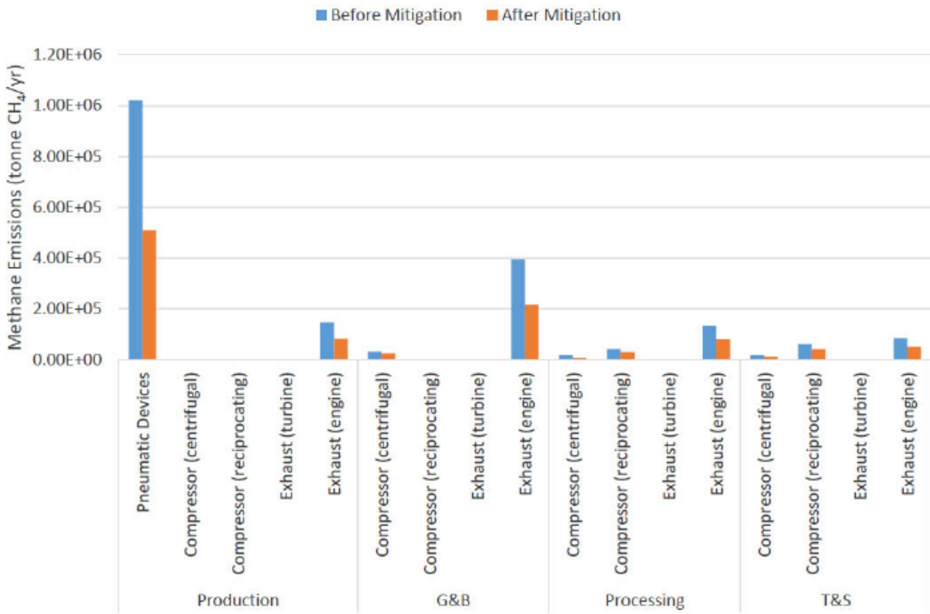
Commented [EK109]: NETL Team - with this proposed text correction, is the statement now accurate?

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 (CCS), CH_4 abatement, and efficiency upgrades contributing 43 percent, 12 percent, and 5 percent, respectively— and this suggested mitigation falls within national responsibilities, 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

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 (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. 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 measurers needed to manage greater risks.

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

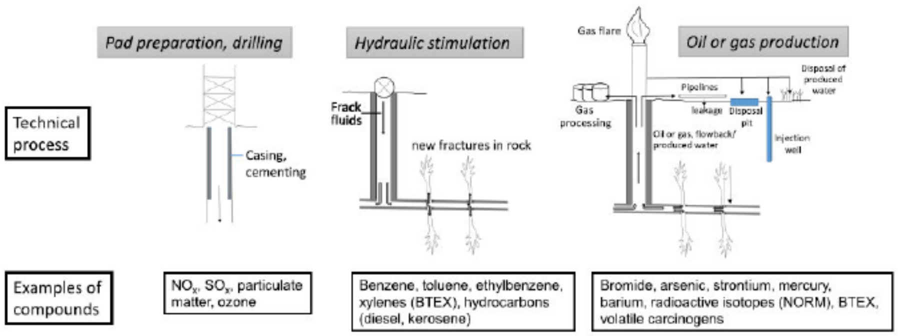
Commented [SW124R123]: I think that would be helpful.

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 (NAAQS) only places limits on six Criteria Air Pollutants including CO, ozone near the surface, NOx, PM, SO_2, and lead. Since the NAAQS~~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~~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~~~~Therefore, national regulations for the breadth of air emissions released during hydraulic fracturing are insufficient.~~ Exhibit 3-2 offers a perspective on non-GHG ~~a~~ir 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

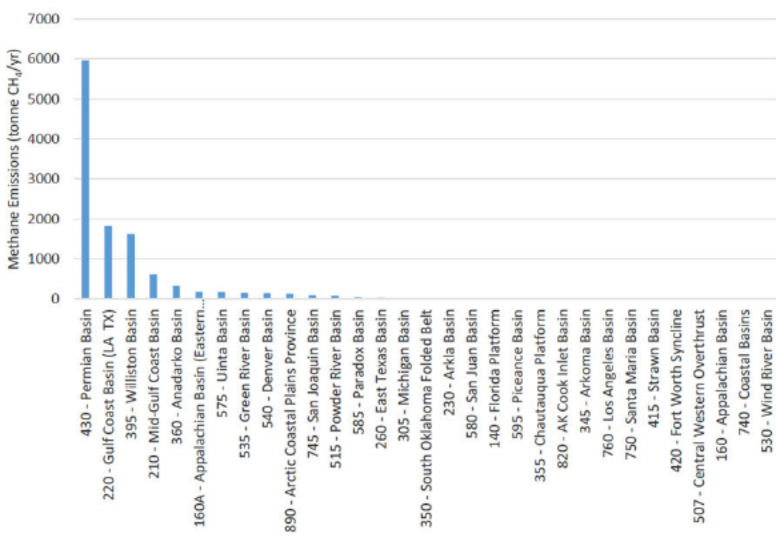
Permission pending from Wollin et al. (2020)

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



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.

3.2 Midstream Transport Emissions

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.

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~~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~~ important for conducting both air quality and health-focused evaluations of natural gas releases.

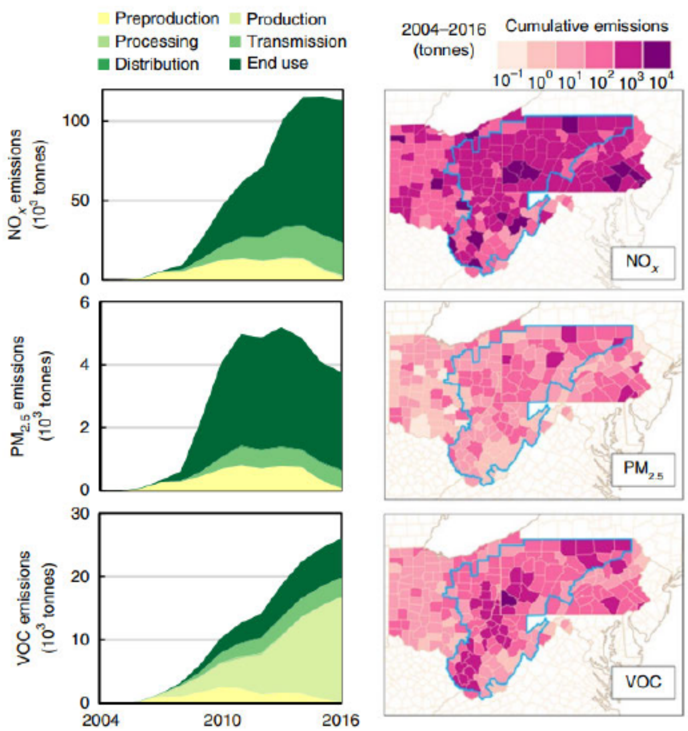
3.3 End-Use Processes

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).

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

Congressional Research Service (CRS). (2020). Methane and Other Air Pollution Issues in Natural Gas Systems. https://crsreports.congress.gov R42986

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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 20154 to ~~2014~~2015, 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?

Commented [RW140R139]: Done

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.

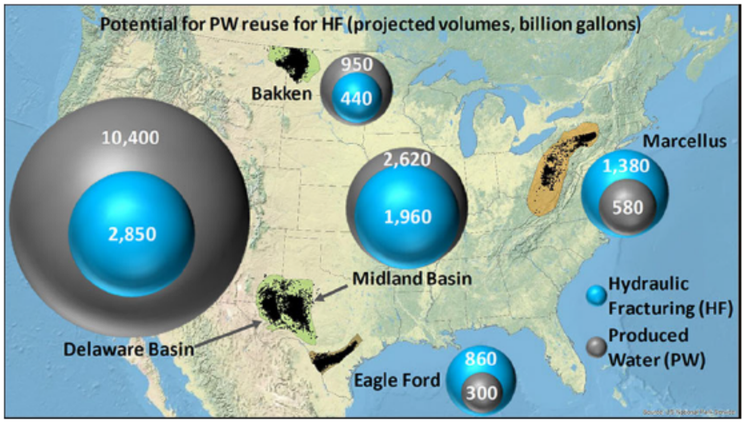
The shale boom has made energy more available and affordable globally, but has also contributed to environmental concerns surrounding the use of water. Scanlon et al. (2020) analyze the water-related sustainability of energy extraction. They focus on meeting the rapidly rising water demand for hydraulic 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 of water use 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 [LBD141]: Volumes of water use?

Commented [RW142R141]: changed

Water issues related to both fracking water demand and produced water supplies may be partially mitigated through the reuse of produced water to frack~~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 gigajoule~~s~~) 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 [HSAJ143]: 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 [HH144R143]: 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

Commented [EK145]: HH: Note about induced seismicity, which has become one of the main reasons for regulatory "Sticks" that are driving technological innovation.

Commented [HSAJ146R145]: Induced seismicity is in response to injection rather than depletion. Double check with HH.

Commented [HSAJ147R145]:

Commented [HSAJ148R145]: Don't include here

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

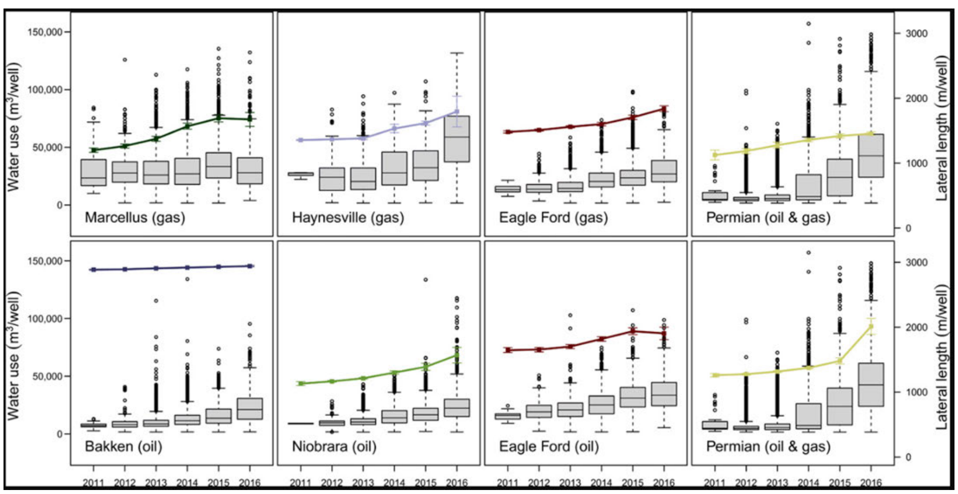
During 2009–2017, ~73,000 wells, or an aggregated total lateral length of ~440 × 10^6 ft (134,000 km), were drilled in the eight studied plays, equivalent to ~3× the Earth's circumference (40,000 km). Dieter et al. (2018) ~~find~~ found that to fracture the rock along that length, a total of ~480 B gal 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.

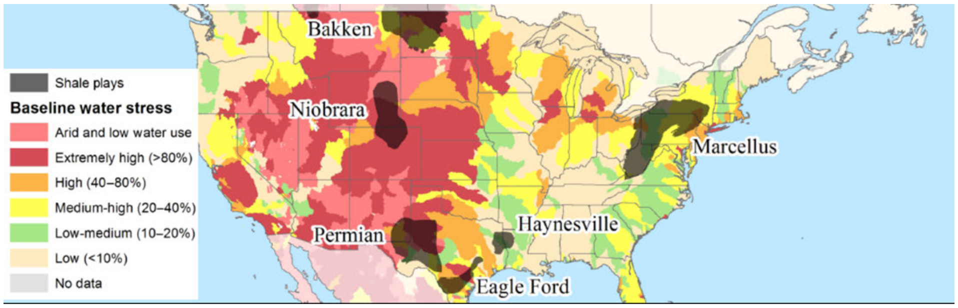
Exhibit 4-3. Water usage and lateral length by shale play



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 extensivel~~t~~y. 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 [RH149]: 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 [RW150R149]: Will rephrase, and thank you for the reference.

Commented [LBD151]: 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 [RW152R151]: understood

Commented [LBD153]: 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 [RW154R153]: Understood. Additionally, I have come across a new reference with respect to suspended solids and NORMs that I will be adding to this section.

Commented [EK155]: 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.

Commented [RW156R155]: Will do.

- 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 [HH157]: 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

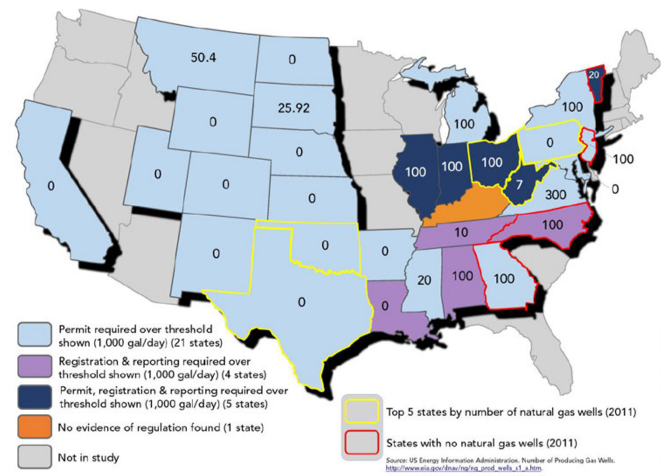
https://www.gwpc.org/wp-content/uploads/2023/06/2023-Produced-Water-Report-Update-FINAL-REPORT.pdf

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

Commented [TC158]: Please remove this section.

Commented [LBD159]: 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 ~~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.[k]

Commented [EK160]: 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.

[k] 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 [EK161]: 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 [EK162]: 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?

Commented [RW163R162]: Happy to remove.

- 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 six~~four~~ existing projects:

- Develop effective management and treatment technologies to treat produced water via energy- and cost-efficient approaches for use within the oil and gas industry (2 projects)
- Develop advanced optimization software, big data tools, and machine-learning platforms to automate time-intensive tasks and perform high-computational analysis on produced water and relevant produced water management infrastructure data (2 projects)
- Develop advanced or novel membrane specific technologies for treatment of produced water (1 project)
- Developing methods ~~to~~ for chemical and biological characterization of produced water ~~e~~ to~~and~~ 1) extract rare earth elements or critical minerals ~~from produced~~ and 2) identify safe, beneficial reuse applications for treated produced water ~~water~~ (2~~1~~ projects)

4.4 REFERENCES

25 Pa. Code § 78.122(b)(6)(vi) and (vii). Well record and completion report.

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Commented [EK164]: 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 [ST165R164]: NETL: we need to ensure consistency in the depth and breadth of R&D sections across the chapters. Lets discuss.

Commented [HSAJ166R164]: R&D program - Highlight current research (as of July 31, 2023) The DOE has an active program addressing water impacts. Add 3 paragraphs from HH - 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.

Commented [EK167]: HH: Our program pivoted from this some time ago and we are no longer pursuing research in this area.

Commented [EK168R167]: 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

Commented [EK169R167]: HH: This does not include the 7-8 FOA awards which will be announced in the coming weeks - yes?

Commented [EK170R167]: @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

Commented [HH171R167]: @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

Commented [EK172R167]: OK, thanks for the clarification, Hichem. I'll bring this up tomorrow when I meet with @Sweeney, Amy and @Curry, Thomas.

Commented [HH173R167]: @Easley, Kevin Thanks, Kevin!

Commented [HH174]: 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 [LBD175]: Suggest update phrasing to more precise years as this reads as 2013-2023 to a current reader.

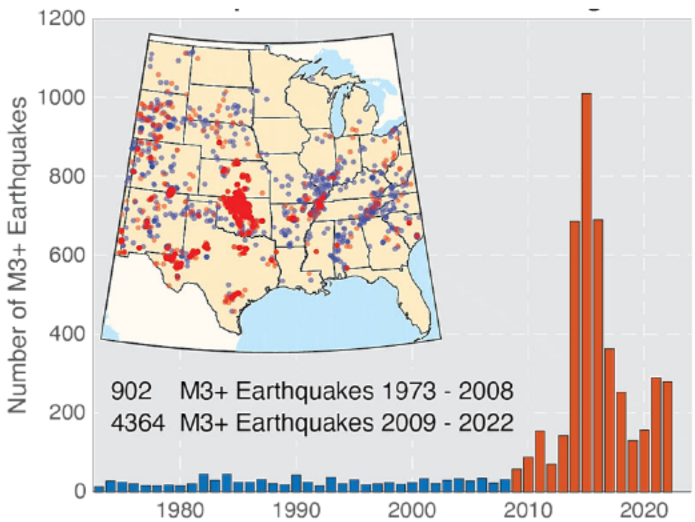
Commented [RW176R175]: Will do.

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

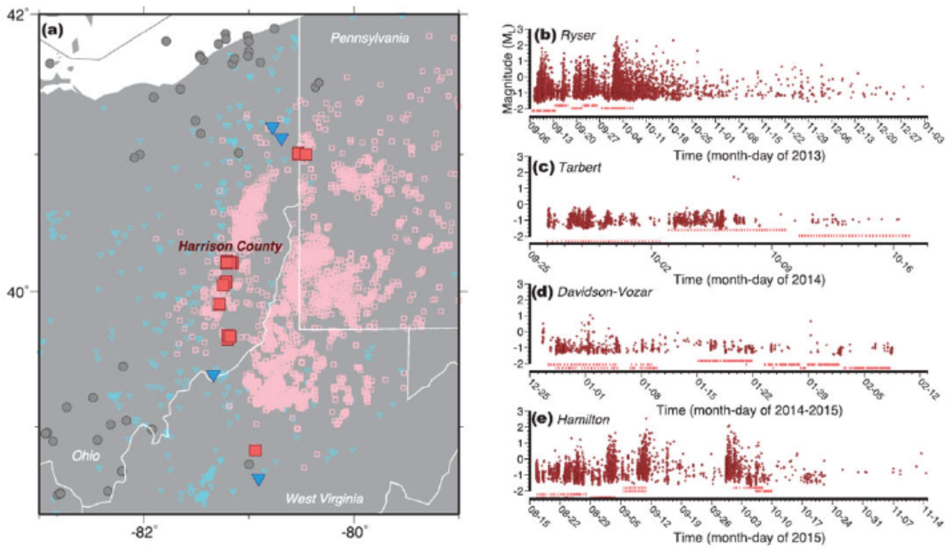
The Appalachian Basin is currently the largest natural gas producing area in the United States. The basin produced over 18 Mcf of natural gas a day (500 m^3/day) in 2019 (EIA, 2019a). The Marcellus and Point Pleasant Utica shale plays are both located in the Appalachian Basin and extend from New York 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 [EK177]: 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.

Commented [RW178R177]: I will double check.

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 ~~have~~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 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

[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.

Commented [EK179]: 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 [RW180R179]: Will check for consistency

Commented [EK181]: 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.

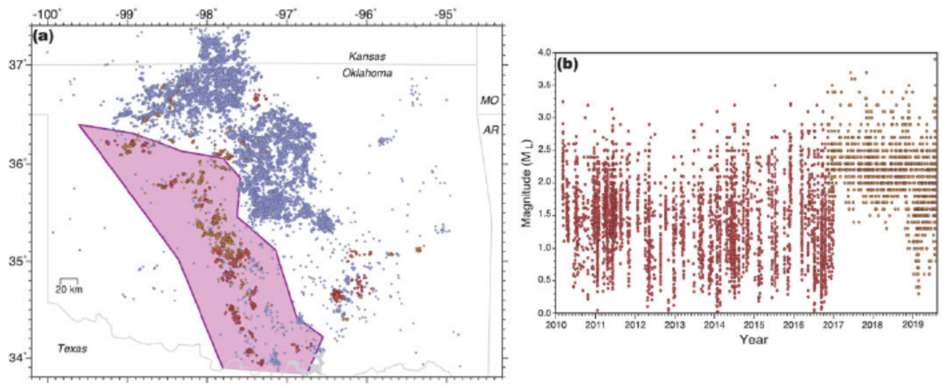
Commented [RW182R181]: It is incomplete. I believe there should have been a comma after the last word of the previous sentence.

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

Commented [EK183]: 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.

Commented [RW184R183]: Yes, corrected.

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~~ with 211 hydraulic fracturing well laterals.

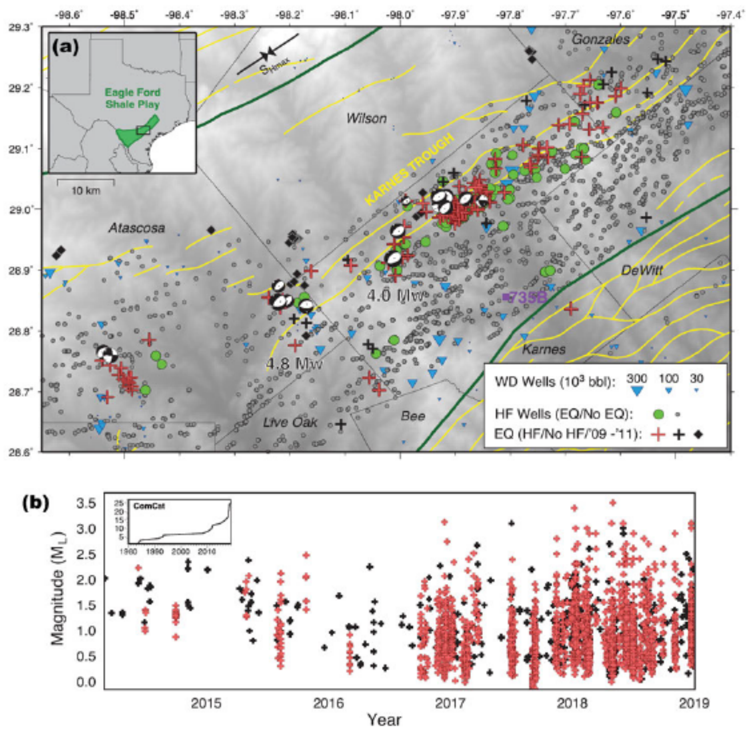
Commented [EK185]: NETL Team - 'will' (as written) or 'with' - or perhaps something else?

Commented [RW186R185]: with

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 events



Permission pending from Fasola et al. (2019)

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

State regulators have long been focused on identifying the precise location and magnitude of earthquakes and determining their cause. When~~If~~ earthquakes can be linked to wastewater injection, regulators respond~~could~~ by ordering~~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 created the~~s~~ Coordinating Council on Seismicity (2014)

Commented [HSAJ187]: 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.

Commented [EK188]: NETL Team - Changed 'If' to 'When' since the Addendum has already cited wastewater injection is one driver of induced seismicity.

Commented [RW189R188]: ok

- Oklahoma Corporation Commission directives reduce injection (2015)
- Oklahoma Geological Survey position paper published (2015)
- Secretary of Energy funded a~~s~~ $200,000 worth of 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 ~~t~~racking 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 Teas 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 [EK190]: NETL Team - to your knowledge, is this 2015 funding reference the most recent DOE / S-1 investment into induced seismicity projects?

Commented [HSAJ191]: Comes out.

Commented [HSAJ192]: Comes out.

Commented [LBD193]: Is any update available?

Commented [EK194]: NETL Team - it's unclear who the 'Applicants' are, what they are applying to, etc. Please provide additional details.

Commented [EK195R194]: Are we referring to operators in Texas applying for permits of one type or another RE: drilling, disposal, etc.? Please clarify.

Commented [LBD196]: 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 ~~of~~ 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 new~~d~~ or modify existing operations
- ML ≥ 2.5 – Temporary halt of well completions on lateral
- ML = 3.0+ – Well ~~C~~completion on pad suspended until an operator produces and secures approval of plan to mitigate risks and return to operational status~~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 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 [EK197]: 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 [EK198]: 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 [HSAJ199R198]: Refrain from fleshing out now so we can stay high level.

Commented [EK200]: 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 [EK201]: NETL Team - what is meant by / the consequences of this phrase: "full effect still unsure' when switching to smaller sieve sizes for proppant.

5.3 References

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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.

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 [HSAJ202]: 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.

Commented [EK203R202]: 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.

Commented [EK204]: 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.

Commented [RW205R204]: ok

transportation via transmission pipelines (transmission stage), and gas consumption as fuel~~the use~~ through combustion in gas-fired power plants (use stage).

Commented [EK206]: NETL Team - 'the use through' was somewhat clunky so I switeched up the text.

Commented [RW207R206]: ok

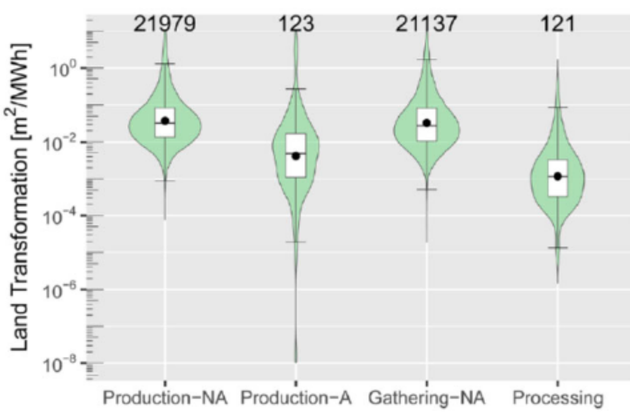
For the production stage, Dai et al. (2023) mapped land-use for 100,009 wells located at 75,915 different well pads. Among the 100,009 wells examined, 31,716 were co-located. In non-agricultural areas, results suggest vertical wells occupy ~4000 square meters (m^2) less land per site than horizontal-/directional-drilled 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 consumption~~use~~ of natural gas (Dai et al., 2023).

Commented [LBD208]: Suggest a few words explaining how, or possibly delete this sentence.

Commented [RW209R208]: I will look to expand the text from the source. If I cannot find specific examples, I will delete the 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

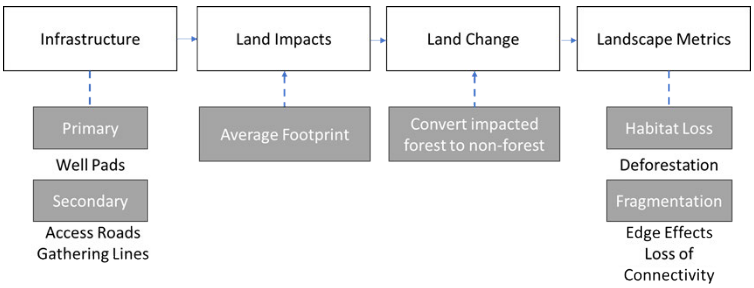
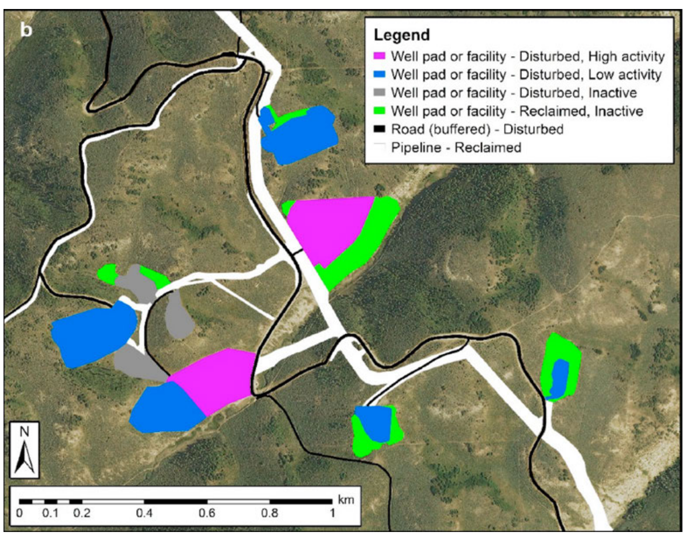


Exhibit 6-4 provides an example of energy infrastructure features digitized from 2013 National Agricultural Inventory Program satellite imagery overlaid with well locations reported in COGCC data. Each mapped feature (or portion thereof) was classified by type (well pad, facility, road, or pipeline) 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 (OECD) countries (Hafner et al., 2017; Boslett, 2021).

Commented [EK210]: Please add OECD to the Acronyms List.

Commented [RW211R210]: Will do

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).

Commented [LBD212]: This section should be alongside material in the first para of this section that addresses some human health effects.

Commented [RW213R212]: Will move it. Thank you!

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

Commented [LBD214]: Is "pollution" the right term? Air pollution from traffic is addressed above, so perhaps just "traffic"?

Commented [RW215R214]: ok

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 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

Commented [HSAJ216]: Bob will focus revisions here and move the regulations section up and condense as needed

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 (ESA) 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.

Commented [HSAJ217]: See comment in reference section of this chapter.

Commented [EK218]: 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.

Commented [EK219]: Please add ESA to the Acronym List.

Commented [RW220R219]: ok

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~~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~~research and development~~ or analysis with respect to land use, habitat fragmentation, or light, noise, or traffic pollution being conducted by DOE.

Commented [HSAJ221]: Comment for FE/HQ - Please advise if this is incorrect. We made every attempt to find information on current and ongoing R&D.

Commented [ST222R221]: If you are not sure it is accurate, we should not say it.

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Commented [HSAJ223]: If we have to cite then we can but we assume this may disappear when we move the regulations section up and move to more of an overview section.

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, contribute to perpetuating instances of energy, environmental, and social injustice. Conversely, if potential impacts to disadvantaged and frontline communities[o] 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 of net-zero emission transportation. Additional categories include affordable housing and "green" workforce development and training, as well as those focused on 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, missteps that have resulted in the unequal outcomes seen today. Under the aforementioned Justice40 initiative, the administration is ~~by~~ requiring that, moving forward, the success of projects ~~to~~ be measured according to how and for 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 information and potential guidance ~~as to how future research might be pursued~~ for project planning and implementation 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 projects 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~~

Commented [LBD224]: Suggest this section could possibly benefit from a tighter focus on the potential environmental impacts associated with unconventional natural gas.

Commented [HSAJ225R224]: Not necessarily just focused on the well-head now but the entire process from production to terminal. Beyond just unconventional too. Cut point is at midstream for impacts included(before gas is shipped away from the terminal).

Commented [HSAJ226]: Note to FE/HQ: Some comments made on the version returned to NETL on 7/28/23 have been deleted following Kevin's attempt to parse this section down. NETL believes the edits made by Kevin helped to significantly improve this chapter. We are open to further discussions on what may be missing still but have focused our efforts on addressing the comments from the email on 7/28 and comments that remain here.

Commented [LBD227]: 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.

Commented [HSAJ228]: Amanda - Note the lack of research that's been done but the need for it.

[o] 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).

~~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, 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 [RK229]: 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 [RK230R229]: If these recommendations are included then a title "Societal Considerations, Impacts, and Justice in UNG and LNG infrastructure development"

Commented [BO231R229]: 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.

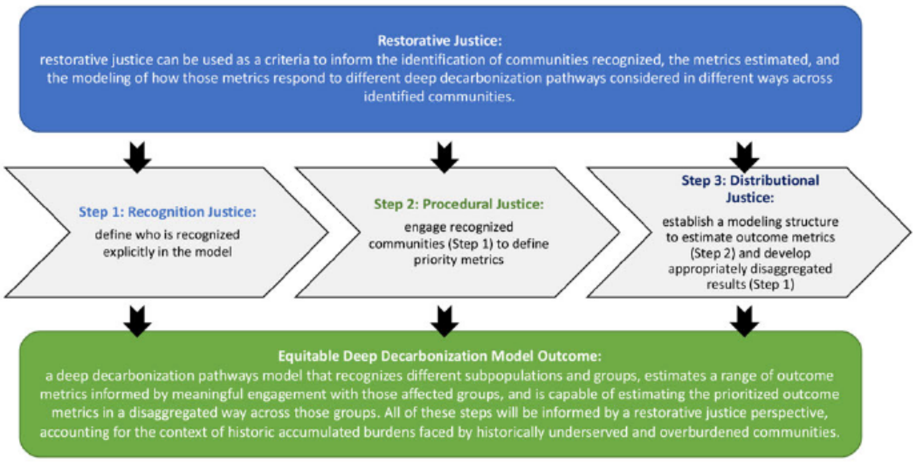
Commented [HSAJ232R229]: Share Kelli's notes with Kevin.

Commented [LBD233]: unclear

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 both the equitable and inequitable 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 advancing 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 individual~~these~~ communities who present the perspectives and opinions reflective of their respective 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 [DN234]: Justice40 Initiative | Department of Energy

Commented [DN235R234]: 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 [BO236R234]: 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 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 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 [RK237]: 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 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~~ plagued 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).

7.5 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

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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[p] (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~~

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

~~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).~~

~~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.~~

7.6 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 given the following ~~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 and services without some overarching set of rules to facilitate that outcome and a governance structure to underpin such requirements and drive ~~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, 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). 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 or possibly detract from 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 frameworks~~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 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 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).

7.7 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

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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).

7.8 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, and the greater sense of awareness and empathy and emphasis on inclusion engenders, 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 and a concerted push to net zero carbon emissions by 2050, opportunities~~the chance~~ to right those historical wrongs will present themselves~~itself~~.

DOE deploys a ~~the~~ Climate and Economic Justice Screening Tool to identify disadvantaged communities. To do so, the tool pulls in geographic information system data from~~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 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 identified and described as follows. ~~T~~Specifically, 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. And~~F~~ 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 desired 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.

Commented [EK242]: 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:
- 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

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~~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.~~

In closing, ~~T~~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. In addition,

~~T~~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: Francisco De La Chesnaye
Sent: Thu, 24 Aug 2023 19:52:47 +0000
To: Curry, Thomas; Sweeney, Amy
Cc: Yarlagadda, Brinda; Jamieson, Matthew B.; Scott Matthews; Daniel Hatchell; Iyer, Gokul; Binsted, Matthew; Whitman, Peter C; Riera, Jefferson; Skone, Timothy
Subject: [EXTERNAL] FECM LNG Export Draft Report
Attachments: DOE_FECM_LNG_Analysis_Report_DRAFT_24AUG23.docx
Importance: High

DRAFT/DELIBERATIVE/PRE-DECISIONAL

Dear Tom and Amy,

Ahead of tomorrow's meeting, please find attached the latest draft of the report titled "ENERGY, ECONOMIC, AND ENVIRONMENTAL ASSESSMENT of U.S. LNG EXPORTS". It contains the most current results under Task 1 and 2 from the PNNL and OnLocation teams. We have left room for the Task 3 LCA Analysis which can be incorporated as soon as it is completed.

Many thanks for all the hard work from the PNNL and OnLocation staff to get the project to this point (Gokul, pls forward as appropriate to others at PNNL).

We look forward to the review from FECM and to clearly laying out key next steps to finalize the full report.

Best, Paco

Francisco De La Chesnaye | **Vice President**
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ENERGY, ECONOMIC, AND ENVIRONMENTAL ASSESSMENT of U.S. LNG EXPORTS

WORKING DRAFT August 24, 2023

Prepared for:

Director, Division of Policy and Analysis
Office of Resource Sustainability
U.S. DEPARTMENT OF ENERGY | Fossil Energy and Carbon Management

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Acronyms and Abbreviations

AEO	Annual Energy Outlook
BECCS	Bioenergy with carbon capture and storage
Bcf	Billion cubic feet
BIL	Bipartisan Infrastructure Law
BP	British Petroleum
BTU	British Thermal Unit
CAFE	Corporate Average Fuel Economy
CCS	Carbon capture, and storage
CCUS	Carbon capture, utilization, and storage
CDR	Carbon dioxide removal
CH_4	Methane
CO2	Carbon dioxide
DAC	Direct air capture
DOE	Department of Energy
EIA	Energy Information Administration
EPA	Environmental Protection Agency
FECM	Fossil Energy and Carbon Management
GHG	Greenhouse gas
GCAM	Global Change Analysis Model
GNGM	Global Natural Gas Model
Gt	Gigaton
GWP	Global warming potential
HMM	Hydrogen Market Module
ITC	Investment tax credit
IRA	Inflation Reduction Act
LNG	Liquified natural gas
LULUCF	Land use, land use change, and forestry

NERA	National Economic Research Associate
NEMS	National Energy Modeling System
NGA	Natural Gas Act
NGP	Natural gas processing
NHTSA	National Highway Transit Safety Administration
NREL	National Renewable Energy Laboratory
N2O	Nitrous oxide
Mcf	Million cubic feet
MMT	Million metric Tons
PTC	Production tax credit
S&P	Standard & Poor's
Tcf	Trillion cubic feet

I. EXECUTIVE SUMMARY

The Department of Energy (DOE) is responsible for authorizing exports of natural gas, including liquified natural gas (LNG), to foreign countries pursuant to section 3 of the Natural Gas Act (NGA), 15 U.S.C. 717b. For Authorizations relating to those countries which the United States does not have a free trade agreement (FTA), section 3(a) of the NGA requires DOE to grant a permit to export domestically produced natural gas unless it finds that such action is not consistent with the public interest. To inform its Public Interest determination, since 2012, the Office of Fossil Energy and Carbon Management (DOE-FECM) and its predecessor, the Office of Fossil Energy, have commissioned five studies on the effects of increased LNG exports on the U.S. economy and energy markets. This updated study, like the previous ones, serves as an input to be considered in the evaluation of applications to export LNG from the United States under Section 3 of the NGA.

The purpose of this study is to examine the potential global and U.S. energy system and greenhouse gas (GHG) emissions implications of a wide range of economic levels of U.S. LNG exports. The study comprises of three tasks: 1) **a Global Analysis** to explore a wide range of scenarios of U.S. LNG exports under alternative assumptions about future socioeconomic growth, regional preferences for domestically produced natural gas, pace of technological change in competing technologies (e.g. renewables), and countries' announced GHG emissions pledges and policies; 2) **a U.S. Domestic Analysis** of the implications of the various U.S. LNG export levels derived from the global analysis above for the supply and demand of natural gas within the U.S. and the U.S. economy; and 3) **a Life Cycle Analysis** to examine the lifecycle emissions implications of the various levels of U.S. LNG exports derived from the domestic and global analyses in tasks 1 and 2.

As part of the **Global Analysis**, we explore seven scenarios that span a range of plausible U.S. LNG export outcomes by 2050 using the Pacific Northwest National Laboratory's Global Change Analysis Model (GCAM) (Table ES 1). GCAM is an open-source model of the global energy, economy, agriculture, land-use, water, and climate systems with regional detail in 32 geopolitical regions. This includes major economies as single-country regions (e.g., U.S., Canada, China, India, Russia). The seven scenarios explored in this study are as follows:

> ***S1*: Reference Capacity** (Reference scenario in which U.S. LNG exports follow the U.S. Energy Information Administration's (EIA's) 2023 Annual Energy Outlook (AEO))
>
> ***S2*: Market Response** (economic solution for U.S. LNG exports)
>
> ***S3*: High Global Demand** (economic solution for U.S. LNG exports, higher population growth outside of the U.S.)
>
> ***S4*: Regional Import Limits** (economic solution for U.S. LNG exports, global focus on maximizing local energy sources)
>
> ***S5*: Low-cost Renewables** (economic solution for U.S. LNG exports, low costs for renewable energy)

> ***S6*: Energy Transition (Ref Cap)** (AEO 2023 reference case trajectory for U.S. LNG exports, countries achieve emissions pledges and pursue ambitious GHG mitigation policies consistent with limiting global warming to 1.5°C, U.S. emissions to net-zero by 2050)
>
> ***S7*: Energy Transition (Mark Resp)** (economic solution for U.S. LNG exports, countries achieve emissions pledges and pursue ambitious GHG mitigation policies consistent with limiting global warming to 1.5°C, U.S. emissions to net-zero by 2050)

All of the above scenarios include the 2022 Inflation Reduction Act in the U.S., and current emission policies in the rest of the world. The scenarios also include a constraint on Russian exports.

The **U.S. domestic analysis** is conducted using the National Energy Modeling System (NEMS). U.S. LNG exports (for all scenarios) and CO_2 emissions (in scenarios *S6* and *S7*) from NEMS are harmonized to values from GCAM. NEMS is then used to explore the implications of the seven global scenarios for domestic gas prices, energy system, and macro-economy within the U.S.

Finally, a **life cycle analysis** is conducted by assessing the results provided from the domestic and global analyses and comparing them to previously completed studies of the domestic natural gas life cycle and of LNG delivered around the world. NEMS results are inspected to assess whether the domestic supply of natural gas from regional extraction is expected to have a significantly different impact than as previously modeled in 2020. GCAM results are assessed and compared to existing DOE life cycle studies of natural gas and aligned to have the same GHG intensity for the purposes of consistency.

Four key insights emerge from this study:

> First, across all modeled scenarios, U.S. LNG exports continue to grow beyond existing and planned nameplate capacity (18.7 Bcf/day) through 2050 resulting in wide range of outcomes (23-47 Bcf/day, Figure ES-1). The range of U.S. LNG exports from this study is consistent with the U.S. EIA's 2023 Annual Energy Outlook (AEO2023, 15-48 Bcf/day).
>
> Second, compared to a scenario in which U.S. LNG exports follow the Reference case from the AEO2023 (*S1*, growing to 27.3 Bcf/day by 2050), a scenario that assumes economically driven LNG export levels (*S2*) results in significant growth in U.S. LNG exports to 47 Bcf/day by 2050. The availability of additional U.S. gas at competitive prices in the global gas market in the latter scenario (*S2*) results in a reduction in production, reduction in LNG exports, increase in LNG imports, and reduction in pipeline trade outside of the U.S. However, global gas consumption increases only slightly as the availability of additional U.S. gas does not materially affect the competitiveness of gas relative to other fuels globally. Instead, it only results in a shift in the regional composition of gas production and trade. Consequently, global and U.S. primary energy consumption and GHG emissions also do not change much. The higher U.S. LNG exports also results in higher domestic gas prices (2050 gas prices increase from \$3.60/MMBtu in *S1* to \$4.75/MMBtu in *S2*).
>
> Third, global and U.S. GHG emissions do not change significantly across scenarios *S1* through *S5* even though these scenarios vary widely in terms of U.S. LNG export outcomes. Emissions in scenarios *S6* and *S7* are lower than the remaining scenarios as they are constrained to lower values by design.

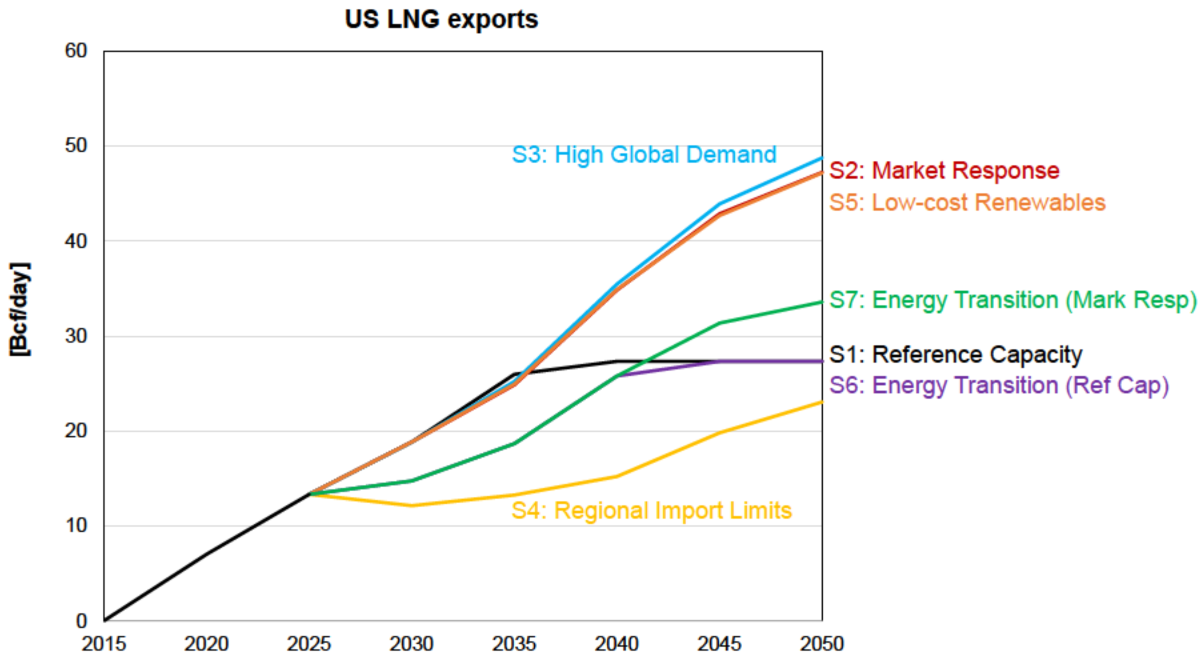

Figure ES-1. U.S. LNG exports across the scenarios explored in this study

Finally, scenarios *S6* and *S7* – in which countries are assumed to achieve their emissions pledges and pursue ambitious GHG mitigation policies consistent with limiting global warming to 1.5°C – are characterized by a global transition resulting in a reduction in gas, coal, and oil consumption without carbon capture, utilization, and storage (CCUS); increased deployment of gas, coal and biomass with CCUS, and renewables; increased deployment of carbon dioxide removal strategies including bioenergy in combination with CCUS, direct air capture, and afforestation; and a net reduction in energy consumption. While in scenario *S6*, U.S. LNG exports grow to 27.34 Bcf/day following the AEO2023 Reference case trajectory (by design), *S7* assumes economically driven outcomes resulting in U.S. LNG exports to grow to 34 Bcf/day by 2050. The higher growth in U.S. LNG exports in *S7* compared to *S6* is driven by increased demand for gas with CCUS in the power and industrial sectors. Similar to the comparison between *S1* and *S2*, the availability of additional U.S. LNG in *S7* in the global gas market results in a very small increase in gas consumption, reduction in production, reduction in LNG exports, increase in LNG imports, and reduction in pipeline trade in the rest of the world compared to *S6*. Furthermore, with the higher U.S. LNG exports in *S7* compared to *S6*, by 2050 gas prices are essentially unchanged within modeling tolerance, reaching $5.90/MMBtu in *S6* and $5.77/MMBtu in *S7*.

[From a life cycle perspective, the changes in U.S. regional natural gas production by 2050 are not expected to have a significantly different global warming potential (GWP) intensity than that of 2020.]

II. Background on LNG Export Studies Commissioned by Department of Energy

Since 2012, the Office of Fossil Energy and Carbon Management and its predecessor, the Office of Fossil Energy have commissioned six studies on the effects of increased LNG exports on the U.S. economy and energy markets. The five previous studies of the impact of LNG exports are listed in Table 1.

Table 1. Previous Studies

Report Name	Organization	Short Name
Effect of Increased Natural Gas Exports on Domestic Energy Markets[1]	EIA	EIA 2012
Effect of Increased Natural Gas Exports on Domestic Energy Markets[2]	NERA	NERA 2012
Effect of Increased Levels of Liquefied Natural Gas Exports on U.S. Energy Market[3]	EIA	EIA 2014
The Macroeconomic Impact of Increasing U.S. LNG Exports[4]	Baker Institute/ Oxford Economics	Baker 2018
Macroeconomic Outcomes of Market Determined Levels of U.S. LNG Exports[5]	NERA	NERA 2018

The EIA 2012 study examined four different levels of exports across four domestic natural gas supply scenarios for a total of sixteen scenarios. Exports ranged from 6 to 12 Bcf/day with varying trajectories. The four scenarios were: AEO2011 Reference, High Shale Estimated Ultimate Recovery (EUR), the Low Shale EUR, and High Economic Growth. Key results demonstrate that natural gas markets balanced the increased exports through increased supply and prices and a reduction in demand for power generation and in the other sectors. However, this report did not address microeconomic impacts.

The NERA 2012 report used NERA's Global Natural Gas Model ("GNGM") and NewERA energy-economy model to look at the domestic economic effects of LNG exports. Building upon the EIA 2012 study, the NERA 2012 report examined sixteen scenarios from the earlier study using different assumptions on the natural gas supply and demand. The report additionally included scenarios examining the global demand for U.S. LNG exports and the macro-economic impact of increased LNG exports on the domestic economy.

[1] U.S. EIA. (2012). Effects of Increased Natural Gas Exports on Domestic Energy Markets. Available at: https://energy.gov/sites/prod/files/2013/04/f0/fe_eia_lng.pdf

[2] NERA Economic Consulting. (2012). Macroeconomic Impacts of LNG Exports from the United States. Available at: https://energy.gov/sites/prod/files/2013/04/f0/nera_lng_report.pdf

[3] U.S. EIA. (2014). Effect of Increased Levels of Liquefied Natural Gas Exports on U.S. Energy Markets. Available at: https://www.eia.gov/analysis/requests/fe/pdf/lng.pdf

[4] Cooper, A., Kleiman, M., Livermore, S., & Medlock III, K. B. (2015). The Macroeconomic Impact of Increasing US LNG Exports. Available at: https://energy.gov/sites/prod/files/2015/12/f27/20151113_macro_impact_of_lng_exports_0.pdf

[5] NERA Economic Consulting. (2018). Macroeconomic Outcomes of Market Determined Levels of U.S. LNG Exports. Available at: https://www.energy.gov/sites/prod/files/2018/06/f52/Macroeconomic%20LNG%20Export%20Study%202018.pdf

The EIA 2014 study included updated export scenarios from 12 to 20 Bcf/day and domestic natural gas from AEO2014: the Low and High Oil and Gas Resource scenarios, High Economic Growth, and Accelerated Coal and Nuclear Retirements. Increased exports led to increased production and prices relative to their respective base scenario, though also higher primary energy consumption and energy-related CO_2 emissions.

The Baker 2015 study examined U.S. LNG exports of 12 and 20 Bcf/day. Two models were used: an international natural gas model (from the Baker institute) and a global economic model from Oxford Economics. This study determined the international conditions required to provide a market for over 20 Bcf/day of LNG exports and examined in the impact on the U.S. economy of scenarios with 12 and 20 Bcf/day of LNG exports and with low gas resource recovery, high gas resource recovery and high demand.

The NERA 2018 again used NERA's Global Natural Gas Model and the NewERA energy-economy model to look at the domestic economic effects of LNG exports. LNG exports were endogenously determined for each scenario. The study included 54 different scenarios capturing a broad range of international gas supply and demand conditions, and probabilities on the likelihood of each of the 54 export scenarios. In general, high levels of LNG exports corresponded to high oil and gas supply but higher prices. Since approximately 80% of the exports resulted from increased production rather than decreased demand, the general economic impact was positive across the scenarios. The report concluded that the impact on energy sensitive industries was very small while increased investment raised GDP.

III. Introduction

A. Project Background

The Department of Energy (DOE) is responsible for authorizing exports of natural gas, including LNG, to foreign countries pursuant to section 3 of the Natural Gas Act (NGA), 15 U.S.C. 717b. Authorizations for those countries which the United States does not have a free trade agreement (FTA) requiring national treatment for trade in natural gas, and with which trade is not prohibited by U.S., are governed by Section 3(a). For such applications, NGA section 3(a) provides that DOE provide such authorization for the exportation of natural gas unless DOE determines that doing so ‘‘will not be consistent with the public interest.’’ [6]

DOE has identified a range of factors that it evaluates when reviewing an application for export authorization. Specifically, DOE's review of export applications has focused on: "(i) the domestic need for the natural gas proposed to be exported, (ii) whether the proposed exports pose a threat to the security of domestic natural gas supplies, (iii) whether the arrangement is consistent with DOE's policy of promoting market competition, and (iv) any other factors bearing on the public interest as determined by DOE, such as international and environmental impacts."[7]

To inform its Public Interest determination, since 2012, the Office of Fossil Energy and Carbon Management and its predecessor, the Office of Fossil Energy, commissioned five studies on the effects of increased LNG exports on the U.S. economy and energy markets. The studies examined impacts on the domestic natural gas market and economic impact of increasing demand including exports.

This updated study, like the those previous, is intended to serve as an input to be considered in the evaluation of applications to export LNG from the United States under Section 3 of the Natural Gas Act, which requires DOE to grant a permit to export domestically produced natural gas unless it finds that such action is not consistent with the public interest.

DOE/FECM commissioned OnLocation, Pacific Northwest National Laboratory and the National Energy Technology Laboratory (ONL/PNNL/NETL) to assess the economic level of U.S. LNG exports and across seven scenarios representing a broad range of economic, environmental, and political scenario, along with changes to global greenhouse gas emissions at differing levels of U.S. LNG exports. U.S. LNG exports were found using a global equilibrium model and were then input into the domestic model to examine the market effects of increased LNG exports, including natural gas price and consumption across sectors and changes in U.S. greenhouse gas emissions. Finally, the incumbent lifecycle analysis of U.S. LNG exports was expanded through to incorporate market effects from the results of this study.

B. Purpose of Study

Since the NERA 2018 report was published, several events have altered the explicit and implicit assumptions underpinning the global and U.S. natural gas markets. These include i) the issuance of additional LNG export authorizations, ii) the Ukrainian-Russia war, iii) global and U.S. greenhouse gas

[6] Natural Gas Act. 15 U.S.C. 717b.

[7] Order Amending Long-Term Authorization to Export Liquefied Natural Gas to Non-Free Trade Agreement Nations at 43, Magnolia LLC, Docket 13-132-LNG (April 2022).

policy developments, iv) technological change in production, transmission, storage, and end-use of natural gas, iv) and the passage of significant energy-related legislation (Bipartisan Infrastructure Law (BIL) and Inflation Reduction Act (IRA)).The purpose of this study is to determine the economic level of U.S. LNG exports across a wide range of global, and show the potential energy, macroeconomic greenhouse gas effects of LNG exports at those levels. The scope of the project required conducting three distinct but inter-related analyses: a global analysis of LNG exports, a domestic analysis of the impact of LNG exports on the supply and demand of natural gas and on the U.S. economy, and a lifecycle analysis of LNG exports informed by the impact on the global energy system of various levels of LNG exports.

This report updates previous analytical work in line with current laws and regulations, as well as economic and technology conditions using newly derived scenarios. The seven scenarios chosen are:

> ***S1*: Reference Capacity** (Reference scenario in which U.S. LNG exports follow the U.S. Energy Information Administration's 2023 Annual Energy Outlook (AEO))
>
> ***S2*: Market Response** (Economic solution for LNG exports)
>
> ***S3*: High Global Demand** (Economic solution for LNG exports, higher population growth outside of the U.S.)
>
> ***S4*: Regional Import Limits** (Economic solution for LNG exports, global focus on maximizing local energy sources)
>
> ***S5*: Low-cost Renewables** (Economic solution for LNG exports, low costs for variable renewable energy technologies)
>
> ***S6*: Energy Transition (Ref Cap)** (AEO 2023 reference case trajectory for U.S. LNG exports, countries achieve emissions pledges and pursue ambitious GHG mitigation policies consistent with limiting global warming to 1.5°C, U.S. emissions to net-zero by 2050)
>
> ***S7*: Energy Transition (Mark Resp)** (economic solution for LNG exports, countries achieve emissions pledges and pursue ambitious GHG mitigation policies consistent with limiting global warming to 1.5°C, U.S. emissions to net-zero by 2050)

These will be described in more detail in Section I.A"

C. Organization of the Report

The introduction presents the background and purpose of the study. The study methodology, scenario design, and key assumptions section introduces the scenarios and the version of the NEMS models used for the analysis. The section on energy and climate mitigation technology results gives primary energy changes between scenarios and discusses the impact of carbon removal technologies on the Energy Transition scenarios. The natural gas market results include the core impact on the natural gas markets across the scenarios, including price and consumption of natural gas across sectors. The U.S. macro-economic outcomes show some key impacts of LNG exports, such as sectoral prices, investment, and consumer spending. Finally, the section on greenhouse gas outcomes shows the impact on domestic energy-related CO_2 emissions across the scenarios.

IV. Scenarios, Methodology, and Key Assumptions

A. GCAM Model and Global Scenarios Design

The Global Change Analysis Model (GCAM) is an open-source model developed and maintained at the Pacific Northwest National Laboratory's Joint Global Change Research Institute. This study uses GCAM v 6 and is available in a public repository. The full documentation of the model is available at the GCAM documentation page (http://jgcri.github.io/gcam-doc/), and the description here and in the appendix is a summary of the online documentation.

GCAM includes representations of five systems: economy, energy, agriculture and land use, water, and climate. These systems are represented in 32 geopolitical regions across, 384 land subregions, and 235 water basins across the globe. GCAM operates in 5-year time-steps from 2015 (calibration year) to 2100 by solving for the equilibrium prices and quantities of various energy, agricultural, water, land-use, and greenhouse gas (GHG) markets in each time period and in each region. Outcomes of GCAM are driven by exogenous assumptions about population growth, labor participation rates and labor productivity in the 32 geo-political regions, along with representations of resources, technologies, and policy. GCAM tracks emissions of twenty-four gases, including GHGs, short-lived species, and ozone precursors, endogenously based on the resulting energy, agriculture, and land use systems. GCAM's energy system contains representations of fossil resources (coal, oil, gas), uranium, and renewable sources (wind, solar, geothermal, hydro, biomass, and traditional biomass) along with processes that transform these resources to final energy carriers (electricity generation, refining, hydrogen production, gas processing, and district heat), which are ultimately used to deliver goods and services demanded by end use sectors (residential buildings, commercial buildings, transportation, and industry). Natural gas competes for share with other fuels in the electricity generation sector, and with other fuels and electricity in the buildings, industrial, and transportation sectors. Each of the sectors in GCAM includes technological detail. In every sector within GCAM, individual technologies compete for market share based on the levelized cost of a technology (see appendix for more details). The version of GCAM used in this study also includes a representation of three carbon dioxide removal strategies that are deployed in scenarios with emissions policies, namely, direct air capture (DAC), bioenergy in combination with carbon capture and storage, and afforestation (see appendix for more details).

GCAM includes a representation of gas trade that creates price-based competition between domestic gas and imported gas. This representation introduces realistic inertia in the evolution of trade from current patterns. Gas can be imported as liquefied natural gas (LNG) or through pipelines. Traded LNG is represented as a single global market. All producers of natural gas can export to a global LNG pool from which importers can import. While the price of domestic gas is based on extraction costs that are derived from long-term regional resource supply curves, the price of imported LNG includes costs for shipping, liquefaction, and regasification in addition to extraction costs. Traded pipeline gas is represented in six regional markets (North America, Latin America, Europe, Russia+, Africa and Middle East, and Asia-Pacific). Exporters of pipeline gas export to one of the six regional pipeline blocs from which importers can import. Inter-pipeline bloc trade can also occur. For example, GCAM's EU-12 region exports only to the "Europe" pipeline bloc but can import from the "Russia" pipeline bloc and the "Middle East and Africa" pipeline bloc in addition to the "Europe" pipeline bloc. These pipeline trade relationships are based on existing relationships. The price of imported pipeline gas includes the costs of building and operating pipeline infrastructure in addition to resource extraction costs. Gross exports and imports of LNG and pipeline gas are calibrated to historical data in GCAM's historical calibration year (2015). In a future model period, trade volumes evolve from historical patterns depending on future demands and prices. For the purposes of this project, historical gas producer prices in the U.S. are calibrated to the Henry Hub prices from the Energy Information Administration (EIA) and in Canada, they are calibrated to Alberta marker prices from the BP Statistical Review.[8] For the rest of the world, gas producer prices in each GCAM region are based on the cost, insurance, and freight (CIF) prices from S&P. In a future model period, as demand changes, the change in regional producer prices from the historical calibrated values are calculated endogenously using regional supply curves that represent increasing cost of extraction as cumulative extraction increases. GCAM also tracks turnover of trade infrastructure (e.g., liquefaction and regasification units, and pipelines). Trade infrastructure can either retire naturally or in response to economic changes (e.g., those driven by an emissions policy).

Using GCAM, we explore seven scenarios that span a range of plausible U.S. LNG export outcomes by 2050 (Table 2). All of our scenarios include the 2022 Inflation Reduction Act in the U.S., and current emission policies in the rest of the world. The scenarios also include a constraint on Russian exports such that Russian pipeline exports to EU are decline until 2035 and then remain flat, and LNG exports from Russia are flat, and Russian pipeline exports to the east (e.g., to China) continue to increase. Our scenarios include planned and existing LNG capacity additions in major economies including the U.S. Middle East, Australia, Canada, Southeast Asia, and Africa. Socioeconomic (population and economic growth) assumptions for the U.S. are harmonized to the AEO-2023 Reference case.

The first scenario is a reference scenario, namely, *S1: Reference Capacity*. This scenario assumes that the U.S. LNG exports follow the trajectory from the Reference case of the U.S. Energy Information Administration's (EIA's) 2023 Annual Energy Outlook (AEO2023) projections to grow to 27.34 Bcf/day in 2050. The AEO2023 Reference Capacity incorporates U.S. LNG export projects that are either operating or under construction as of August 2022 and then adds capacity based on the cost-competitiveness of exporting U.S. LNG to the international market including an annual capacity build- constraint. More specifically, LNG export facilities have a combined operating capacity of 10.3 Bcf/d with an additional 4.5 Bcf/d of operating capacity under construction. An additional 12.6 Bcf/d of operating capacity is assumed to be constructed in response to international demand for U.S. LNG. The second scenario, *S2: Market Response*, assumes economically driven, market-based outcomes, including for U.S. LNG exports. The third scenario, *S3: High Global Demand*, includes the same assumptions as in scenario *S2*, but assumes a higher population growth in regions outside of the U.S. consistent with the Shared Socioeconomic Pathways – 3.[9] This results in ~1 billion more people globally in *S3* by 2050 compared to *S1 and S2* and explores the effects of higher U.S. LNG exports driven by higher demand for all energy sources (including natural gas) compared to *S2*. The fourth scenario, *S4. Regional Import Limits* includes the same assumptions as in *S2*, but with constraints on natural gas imports globally to maximize the use of domestically produced gas across the world (Table A-1). This scenario explores the effects of lower U.S. and global LNG exports driven by global energy security concerns and trade limitations. The fifth

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[8] BP (2022). bp Statistical Review of World Energy. 71st edition. Available at: https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/statistical-review/bp-stats-review-2022-full-report.pdf

[9] Samir, K. C., & Lutz, W. (2017). The human core of the shared socioeconomic pathways: Population scenarios by age, sex and level of education for all countries to 2100. Global Environmental Change, 42, 181-192.

scenario, *S5: Low-cost Renewables*, includes the same assumptions as in *S2*, but assumes lower capital costs for renewable energy technologies such as onshore and offshore wind, solar photovoltaic, concentrated solar power, and geothermal. This scenario explores the effects of faster technological improvements in competing technologies. While technology cost assumptions in other scenarios are consistent with NREL's Annual Technology Baseline (ATB) "Medium" assumptions, capital cost assumptions for onshore and offshore wind, solar photovoltaic, concentrated solar power, and geothermal technologies under *S5* are based on the "Low" assumptions. The last two scenarios, namely, *S6: Energy Transition (Ref Cap)*, and *S7: Energy Transition (Mark Resp)*, assume an emission pathway that is consistent with a global temperature change of 1.5°C by 2100 derived from published peer-reviewed literature.[10,11,12] Both of these scenarios assume that countries achieve their emission pledges as made during the 21st Conference of Parties of the United Nations Framework on Climate Change held in Glasgow. The pledges include nationally determined contributions that outline emission reduction plans through 2030, long-term strategies, and net-zero pledges that outline plans through the mid-century. The U.S. is assumed to reduce economy-wide greenhouse gas emissions by 51% in 2030 and 100% by 2050. Countries without pledges are assumed to follow an emissions pathway defined by a minimum decarbonization rate of 8% that is indicative of strong mitigation policies and significant departure from historically observed decarbonization rates.[10,11,12] The scenarios assume that countries achieve their pledges within their geographic boundaries without trading emissions. *S6* differs from *S7* in that it also limits U.S. LNG exports to the values from the AEO2023 Reference case. A key distinction between scenarios *S1* and *S6* is that while the former assumes the U.S. LNG exports to follow the AEO2023 Reference case exactly, the latter assumes the values from the AEO2023 Reference case to be an upper bound. Nevertheless, scenario *S6* enables comparisons with *S1*, and scenario *S7* enables comparisons with *S2*.

Table 2. Scenario Descriptions

Scenario	Description	U.S. LNG Export Volumes (Bcf/d)
***S1*: Reference Capacity**	Reference scenario that follows EIA's 2023 Annual Energy Outlook (AEO) including U.S. policy assumptions (including the 2022 Inflation Reduction Act). Assumes existing policies and measures, globally.	Grows to 27.34 Bcf/d by 2050
***S2*: Market Response**	Assumes policies consistent with *S1* and an economic solution for LNG exports.	GCAM Market Response

[10] Fawcett, A. A., et al. (2015). Can Paris pledges avert severe climate change?. Science, 350(6265), 1168-1169.
[11] Ou, Y., Iyer, G., et al. (2021). Can updated climate pledges limit warming well below 2°C?. Science, 374(6568), 693-695.
[12] Iyer, G., Ou, Y., et al. (2022). Ratcheting of climate pledges needed to limit peak global warming. Nature Climate Change, 12(12), 1129-1135.

***S3*: High Global Demand**	Same assumptions as *S2*, economic solution for LNG exports, but higher assumed population growth outside of the U.S.	
***S4*: Regional Import Limits**	Same assumptions as *S2*, economic solution for LNG exports, but constraints on importing and exporting natural gas with a global focus to maximize use of domestic gas.	
***S5*: Low-cost Renewables**	Same assumptions as *S2*, economic solution for LNG exports, but lower capital costs for renewable energy technologies.	
***S6*: Energy Transition (Ref Cap)**	Assumes an emissions pathway consistent with a global temperature change of 1.5°C by end of century. Countries' emissions are constrained to announced GHG pledges, including the U.S. following a path to net-zero GHG emissions by 2050. NEMS follows CO_2 emissions constraint from GCAM. U.S. LNG exports are limited to the values from the AEO 2023 Reference scenario.	Grows to 27.34 Bcf/d by 2050
***S7*: Energy Transition (Mark Resp)**	Same emissions pathway assumptions as *S6* but economic solution for LNG exports.	GCAM Market Response

B. NEMS Models and Analysis Methodology

1. AEO23-NEMS

NEMS is an energy-economic model of the U.S. It projects supply, demand conversion, imports, and exports of major energy commodities, drivers such as macroeconomic conditions, world energy markets, technology choices and costs, resource availability, and demographics. The NEMS model includes both cost minimization representative of competitive markets and behavioral representations of the energy market.

NEMS is a modular energy system model. There are four supply modules, covering oil, natural gas, coal, and renewables. There are two conversion modules, converting primary fuels into electricity and petroleum and other liquids into liquid fuel products respectively. There are four demand modules, covering the residential, commercial, industrial, and transportation sectors. Other modules include the macroeconomic module, emissions policy modules, and an integrating module that synthesizes the output across all other modules. NEMS solves iteratively to reach a general market equilibrium across the energy economy.

The EIA provides an archive of the NEMS model with source code and input sufficient to reproduce the reference and side cases comprising the Annual Energy Outlook. AEO23-NEMS is OnLocation's version of the NEMS model, modified to allow exogenous input of U.S. LNG exports. The AEO2023 reference scenario has a macroeconomic growth assumption of 1.9% average growth per year. The model has the EIA's interpretation of the IRA which includes most major provisions of the policy. The model does not include carbon capture at industrial sites (ethanol, hydrogen, NGP, cement) or direct air capture. Therefore, the IRA 45Q credit for DAC is not included. Similarly, IRA 45V hydrogen credits are also not represented in the AEO23 version of NEMS as it does not have the hydrogen module.

2. FECM-NEMS

FECM-NEMS is based on the AEO22 version of NEMS and uses low economic growth assumptions. It assumes a real GDP average growth of 1.8% per year to 2050. The model has been enhanced to represent several CO_2 mitigation technologies, including carbon capture and sequestration (CCS), direct air capture (DAC), bioenergy with CCS (BECCS) and the hydrogen market module (HMM). Industrial carbon capture is found in the liquid fuels module which allows the construction of new hydrogen and ethanol facilities with CCS. It also allows for existing hydrogen, ethanol, and natural gas processing plants to retrofit CCS capability. The cement industry has also been enhanced to include CCS opportunities. Industries have the option to send captured CO_2 to an enhanced oil recovery market or store it in saline aquifers.

The HMM is integrated into NEMS to produce hydrogen via conventional, and low carbon processes. The hydrogen production technologies available in the HMM include steam methane reformation (SMR), SMR with CCS, biomass gasification with CCS and electrolysis.

FECM-NEMS models the Inflation Reduction Act based on FECM's interpretation of the policy. It includes major IRA energy related provisions including but not limited to, the extension of 45Q CO_2 sequestration credits, clean vehicle tax credits, energy efficient home tax credits and rebate programs, clean energy PTC and ITC, zero emission nuclear credits, and hydrogen tax credits. Additional modelling updates include provisions from the Bipartisan Infrastructure Law (BIL) such as funding for carbon capture demos and CO2 transportation and storage infrastructure, updated EPA/NHTSA CAFE standards.

Given the carbon capture opportunities and the net negative carbon technologies such as DAC and BECCS, the FECM-NEMS model allows the economy to achieve net-zero carbon emission scenario.

3. Harmonizing GCAM and NEMS

While GCAM and NEMS are distinct models, coordination between them is necessary to maintain consistency and tie the NEMS results back to the global LNG market forecast. Harmonization efforts are taken to ensure that LNG exports (for all scenarios) and CO_2 emissions (in the net-zero scenarios) are consistent across the two models.

The EIA's AEO23 reference case is selected to define *S1*. In AEO23-NEMS, the AEO23 reference case solution file is adopted for all variables. LNG exports from the AEO23 reference case are then used as exogenous inputs into the GCAM model, in place of endogenous estimates. For *S2* through *S7*, the process is reversed: the scenarios were first run in the GCAM model, from which endogenously calculated LNG export curves were taken and input exogenously into AEO23-NEMS. The endogenous algorithm used by NEMS to calculate LNG exports was turned off for these scenarios. Since a key driver of LNG exports is the differential between domestic and world natural gas prices, domestic natural gas prices from NEMS were then compared with North American prices in GCAM. In all scenarios except *S5*, technology and resource were aligned between GCAM and the reference scenario AEO2022. In *S5*, both models adjusted power generation technology assumptions consistent with the AEO2022 Low Renewable Cost scenario from the AEO.

For *S6* and *S7*, the net-zero scenarios were first run in the GCAM model, which uses global interactions and feedback to model U.S. LNG under a criteria of net-zero GHG by 2050. As part of the modeling process, GCAM generates a set of emissions curves that list quantities of GHG emissions of various sectors and gases (CO_2, CH_4, N_2O, F), as well as emissions and removals from land use, land-use change, and forestry (LULUCF). These curves are outputs of the model, although the sum of individual emissions is defined in the model inputs such that they reach or exceed a net-zero target in 2050. The output emissions curves from GCAM were used to specify how the net-zero scenario is implemented in FECM-NEMS.

The values of CO_2 emissions from the energy sector were taken from the GCAM output and used explicitly as the carbon cap in FECM-NEMS to model the net-zero scenarios. The carbon cap curve (used to define both *S6* and *S7*) is plotted in Figure 1.

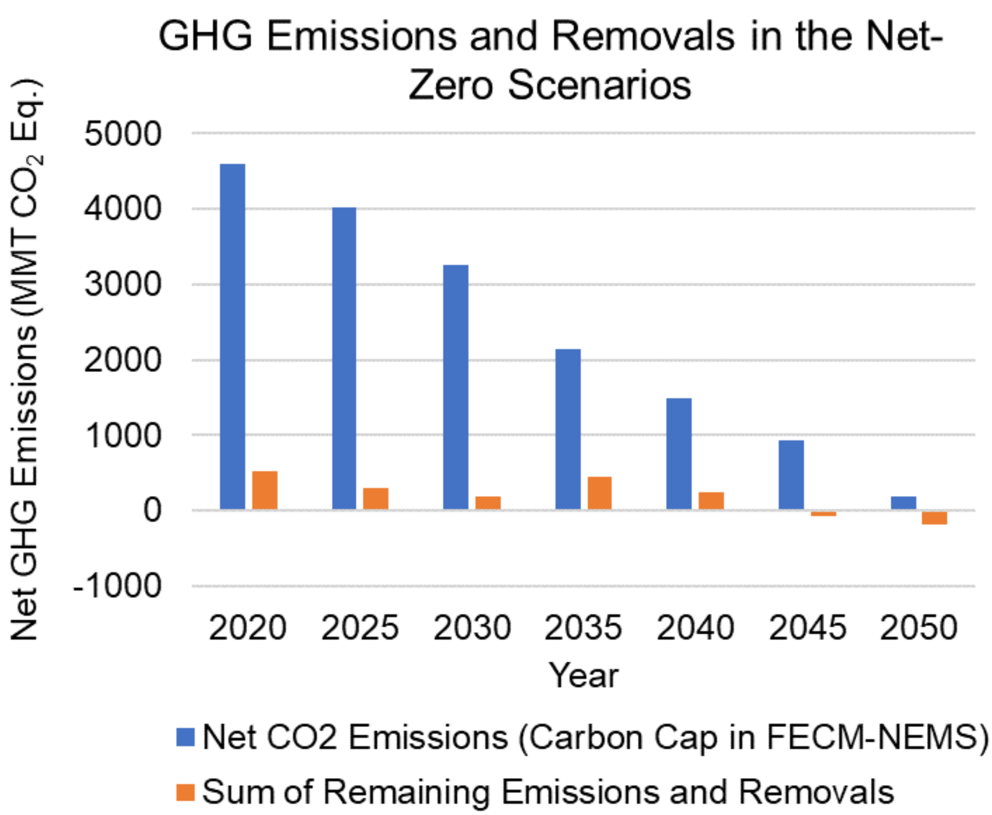

Figure 1. U.S. GHG emissions and removals in the net-zero scenarios

Referring to this carbon cap each model year, FECM-NEMS calculates emissions and removals throughout the model and adjusts a carbon price to equalize them with the carbon cap. With this method, FECM-NEMS ensures that the CO_2 emissions from the energy sector match the corresponding emissions from GCAM. Although FECM-NEMS calculates CH_4 emissions from natural gas systems, they were excluded from the carbon cap in favor of adopting the values calculated by GCAM.

The carbon cap used in FECM-NEMS for both net-zero scenarios ends with 187 MMT CO_2 in 2050. Although this value does not equal zero, it is balanced by the sum of non-energy CO_2, non-CO_2 GHGs, and LULUCF-sector emissions and removals calculated by the GCAM model, which added together total -185 MMT CO_2 equivalent (the total is negative because of large quantities of LULUCF-sector removals). The remaining emissions and removals (non-energy CO_2, non-CO_2 GHGs, and LULUCF) are treated as exogenous to FECM-NEMS and could be added with the endogenous CO_2 emissions to calculate net total GHG emissions (which would equal near-zero in 2050). The sum of non-energy CO_2, non-CO_2 GHGs, and LULUCF-sector emissions and removals is also plotted in Figure 1.

C. Life Cycle Analysis Model and Analysis Methodology [In Progress]

V. Results

A. U.S. LNG exports

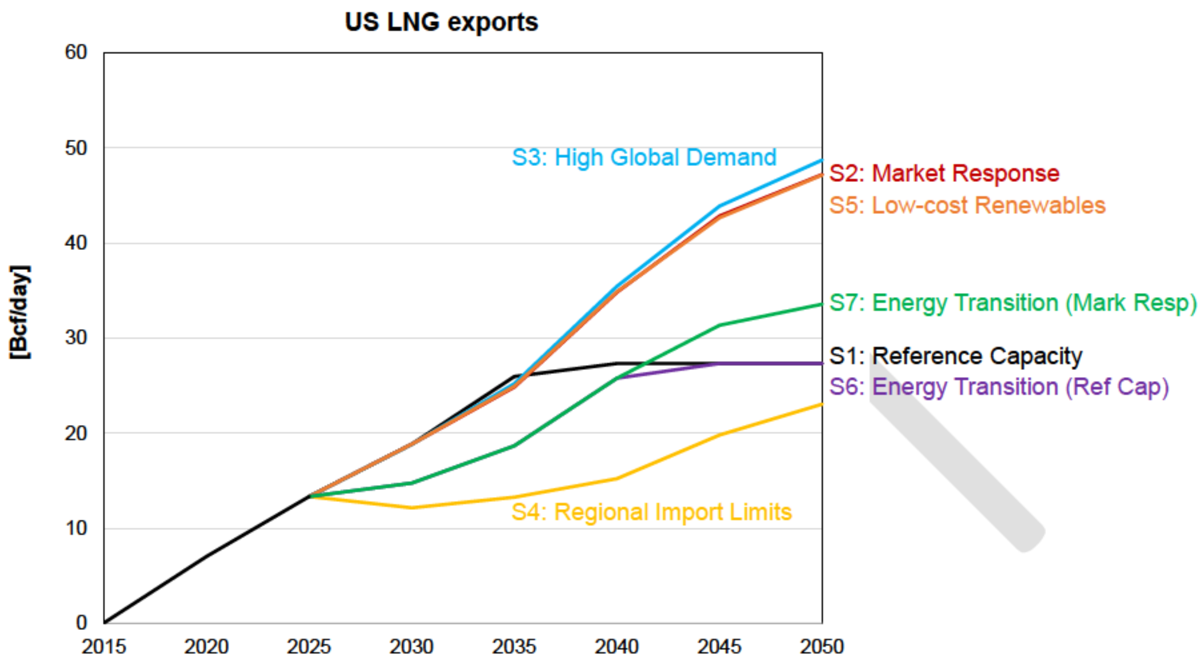

Figure 2. U.S. LNG exports across the scenarios

U.S. LNG exports increase beyond existing and planned capacity in all scenarios by 2050, except *S1* in which U.S. LNG export volumes follow AEO2023 and *S6* in which export volumes are limited to AEO2023 by design. Additionally, in all scenarios, the U.S. is a net exporter of natural gas. Under *S2* in which all outcomes – including U.S. LNG exports – are economically driven and market-based, U.S. LNG exports increase to ~47 Bcf/day in 2050. U.S. LNG exports under *S3* increase to 49 Bcf/day in 2050, emerging as the upper bound. With higher population assumptions in *S3*, total energy demand – and consequently gas demand – outside the U.S. increase compared to *S2*, resulting in an increase in U.S. LNG exports to satisfy the increased international demand. However, the increase is not proportional to the increase in population, because part of the higher demand in *S3* is supplied by an increase in international production. U.S. LNG exports under *S4* increase only to ~23 Bcf/day in 2050, emerging as the lower bound. The lower increase in U.S. LNG exports in *S4* compared to other scenarios is driven by international limits on natural gas imports to maximize the use of domestically produced gas. U.S. LNG exports under *S5* increase to approximately the same level as *S2* in 2050. This is mainly because cheaper solar and wind technologies in this scenario mostly displace fuels other than gas (e.g., biomass). Hence, the demand for gas and consequently, U.S. LNG exports remain materially unaffected compared to *S2*. Under *S7* which assumes a global transition toward 1.5°C, U.S. LNG exports continue to increase, albeit at a lower level than *S2,* to ~34 Bcf/day in 2050. As we discuss subsequently, the lower increase in U.S. LNG exports in this scenario compared to *S2* is driven by the economy-wide transition to low-carbon fuels to meet emission reduction commitments and pledges.

B. Global gas consumption, production, and trade under scenarios *S1* and *S2*

Under scenario *S1*, production, consumption, and trade of gas increase in all regions across the globe (Figure 3) driven by growing demands in the electricity generation, industrial, and buildings sectors (see Figure A-1 in appendix A). Under *S1*, U.S. LNG exports follow the AEO2023 Reference case to grow to 27.34 BCF/day by 2050 (by design). Under *S2: Market Response* – which assumes economically-driven outcomes - U.S. natural gas production and LNG exports increase compared to *S1* to satisfy the growing demands of natural gas globally (Figure 4). Under *S2*, U.S. LNG exports grow to ~47 Bcf/day by 2050. In this scenario, the availability of additional U.S. gas in the global gas market at competitive prices results in a reduction in production and LNG exports from other parts of the world. The increased availability of U.S. LNG in the global market also results in higher LNG imports and reduced pipeline trade outside of the U.S. However, global gas consumption in *S2* increases only by a very small amount (<5% by 2050 globally compared to *S1*). This is mainly because, the availability of additional U.S. LNG in the global market does not materially affect the relative competitiveness of gas compared to other fuels (e.g., coal, oil, renewables, and nuclear) globally. In addition, these scenarios include current emission reduction policies in the U.S. and internationally. Hence, the potential for gas consumption to grow in response to the availability of additional U.S. gas in the global market is limited. Consequently, global primary energy consumption and GHG emissions under *S2* do not change much compared to *S1* (Figure 5).

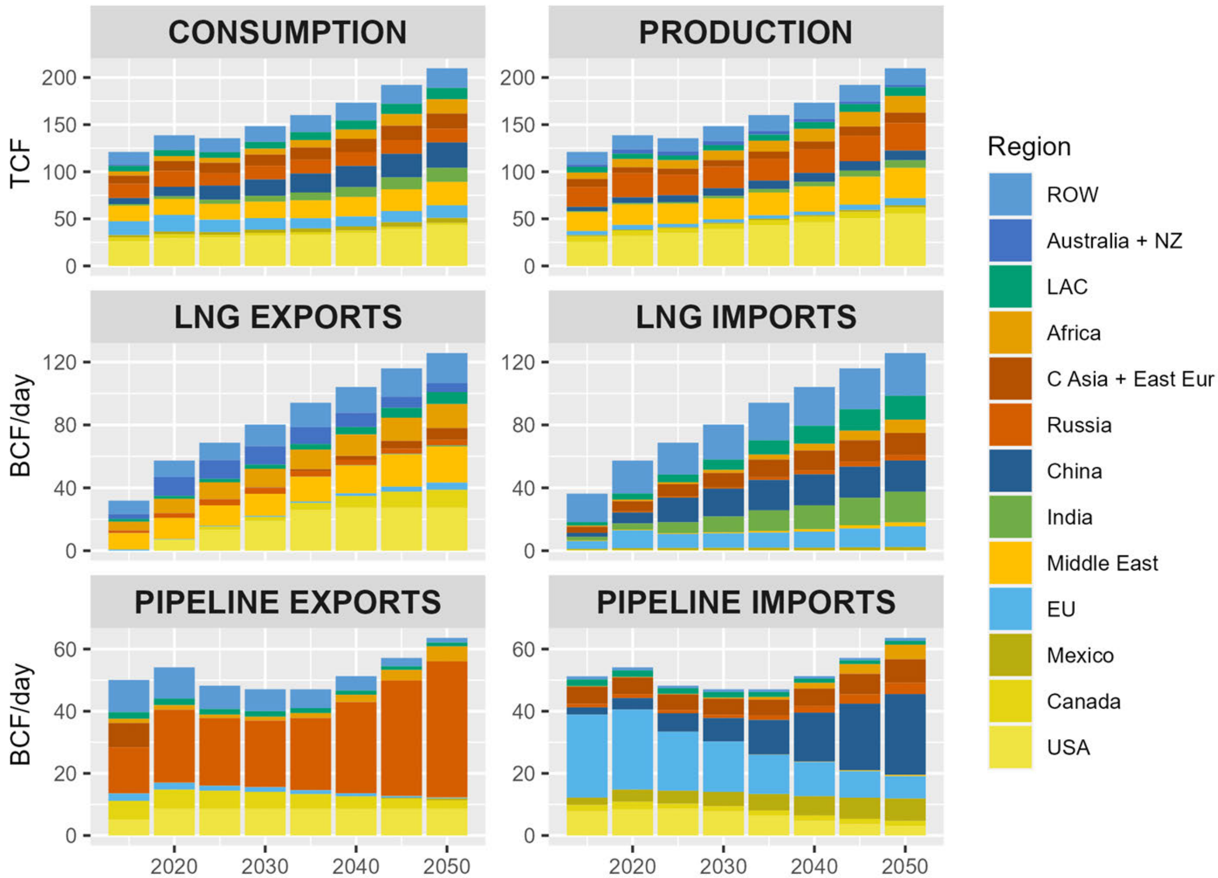

Figure 3. Natural gas consumption, natural gas production, LNG exports , LNG imports, pipeline exports, and pipeline imports by region under S1: Reference Capacity *from 2015 through 2050.*

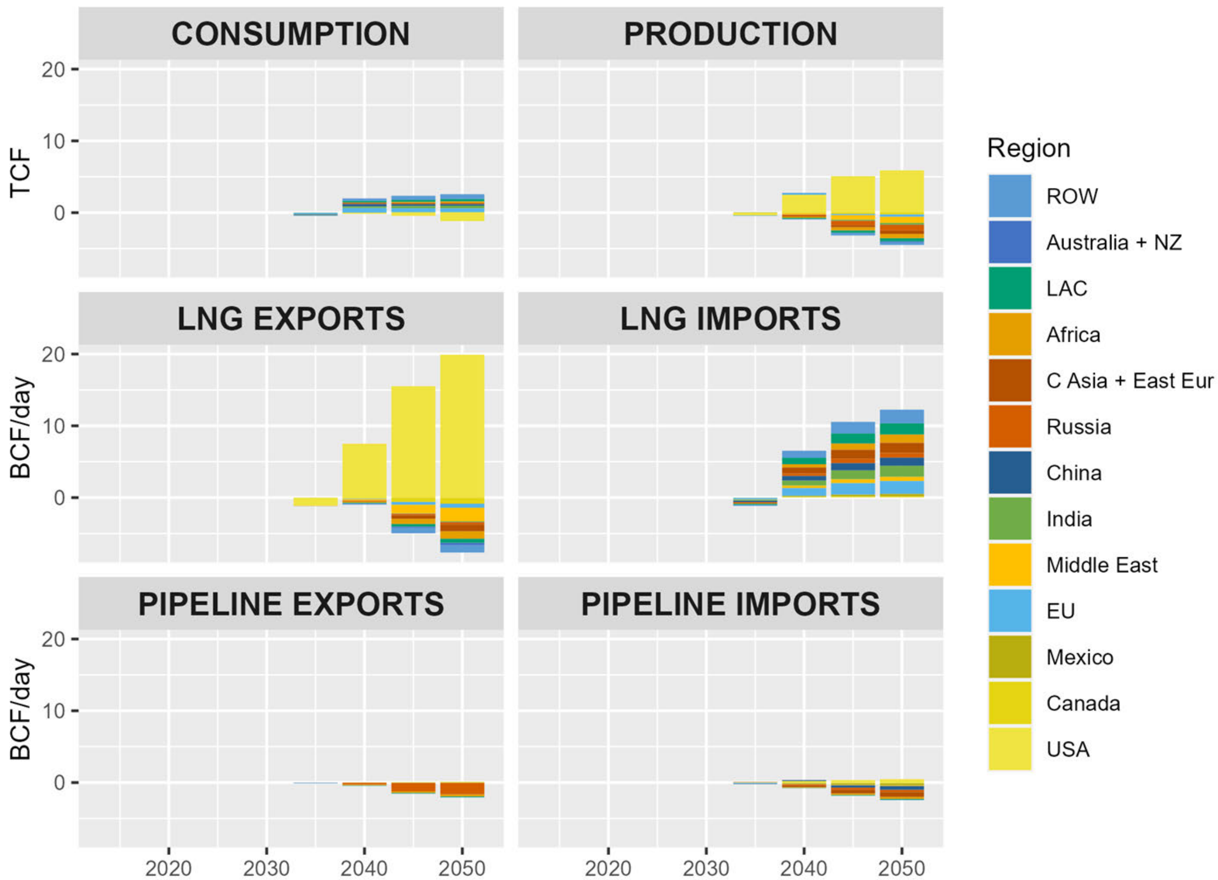

Figure 4. Changes in natural gas consumption, natural gas production, LNG exports, LNG imports, pipeline exports, and pipeline imports by region under S2: Market Response *relative to* S1: Reference Capacity

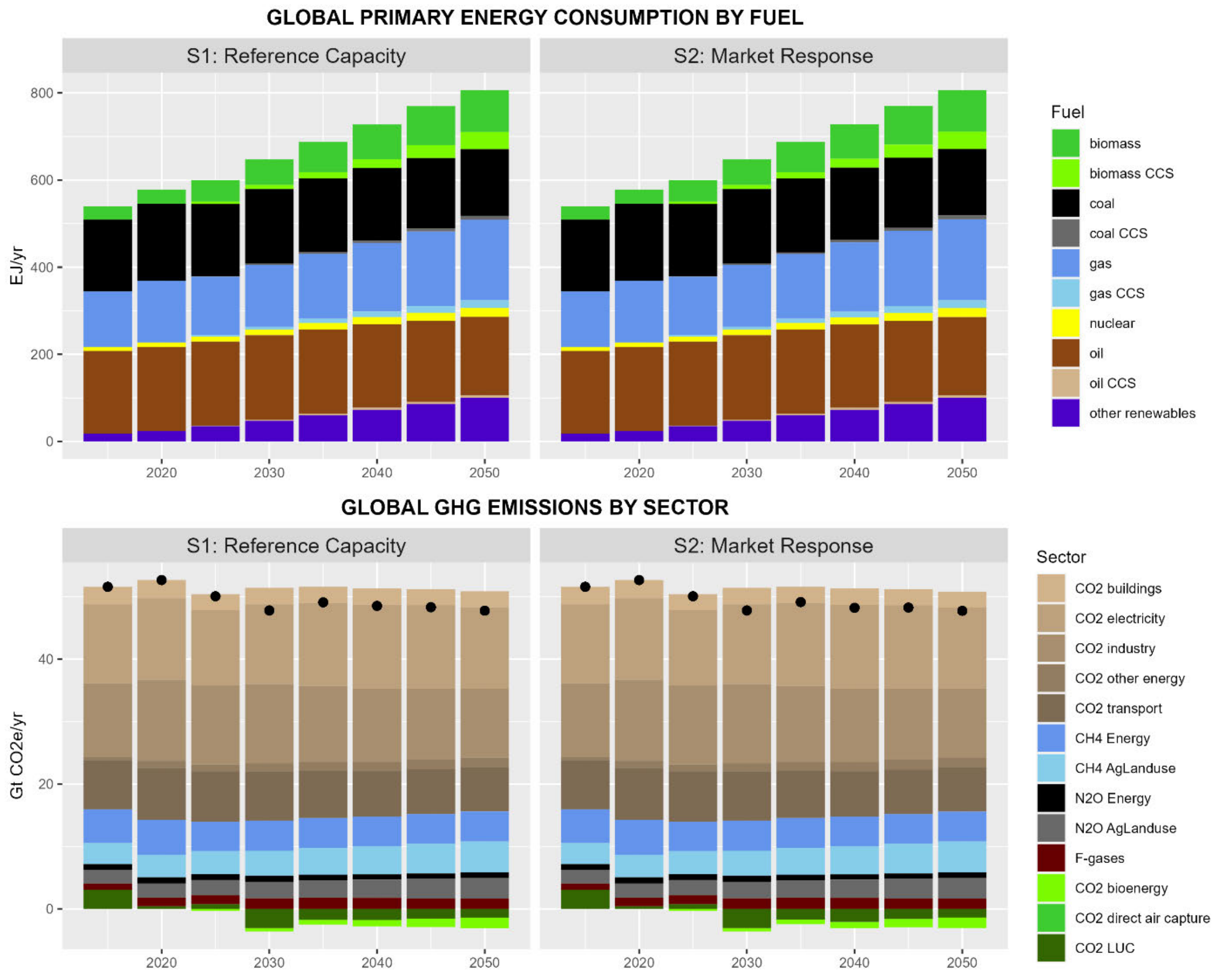

Figure 5. Global primary energy consumption by fuel and greenhouse gas emissions by sector under the S2: Market Response *and the* S1: Reference Capacity *scenarios. Net greenhouse gas emissions are shown as a dot in each bar.*

C. Global primary energy consumption by fuel and GHG emissions by sector under *S6* and *S7*

Under the *S6: Energy Transition (Ref Cap)*, and *S7: Energy Transition (Mark Resp)* scenarios, global GHG emissions from all sectors of the economy reduce significantly compared to *S1* and *S2* (Figures Figure 6, and Figure 7). These scenarios are characterized by a combination of the following decarbonization strategies: i.) a reduction in fossil fuel consumption w/o carbon capture utilization and storage (CCUS), ii.) increased deployment of CCUS with fossil fuels, iii.) increased deployment of renewables, iv.) a net reduction in energy consumption, and v.) increased deployment of carbon dioxide removal (CDR) applications such as bioenergy in combination with CCUS (BECCS), afforestation, and direct air capture (DAC) compared with *S1* and *S2*. Notably, the scale and distribution of CDR deployment varies by type and region. By 2050, about 6.8, 4, and 0.4 GtCO2e respectively of BECCS, afforestation, and DAC are deployed globally in *S6* and *S7* (Figure 8). While BECCS and afforestation are distributed more evenly across regions, most of the DAC is deployed in the U.S. primarily due to the availability of carbon storage. Note that *S6* and *S7* do not assume the availability of any emissions trading or offset mechanisms. Hence, countries with net-zero pledges – such as the U.S. – are assumed to meet those pledges in the stated target years through a combination of the above decarbonization strategies including CDR deployment within their own geographic boundaries. Under these scenarios, although global GHG emissions are net-positive (~20 GtCO2e), global CO_2 emissions are ~0 in 2050. These global emissions outcomes are broadly consistent with 1.5°C scenarios in the literature.

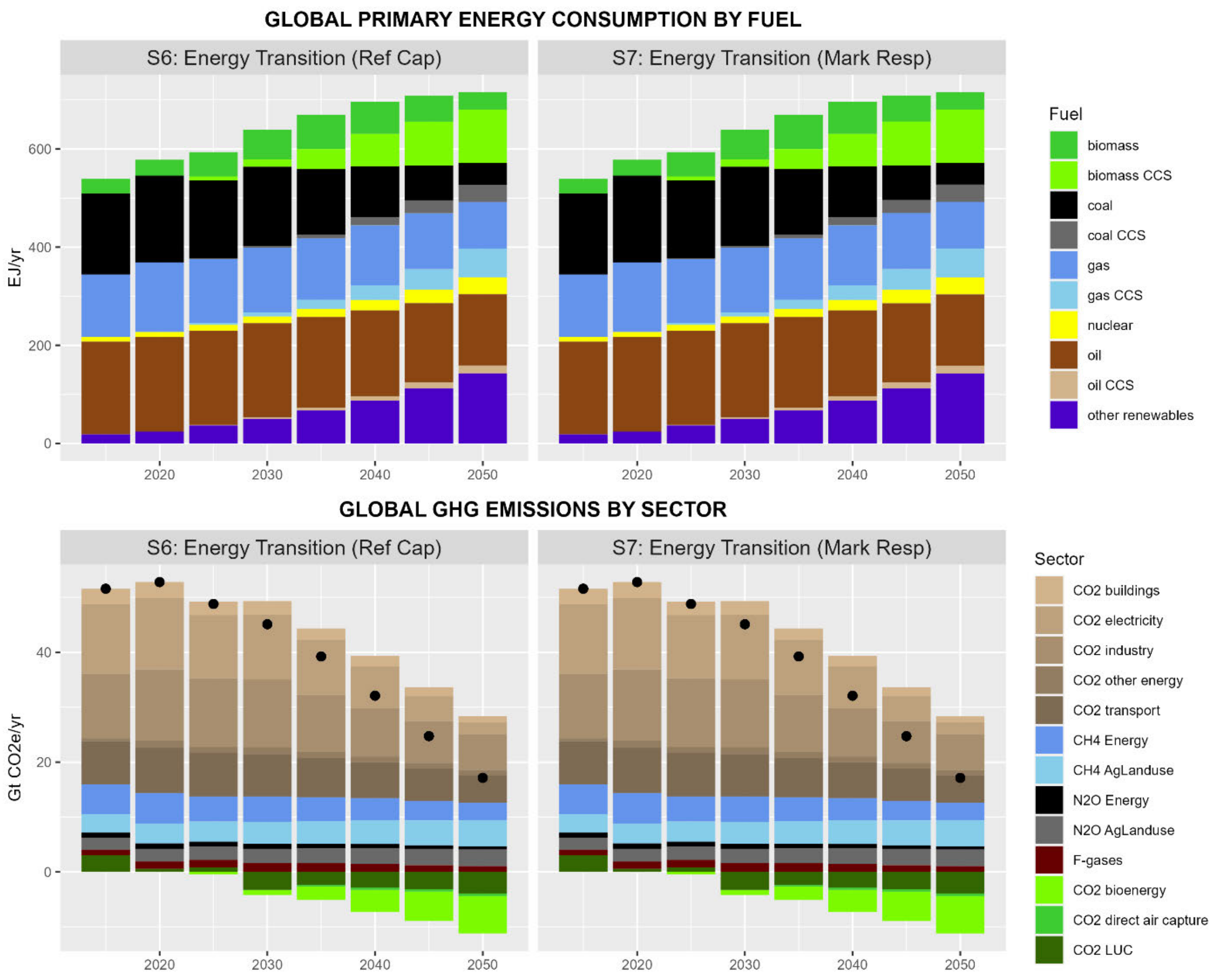

Figure 6. Global primary energy consumption by fuel and GHG emissions by sector under the S6: Energy Transition (Ref Cap) *and* S7: Energy Transition (Mark Resp) *scenarios. Net greenhouse gas emissions are shown as a dot in each bar.*

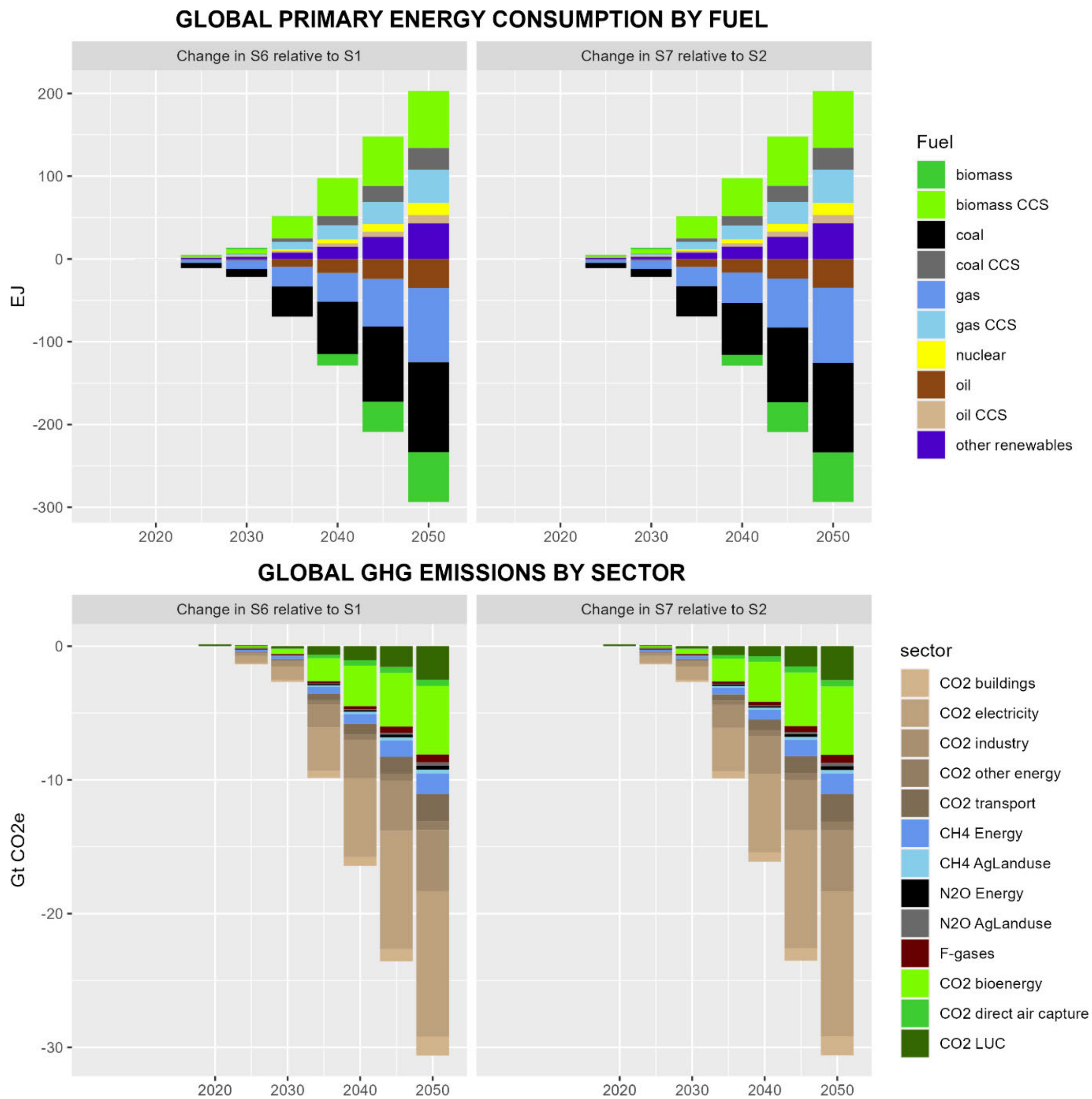

Figure 7. Changes in global primary energy consumption by fuel and GHG emissions by sector under the S6: Energy Transition (Ref Cap) *and* S7: Energy Transition (Mark Resp) *scenarios relative to* S1: Reference Capacity *and* S2: Market Response *scenarios respectively*

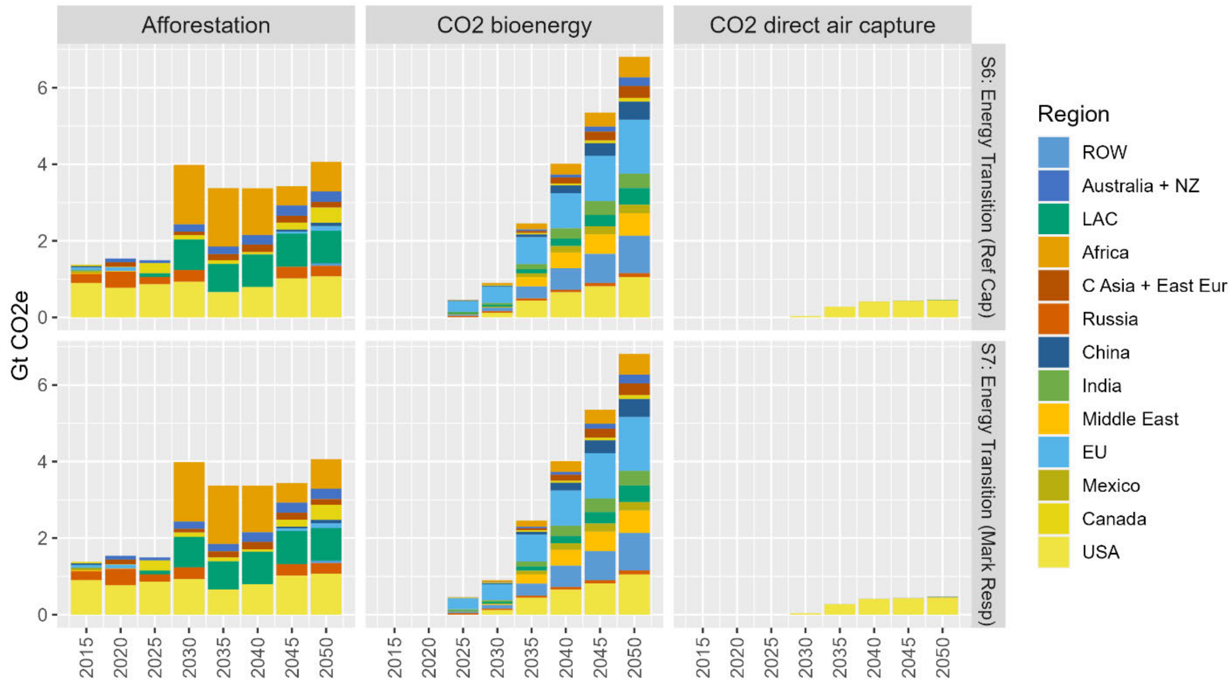

Figure 8. CDR deployment by type and region in **S6** *and* **S7**

D. Global gas consumption, production, and trade under scenarios *S6* and *S7*

Under *S6* and *S7*, gas consumption decreases compared to *S1* and *S2* in most regions largely driven by official net-zero pledges that require complete decarbonization of energy systems by 2050 (Figures Figure 9 and Figure 10). However, in some regions with net-zero pledges that extend beyond 2050 (e.g., India), gas demand continues to grow through 2050 and consumption does not change much compared to *S1* and *S2*. Globally, although gas consumption in *S6* and *S7* is lower compared to *S1* and *S2*, it continues to grow due to the deployment of gas with CCUS in power and industrial sectors, and direct air capture (DAC) applications (Figure A-2). The lower gas consumption in *S6* and *S7* compared to *S1* and *S2* results in lower global production, LNG exports, and LNG imports.

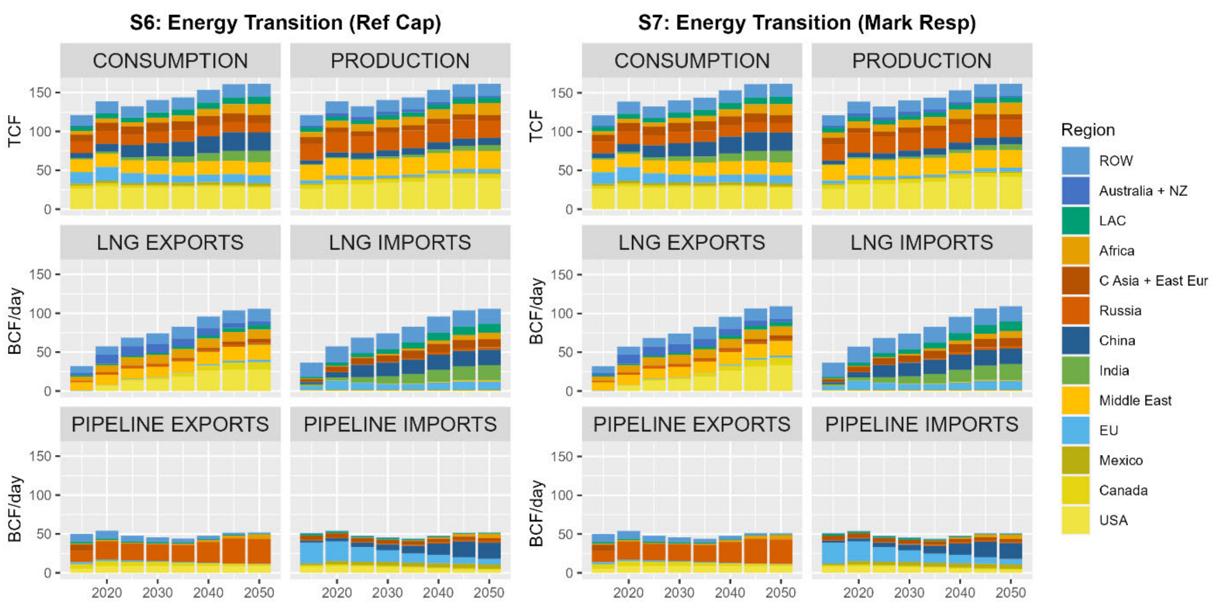

Figure 9. Natural gas markets in S6 and S7.production, natural gas consumption, LNG exports, LNG imports, pipeline exports, and pipeline imports by region under S6: Energy Transition (Ref Cap) *and* S7: Energy Transition (Mark Resp)

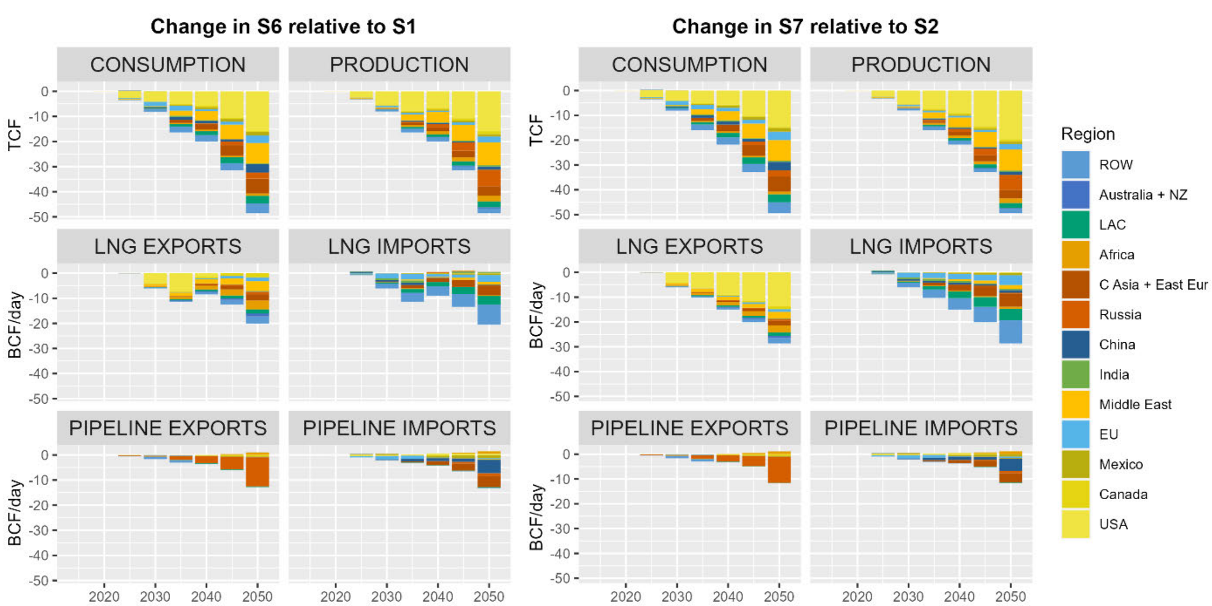

Figure 10. Changes in natural gas markets in S6 vs. S1. *production, natural gas consumption, LNG exports, LNG imports, pipeline exports, and pipeline imports by region under* S6: Energy Transition (Ref Cap) *relative to* S1: Reference Capacity *and* S7: Energy Transition (Mark Resp) *relative to* S2: Market Response.

S6 and *S7* differ in the role of U.S. LNG exports in the global gas market (Figure 11). By 2050, U.S. LNG exports in *S6* are not different from *S1* because this scenario assumes the *S1* values (which are in turn based on AEO2023) as an upper bound. Under *S7* – which assumes economically driven outcomes - U.S. LNG exports continue to grow and increase beyond *S6* – particularly after 2040 – to meet the global demand for gas, a growing share of which is deployed in combination with CCUS in the power and industrial sectors (Figure A-1). Similar to the comparison between *S1* and *S2*, the availability of additional U.S. LNG in *S7* results in a very small increase in gas consumption, reduction in production, reduction in LNG exports, increase in LNG imports, and reduction in pipeline trade in the rest of the world compared to *S6*.

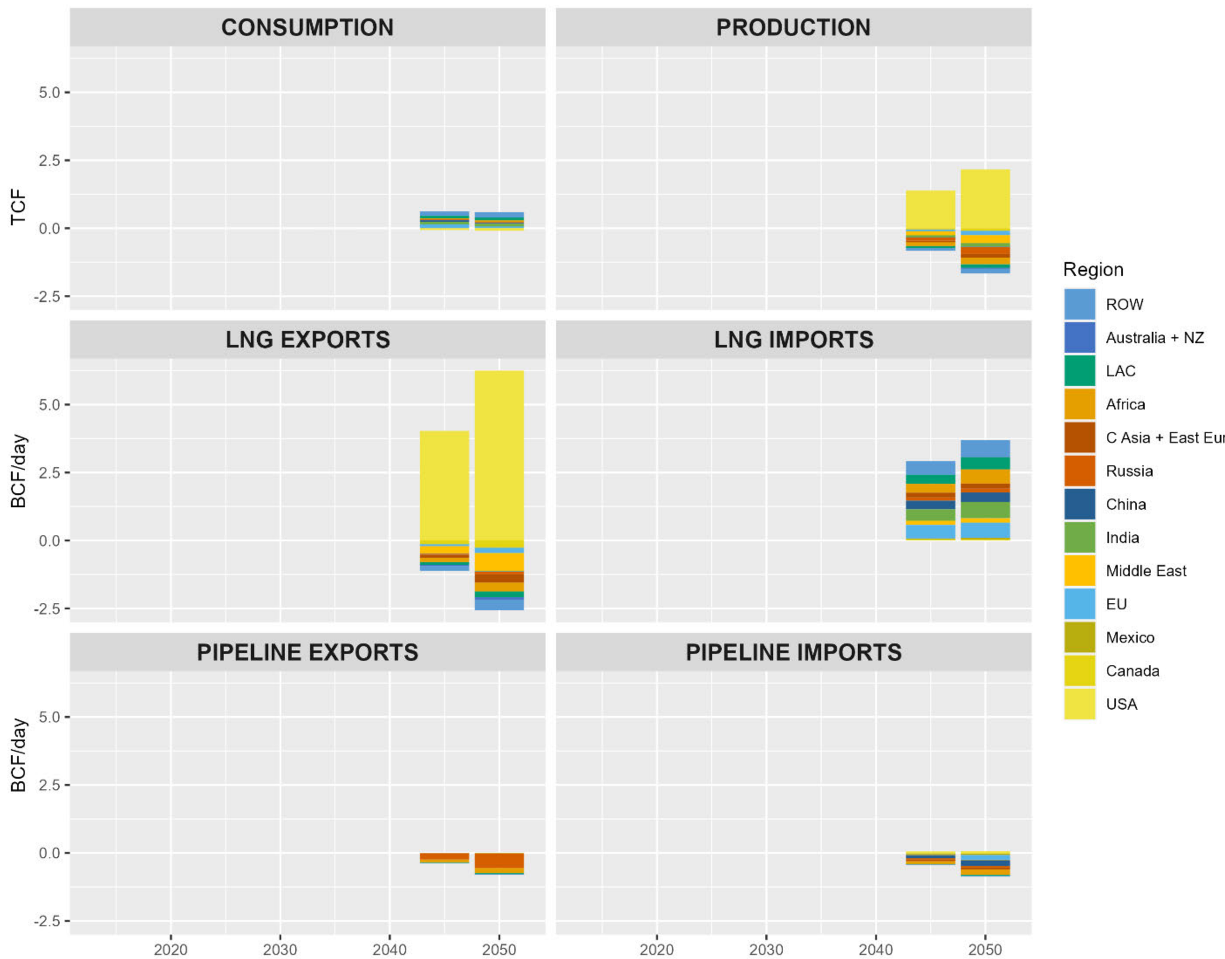

Figure 11. Changes in natural gas markets in S6 vs. S7. *production, natural gas consumption, LNG exports, LNG imports, pipeline exports, and pipeline imports by region under* S7: Energy Transition (Mark Resp) *relative to* S6: Energy Transition (Ref Cap).

E. Global primary energy consumption and greenhouse gas emissions across all scenarios

Overall, the seven scenarios explored in this study result in a range of outcomes for global energy consumption and emissions by 2050 (Figure 12). While total energy consumption and GHG emissions are the highest under the *S3* scenario driven by higher population growth and associated increases in energy demand, the fuel composition and sectoral allocation of GHG emissions are relatively similar across scenarios *S1* through *S5*. In addition, total emissions in 2050 under scenarios *S1* through *S5* are relatively similar to 2015 levels because these scenarios include current policies and measures to reduce emissions.[11,12] However, energy consumption in 2050 is significantly higher compared to 2015 in these scenarios driven by growing population and economic growth. By contrast, total energy and emissions are lowest in scenarios *S6* and *S7* due to the emission pledges. As described earlier, these scenarios are also characterized by significant changes in the fuel composition of global energy consumption and the deployment of carbon dioxide removal technologies.

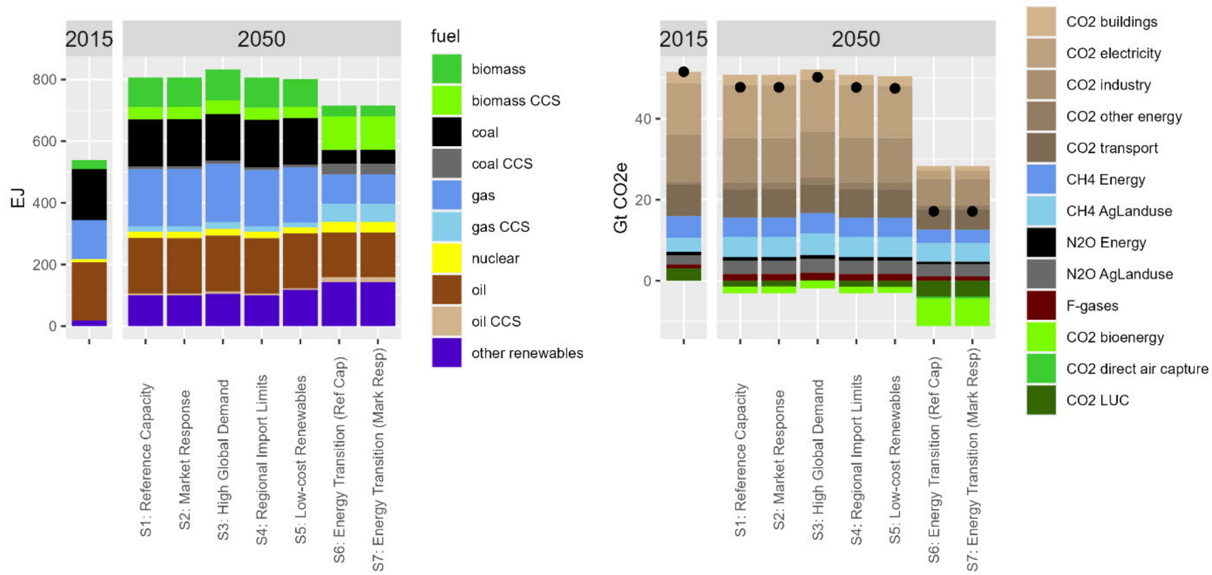

Figure 12. Primary energy consumption by fuel and GHG emissions by sector in 2015 and 2050 under all scenarios. Net greenhouse gas emissions are shown as a dot in each bar.

F. Implications for U.S. Energy Systems

United States LNG exports have steadily increased since 2016 when two liquefaction trains at Sabine Pass, Louisiana went online with a total capacity of 1.2 bcf/day (432 bcf per annum).[13] As of 2022 U.S. LNG exported averaged around 11.2 (Bcf/d) making the U.S. the largest LNG exporter globally. The growth in the U.S. LNG export market is largely attributed to the availability of recoverable resources, particularly tight and shale gas.[14] Technological developments in hydraulic fracturing and horizontal drilling enabled the extraction of natural gas from such unconventional resources. According to the 2023 Annual Energy Outlook published by Energy Information Administration the U.S had about 2,973 Tcf of technically recoverable natural gas resources from both conventional and unconventional resources. Tight and shale gas accounts for approximately two-thirds of the total natural gas resource.

[13] GIIGNL. (2017). The LNG Industry GIIGNL Annual Report. Available at: https://giignl.org/wp-content/uploads/2021/08/giignl_2017_report_2.pdf.
[14] U.S. EIA. (2023). Annual Energy Outlook 2023. Available at: https://www.eia.gov/outlooks/aeo/narrative/index.php

1. Energy Impacts

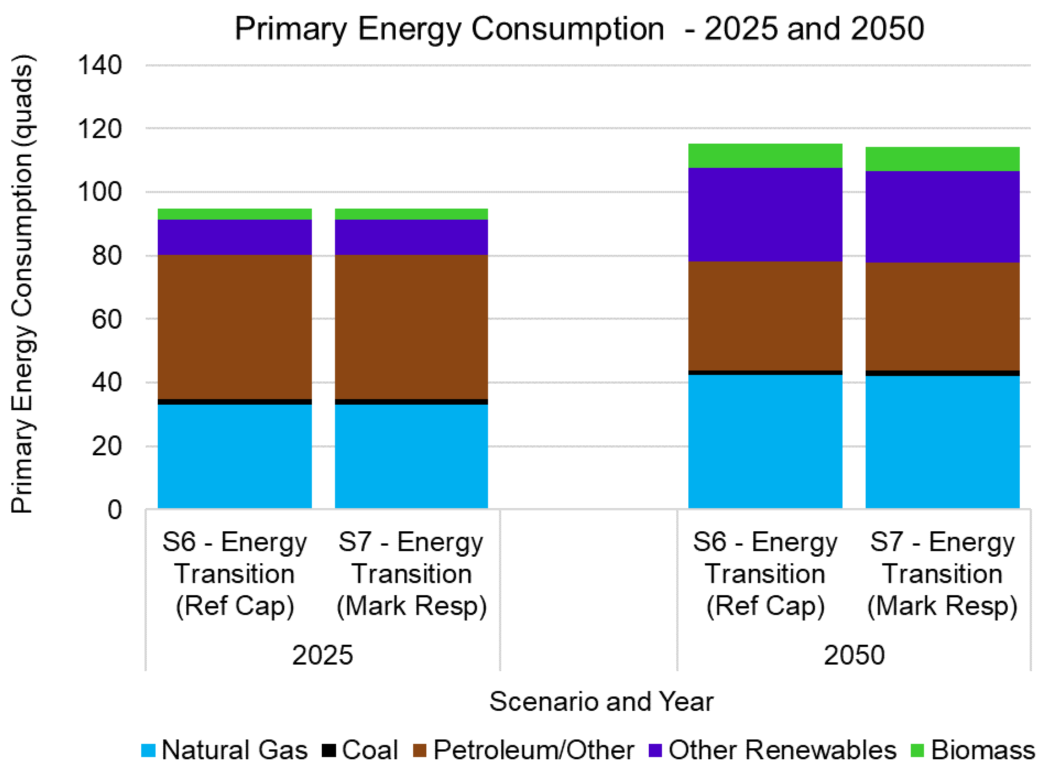

Figure 13. U.S. Primary Energy Consumption S6 and S7.

Figure 13 shows primary energy consumption across the Net-Zero scenarios in 2025 and 2050. In 2025, U.S. primary energy consumption is predominantly driven by fossil fuels, which account for 85% of the total energy use. By 2050, energy consumption rises across both scenarios relative to 2025, distinguished by a notable increase in biomass and other renewables. Relative to *S6*, increased LNG exports in *S7* put pressure on the natural gas market, leading to slightly higher end-use prices, more expensive mitigation strategies and an implied carbon tax. Biomass and other renewable sources grow by 22.3 and 22.1 quadrillion BTUs from 2025 in the *S6* and *S7* cases respectively, thereby contributing 32.1% of the total energy consumption in both cases. Natural gas consumption increases from 33 quadrillion BTUs in 2025 to 42.5 and 42.1 quadrillion BTUs in the energy transition scenarios *S6* and *S7* respectively. Remaining primary energy, primarily petroleum, decreases across both cases from 45.2 quadrillion BTUs in 2025 to 34.4 quadrillion BTUs in *S6* and 34.0 quadrillion BTUs in *S7* by 2050.

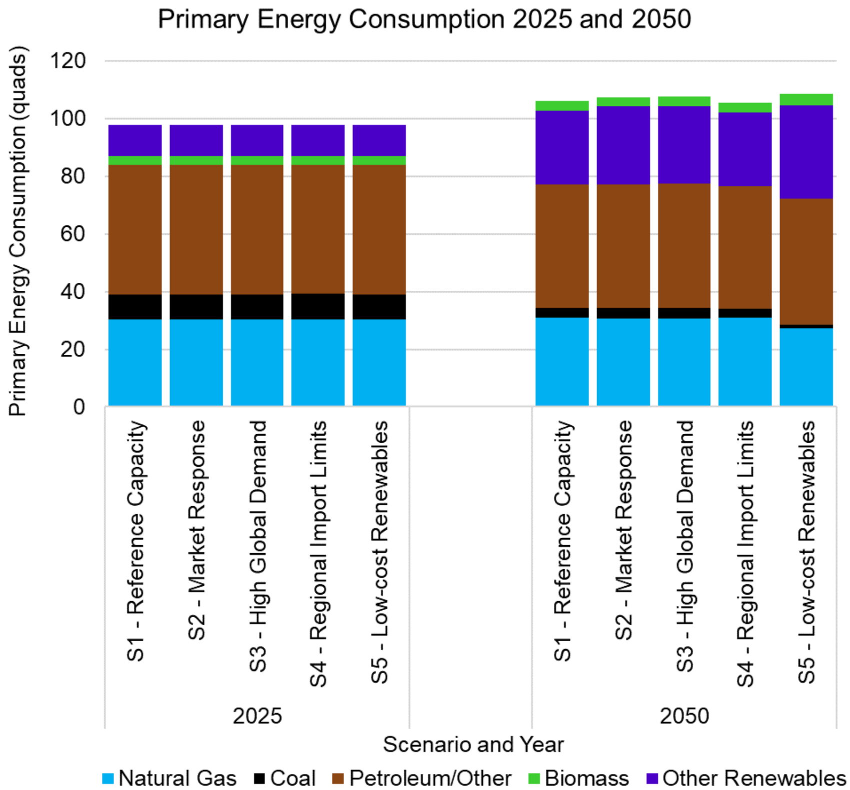

Figure 14. U.S. Primary Energy Consumption S1 – S5.

In 2025, the primary energy consumption at approximately 98 quadrillion BTUs in scenarios *S1* through *S5*. By 2050, all scenarios see an increase in total energy consumption, exceeding 105 quadrillion BTUs. The highest energy consumption is recorded in scenario *S5* at 109 quadrillion BTUs, and the lowest consumption is in scenario *S4* at 105 quadrillion BTUs.

The availability of low-cost renewables in scenario *S5* fosters the deployment of biomass and other renewable energy sources. A substantial decrease is noted in coal usage, with the most significant reduction occurring in scenario *S5*. Natural gas consumption remains steady across scenarios *S1* through *S4*, hovering around 31 quadrillion BTUs, but experiences a decline to 27 quadrillion BTUs in scenario *S5*.

2. Natural Gas Market Results

a) Natural gas production and consumption, S1 through S5

U.S. natural gas production increases across most cases to maintain the elevated export volumes. U.S. natural gas consumption, on the other hand, is relatively unchanged across the first four scenarios. Figure 15 plots total U.S. natural gas production and consumption values over time.

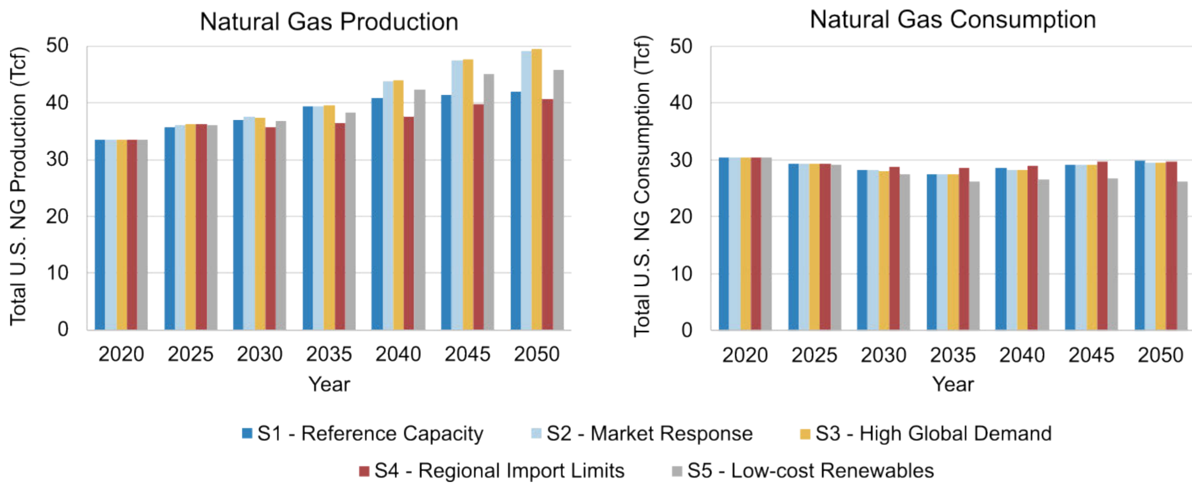

Figure 15. Total U.S. natural gas production and consumption volumes over time, by scenario

From a starting point of 33.5 Tcf of natural gas production in 2020 (equal to 91.5 Bcf/d), production in each scenario increases following a path that correlates with their LNG export curve. Natural gas production in *S1*, *S2*, and *S3* follows a similar trajectory by 2035, reaching 39.4-39.5 Tcf. *S1* production then slows through 2040 and reaches a peak of 42.0 Tcf by 2050. *S2* and *S3* production values accelerate through 2050, reaching 49.0 Tcf and 49.5 Tcf, respectively. Similar to the trends in LNG exports, *S4* production exhibits the lowest values for most of the model time, ending slightly below *S1* at 40.7 Tcf in 2050. *S5* production exhibits the same general path as *S2* and *S3*, but grows more slowly, reaching 38.2 Tcf and 45.7 Tcf in 2035 and 2050, respectively.

The natural gas consumption volumes from *S1-S3* follow similar paths, dipping from 30.5 Tcf in 2020 to 27.4-27.6 Tcf in 2035 before ramping up to 29.6-29.8 Tcf in 2050. Although *S4* had exhibited lower LNG export and natural gas production quantities, the consumption volumes in *S4* remain slightly higher than the volumes in *S1-S3* through most of model years, equalizing with *S1-S3* in the final timestep. *S4* reports 28.5 Tcf of natural gas consumption in 2035 and 29.8 Tcf in 2050. *S5* is the largest outlier with the lowest consumption of 26.2 Tcf in 2035 and almost no change in consumption values between 2035 and 2050.

The reduced natural gas production and consumption volumes from *S5* (when compared to *S2* and *S3*) are explained by the effect of low renewables costs on the energy system. Because *S5* adopts many of the same inputs as EIA's AEO23-NEMS low zero-carbon technology cost case, it exhibits the same behavior of switching from natural gas to cheaper renewable energy sources, affecting both production and consumption. The remaining scenarios show similar levels of natural gas consumption, but different levels of natural gas production, suggesting that most increases in natural gas production are passing directly to LNG exports.

b) Natural gas production and consumption, net-zero scenarios

Figure 16 plots the natural gas production and consumption for the two net-zero scenarios.

S6 and *S7* production are 37.6 Tcf and 37.1 Tcf in 2035, respectively, but quickly rise to 54.7 Tcf and 56.5 Tcf by 2050. *S6* and *S7* exhibit a flatter trend in total consumption through 2040, but reach 41.9 Tcf and 41.5 Tcf, respectively, by 2050. The differences between the two net-zero scenarios are similar to differences observed between *S1* through *S5*: changes in production are correlated with changes in LNG exports, but differences in consumption between scenarios are minimal.

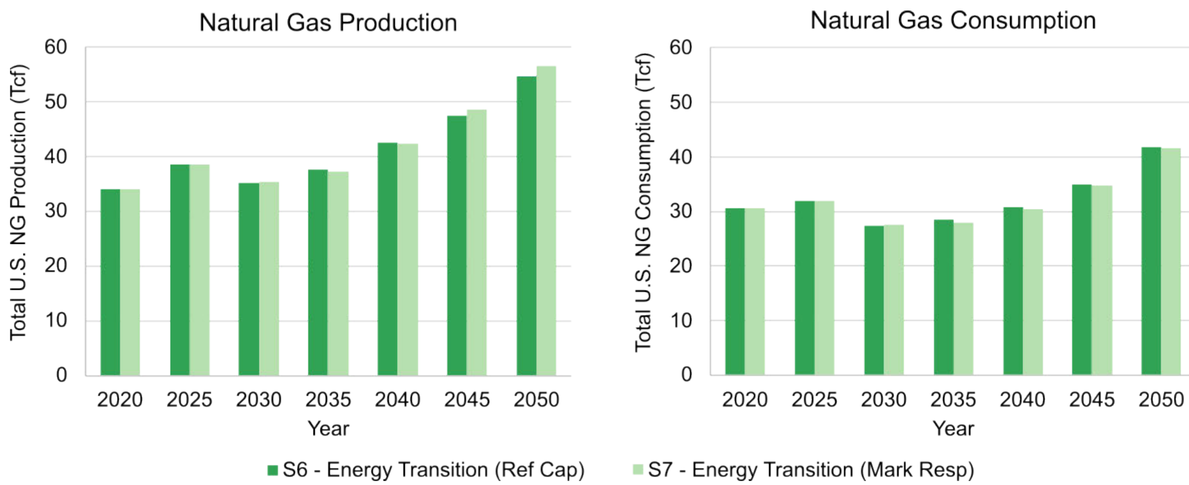

Figure 16 Total U.S. natural gas production and consumption volumes net-zero scenarios

The rapid increase in natural gas production and consumption for the net-zero scenarios after 2040 comes from a substantial increase in natural gas to power direct air capture (DAC) facilities, plotted in Figure B-5**Error! Reference source not found.** of the appendices. Natural gas consumption accounts for 16.8 Tcf and 16.2 Tcf in 2050 for *S6* and *S7*, respectively. More detail on CO_2 emissions and removals is given later in I.F.4**Error! Reference source not found.** "U.S. Greenhouse Gas Results".

c) Natural Gas Henry Hub Prices and Impact on Consumption

Although total U.S. natural gas consumption volumes are similar across the first five scenarios, the increased LNG exports have a moderate effect on natural gas prices. The natural gas price of the net-zero scenarios rises above the prices from *S1* through *S5*, driven mostly by demand for natural gas to power DAC facilities. Figure 17 plots the natural gas price at the Henry Hub in $2022/Mcf over time for all scenarios.

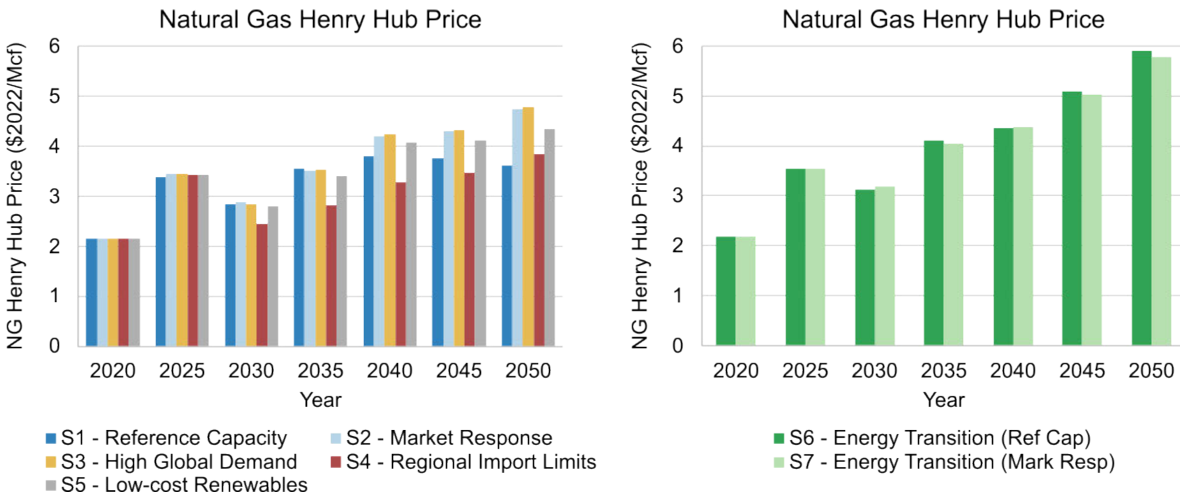

Figure 17. Total U.S. natural gas Henry Hub price by scenario

The natural gas price in *S1* shows some early fluctuations associated with short-term effects from historical data before increasing to a maximum of $3.80/Mcf in 2040 and easing to $3.61/Mcf in 2050. The natural gas prices in *S2*, *S3*, and *S5* are mostly consistent with the reference case up through 2035 but ultimately rise to levels of $4.74/Mcf, $4.79/Mcf, and $4.35/Mcf, respectively, by 2050. The difference in prices correlate with the differences in their LNG export curves, while LNG exports in *S1* plateau after 2035 and see a drop in natural gas prices. Scenarios *S2*, *S3*, and *S5* all exhibit both increasing exports and prices. *S4* has lower natural gas prices over most of the modeling period, but ultimately exceeds *S1* in 2050 with a price of $3.84/Mcf; the persistent increase in *S4* prices after 2030 is consistent with increases in LNG exports throughout the same time period.

The influence of LNG exports on natural gas prices shown in Figure 17 is similar to the effect reported by EIA in their May 2023 "Issues in Focus" report on LNG.[15] The EIA's "Fast Builds Plus High LNG Price" case, which modeled the effect on U.S. energy markets of accelerated construction of LNG infrastructure in an environment with elevated international demand for LNG, reported a 2050 natural gas price of $4.81/MMBtu (equal to $4.64/Mcf) at 48.2 Bcf/d of exports. These values are close to the results from *S2* of $4.74/Mcf) at 47.2 Bcf/d of exports and demonstrate good agreement between the two studies on the relationship between LNG exports and natural gas prices.

Overall U.S. natural gas consumption does not change appreciably in response to higher prices, but there are some shifts in consumption behavior on a sector-by-sector basis. These sector-specific differences are presented in greater detail in Figure B-3.

The natural gas price of the net-zero scenarios rises above the prices from *S1* through *S5*, driven mostly by demand for natural gas to power DAC facilities. Natural gas prices for the net-zero scenarios are similar to prices in *S1* through 2030, but afterwards rapidly increase on a trajectory consistent with the growth of DAC. *S6* and *S7* reach prices of $5.90/Mcf and $5.77/Mcf, respectively, by 2050. The difference in price between *S6* and *S7* is within the tolerance of the model.

[15] U.S. EIA (2023). AEO2023 Issues in Focus: Effects of Liquefied Natural Gas Exports on the U.S. Natural Gas Market. Available at: https://www.eia.gov/outlooks/aeo/IIF_LNG/pdf/LNG_Issue_in_Focus.pdf.

3. U.S. Macroeconomic Outcomes

While NEMS has rich detail about the energy system, a separate macroeconomic activity module (MAM) provides projections of economic drivers underpinning NEMS' energy supply, demand, and conversion modules. The MAM incorporates IHS Markit's (now S&P Global) model of the U.S. economy, along with EIA's extensions of industrial output, employment, and models of regional economies. The IHS Markit module is modified to include EIA's assumptions on key assumptions, such as world oil price, yielding a baseline trajectory of the economy. Within a NEMS scenario, feedback from the other NEMS modules includes:

- Production of energy, including coal, natural gas, petroleum, biomass, and other fuels,
- Trade in energy, including net exports coal, petroleum, natural gas, and biofuels
- Total and end-use demand for energy, including sales of electricity
- Consumer spending on energy, disaggregated to fuel oil motor fuels, electricity, natural gas, and highway consumption of gasoline
- Energy prices, including a price index for consumer prices and wholesale price
- Industrial production indices for oil and gas extraction and coal mining.

Since the MAM does not track individual projects, GDP estimates do not include economic activity associated with specific export facilities and thus the impacts are approximate.

a) Macroeconomic Effects – Total Economic Activity (GDP)

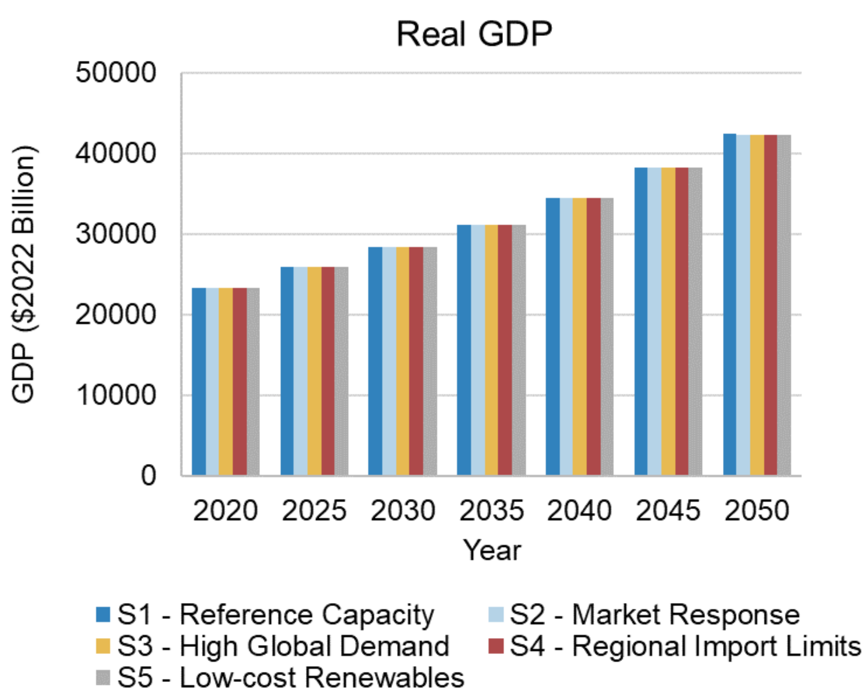

Figure 18. U.S. Real GDP changes

As shown in U.S. GDP growth rate remains essentially constant across all five scenarios, increasing at 1.9% annually. Higher natural gas exports result in higher prices, reducing economic activity in some sectors but increasing in others. The impact of increased exports is positive through 2045. Accelerating prices in the last five years of the projection period tend to slightly reduce overall economic growth. Overall, GDP changes in 2050 are relative to 2020 are within .3% across all five scenarios.

b) Consumer Effects

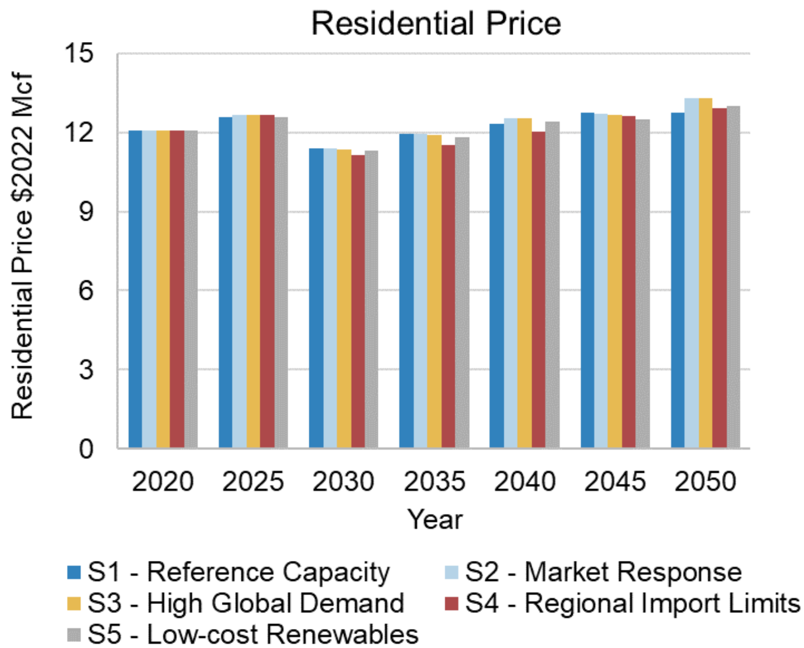

Figure 19. U.S. Residential Gas Prices

Figure 19 shows the residential natural gas price in each of the five key scenarios. Natural gas prices are highest when exports are highest, in the *S3*, Higher Global demand. Overall, natural gas price increases only exceed 4 percent over the *S1* scenario in the final years of the *S3* scenario, otherwise prices are essentially unchanged across the scenarios.

c) Aggregate Consumption and Investment Effects

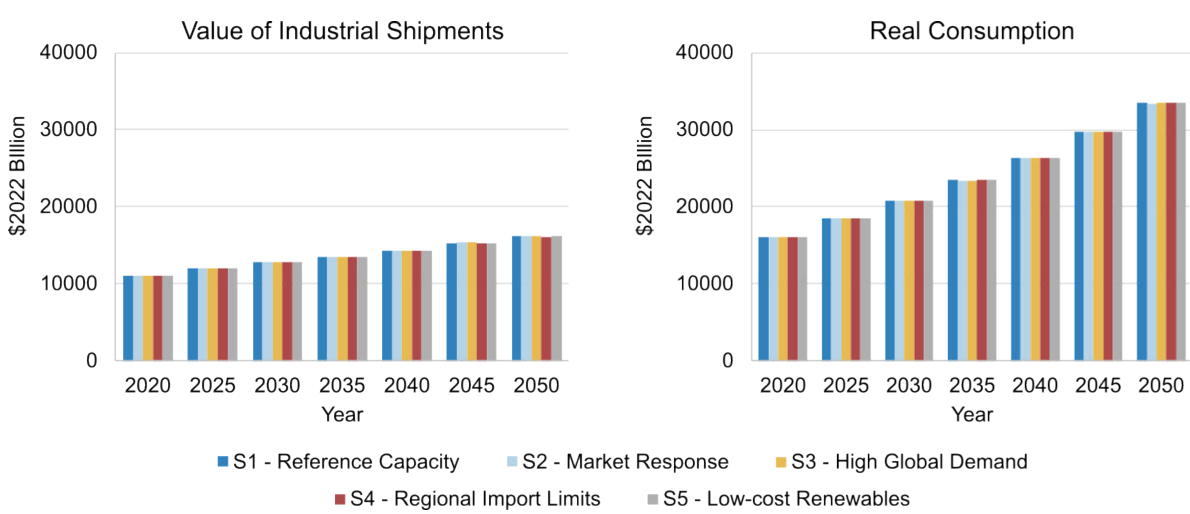

Figure 20. U.S. Value of Industrial Shipments and Real Consumption

One component of GDP tracked by NEMS is the value of industrial shipments, shown in Figure 20. Industrial processes are sensitive to natural gas prices, which generally rise relative to *S1*. However, the increased production, processing and transportation of natural gas also requires additional equipment. Overall, NEMS shows a slight increase in the value of industrial shipments across the scenarios. The largest increase relative to *S1* is approximately 0.2% in 2050.

LNG exports can benefit consumers through increased labor income and the return on capital expended on facilities to produce and export the commodity. Exports increase the value of the dollar, decreasing the cost of some imports. However, increased demand for natural gas, including exports, raises its price and products and of products that require natural gas. This can be observed in the change in aggregate consumption is another component of GDP. When energy prices rise, consumers must pay more for natural gas, but purchases of other goods decrease. Across all the scenarios, this effect is small. While wealth transfers may occur between consumers, as some groups benefit more than others through increased production, this is not reflected in the aggregate output of the model. In 2045, real consumption in Scenarios *2-5* is above that of Scenario 1, while steeper increases in natural gas prices for *S2*-*S5* at the end of the forecast reduce consumption by less than 0.2%.

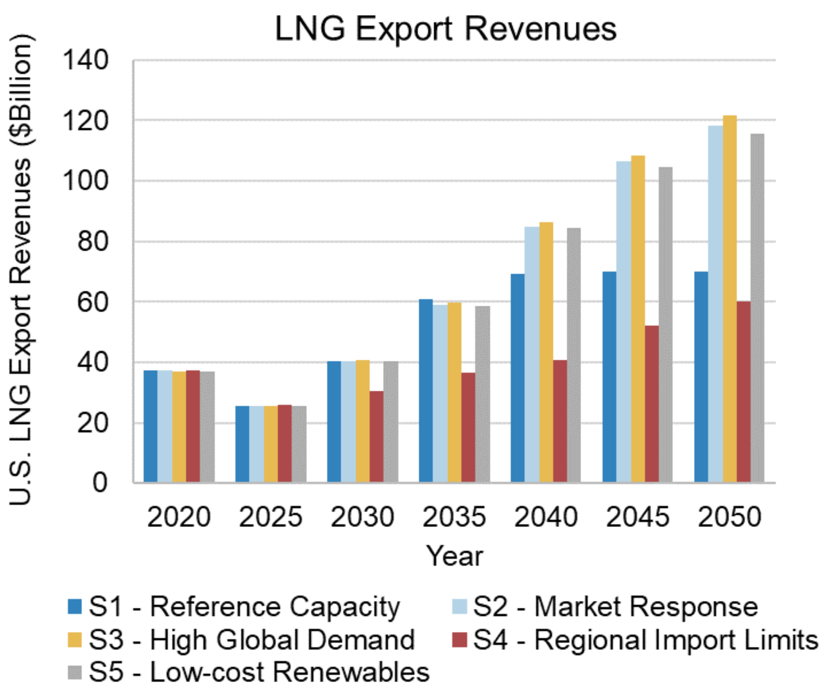

Figure 21. U.S. LNG Export Revenues

Plotted in Figure 21, export revenues are the product of the LNG export volumes and the EU LNG price. In a fully competitive market this price should be sufficient to fully accommodate the production, liquefaction, and transportation of natural gas. Since much of this activity occurs domestically, it is a rough proxy for economic activity engendered by increasing LNG exports.

4. U.S. Greenhouse Gas Results

a) Scenarios 1 through 5

AEO23-NEMS tracks CO_2 emissions from the combustion and use of fossil fuels. These CO_2 emissions do not change significantly between scenarios in response to varying LNG export levels. Figure 22 plots CO_2 emissions from fossil fuels for *S1* through *S5*.

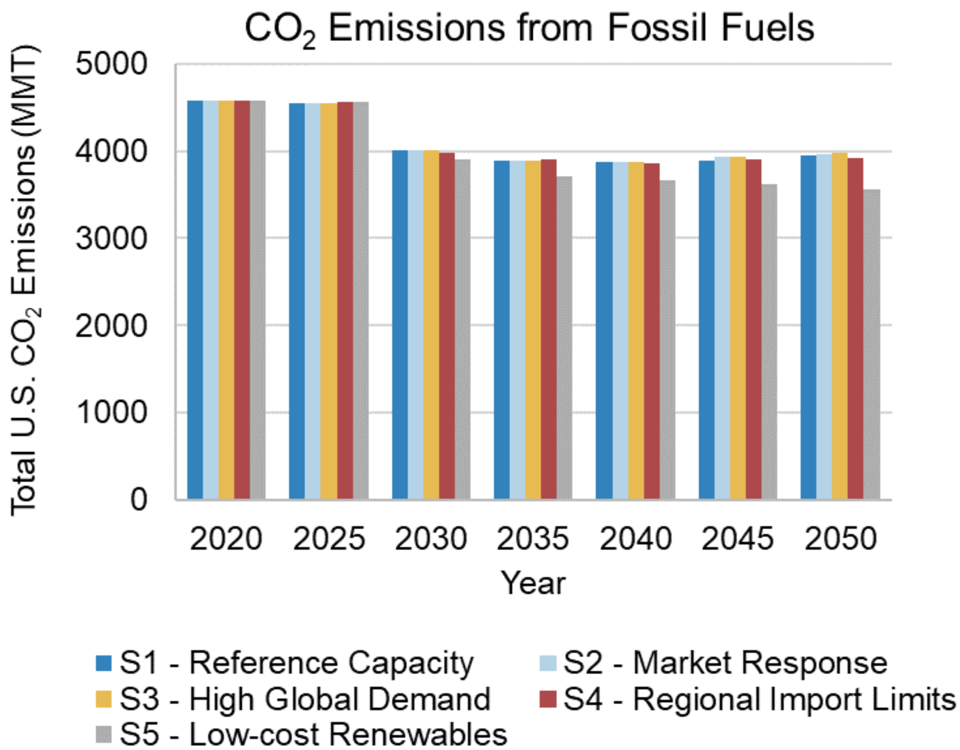

Figure 22. Total U.S. CO_2 emissions from fossil fuel combustion

From a starting point of 4580 MMT CO_2 emissions in 2020, the first four scenarios decline to between 3990 and 4020 MMT CO_2 in 2030 and follow a flatter trajectory to 3930-3980 MMT CO_2 in 2050. There is a weak connection between LNG exports and CO_2 emissions: cases with the highest exports (*S2* and *S3*) have slightly higher CO_2 emissions levels in 2050 of 3970 and 3980 MMT, respectively, whereas cases with lower exports (*S1* and *S4*) report respective CO_2 emissions of 3040 and 3030 MMT. The relationship is small, however, and accounts for only a 1% difference in emissions. The small differences between the first four scenarios are consistent with the relatively unchanged natural gas consumption volumes observed in Figure 15. *S5* is again an outlier, continuing to decrease through 2030 (3910 MMT CO_2) and reaching 3570 MMT CO_2 emissions by 2050. The lower emissions from *S5* are explained by the assumptions used for low renewable costs, rather than by changes in LNG exports.

b) Net-zero scenarios

The net-zero scenarios were modeled in FECM-NEMS, which endogenously calculates some additional emissions that AEO23-NEMS is missing (most relevant being CH_4 leakage from natural gas production and processing infrastructure). To retain consistency between the two models, only the CO_2 emissions reported by FECM-NEMS were included in the analysis and used to define the net-zero GHG scenarios.

The remaining non-CO_2 emissions (which still contribute to the overall net-zero GHG cap) were calculated endogenously within GCAM and used in FECM-NEMS as an exogenous input. More detail on how the net-zero scenarios were designed is available in the section I.B "NEMS Models and Analysis Methodology."

Figure 23 plots the CO_2 emissions and removals for the net-zero scenarios. Both net-zero scenarios exhibit both lower emissions than *S1* and significant amounts of CO_2 removals, reaching net-zero by 2050.

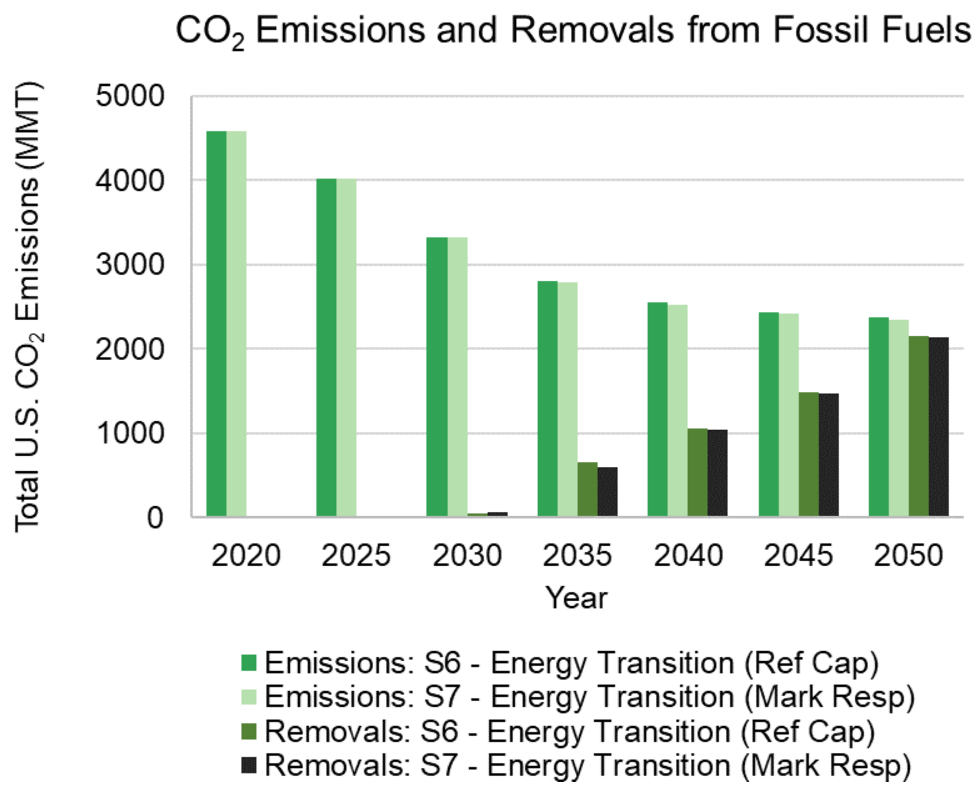

Figure 23. Total U.S. CO_2 emissions and removals, S6 *and* S7

CO_2 emissions from *S6* and *S7* begin at 4580 MMT and decline continuously through 2050, ending at 2370 and 2350 MMT CO_2, respectively. These declines are primarily driven by electrification of broad sections of the economy with a combination of renewables and CO_2 capture and storage. The decline in emissions is accompanied by an increase in removals, which starts growing rapidly in 2030 and eventually reaches 2160 MMT CO_2 for *S6* and 2130 MMT CO_2 for *S7* in 2050. The majority of removals (87-89% by 2050) come from DAC, with the remainder coming from H_2 production with biomass and BECCS. The specific breakdown of removal technologies is explored in Section D of Appendix B. While the removals do not completely cancel out the 2350-2370 MMT of CO_2 emissions, the difference is balanced out by the non-CO_2 emissions calculated within GCAM and used as exogenous inputs, which are net negative.

G. LCA Results [In Progress]

1. Adjusted Global CO2 for Each Scenario

2. Consequential Results of U.S. LNG Production

3. Study Limitations

H. Comparison with Previous Studies

Previous studies have focused on the economic impacts of increased U.S. LNG exports, both domestically and globally. For instance, the 2018 NERA study focused on the domestic economic impact of increased U.S. LNG exports. Since the NERA study of 2018, there have been significant changes in the LNG export market and a renewed emphasis on evaluating the impact of LNG exports on greenhouse gas emissions. Relative to the market, changes include passage of the Bipartisan Infrastructure Law and the Inflation Reduction Act, along with major geopolitical changes due to the war in Ukraine and resulting economic responses. Thus, an updated study is warranted.

Another important goal of this study is to allow the integration of market impacts within the LCA analysis across a wide range of potential scenarios. By introducing an integrated energy-GHG model such as GCAM, the equilibrium level of U.S. exports could be determined along with changes in global greenhouse gas emissions. Similarly, the NEMS model can show domestic changes in energy-related GHG emissions at different export levels. Furthermore, including NEMS and GCAM broadens the range of scenarios to include those with net-zero emissions. This allows estimation of market effects in the LCA analysis in a broader range of scenarios than shown previously.

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VII. APPENDIX A: GLOBAL ANALYSIS AND DESCRIPTION OF GCAM

A. Additional detail about GCAM's energy system

GCAM's energy system contains representations of fossil resources (coal, oil, gas), uranium, and renewable sources (wind, solar, geothermal, hydro, biomass, and traditional biomass) along with processes that transform these resources to final energy carriers (electricity generation, refining, hydrogen production, gas processing, and district heat), which are ultimately used to deliver goods and services demanded by end use sectors (residential buildings, commercial buildings, transportation, and industry). Each of the sectors in GCAM includes technological detail. For example, the electricity generation sector includes several different technology options to convert coal to electricity such as pulverized coal with and without carbon capture and storage (CCS), coal integrated gasification combined cycle (IGCC) w/ and w/o CCS. In every sector within GCAM, individual technologies compete for market share based on the levelized cost of a technology. The cost of a technology in any period depends on (1) its exogenously specified non-energy cost, (2) its endogenously calculated fuel cost, and (3) any cost of emissions, as determined by the climate policy. The first term, non-energy cost, represents capital, fixed and variable O&M costs incurred over the lifetime of the equipment (except for fuel or electricity costs), expressed per unit of output. For example, the non-energy cost of coal-fired power plant is calculated as the sum of overnight capital cost (amortized using a capital recovery factor and converted to dollars per unit of energy output by applying a capacity factor), fixed and variable operations and maintenance costs. The second term, fuel or electricity cost, depends on the specified efficiency of the technology, which determines the amount of fuel or electricity required to produce each unit of output, as well as the cost of the fuel or electricity. The various data sources and assumptions are documented in the GCAM documentation page (http://jgcri.github.io/gcam-doc/).

The prices of fossil fuels and uranium are calculated endogenously. Fossil fuel resource supply in GCAM is modeled using graded resource supply curves that represent increasing cost of extraction as cumulative extraction increases. Wind and rooftop PV technologies include resource costs that are also calculated from exogenous supply curves that represent marginal costs that increase with deployment, such as long-distance transmission line costs that would be required to produce power from remote wind resources. Utility-scale solar photovoltaic and concentrated solar power technologies are assumed to have constant marginal resource costs regardless of deployment levels.

In GCAM, technology choice is determined by market competition. The market share captured by a technology increases as its costs decline, but GCAM uses a logit model of market competition. This approach is designed to represent decision making among competing options when only some characteristics of the options can be observed and avoids a "winner take all" response. The cost of a technology in any period depends on (1) its exogenously specified non-energy cost, (2) its endogenously calculated fuel cost, and (3) any cost of emissions, as determined by the climate policy. The first term, non-energy cost, represents capital, fixed and variable O&M costs incurred over the lifetime of the equipment (except for fuel or electricity costs), expressed per unit of output. The second term, fuel or electricity cost, depends on the specified efficiency of the technology, which determines the amount of fuel or electricity required to produce each unit of output, as well as the cost of the fuel or electricity. The prices of fossil fuels and uranium are calculated endogenously using resource supply curves that represent increasing cost of extraction as cumulative extraction increases. Wind and rooftop PV technologies include resource costs that are also calculated from exogenous supply curves that represent marginal costs that increase with deployment, such as long-distance transmission line costs that would be required to produce power from remote wind resources. Utility-scale solar photovoltaic and concentrated solar power technologies are assumed to have constant marginal resource costs regardless of deployment levels.

B. Additional detail about scenario design

Table A-1. Detailed assumptions in the S4: Regional Import Limits *scenario*

Region Type		GCAM Regions	High-level target / sanction
Developed countries, natural gas importers with sufficient domestic resources		EU-12, EU-15, Europe_Eastern, Europe_Non_EU	Reduce gross imports to 90% by 2035 and zero by 2040
Developed countries, natural gas importers with low domestic natural gas resources		Japan, South Korea, Taiwan	Maintain current import dependence through 2050
Developing countries, natural gas importers		Brazil, China, India, Pakistan, Southeast Asia, Mexico, South Africa	Maintain current import dependence through 2050
Natural gas exporters		USA, Africa_Eastern, Africa_Northern, Africa_Southern, Africa_Western, Australia_NZ, Canada, Central America and Caribbean, Central Asia, European Free Trade Association, Indonesia, Middle East, South America_Southern, South America_Northern, South Asia, Colombia, Argentina	Reduce gross imports to 90% by 2035 and zero by 2040

Russia		Russia	Same as *S2*

C. Additional GCAM results

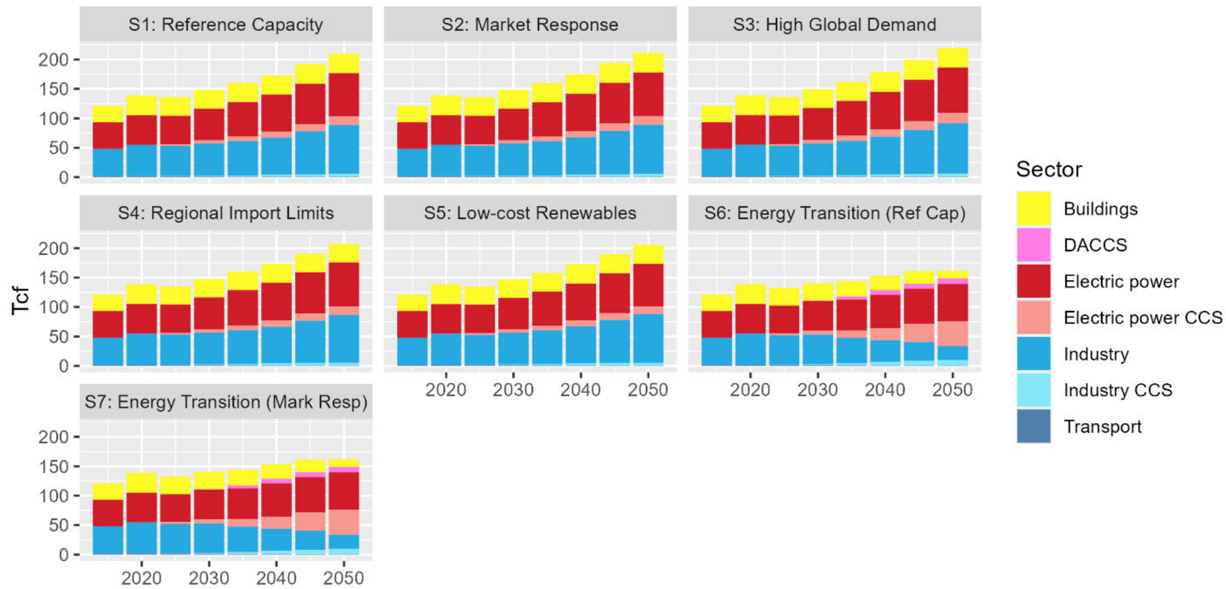

Figure A-1. Global natural gas consumption by sector across all scenarios

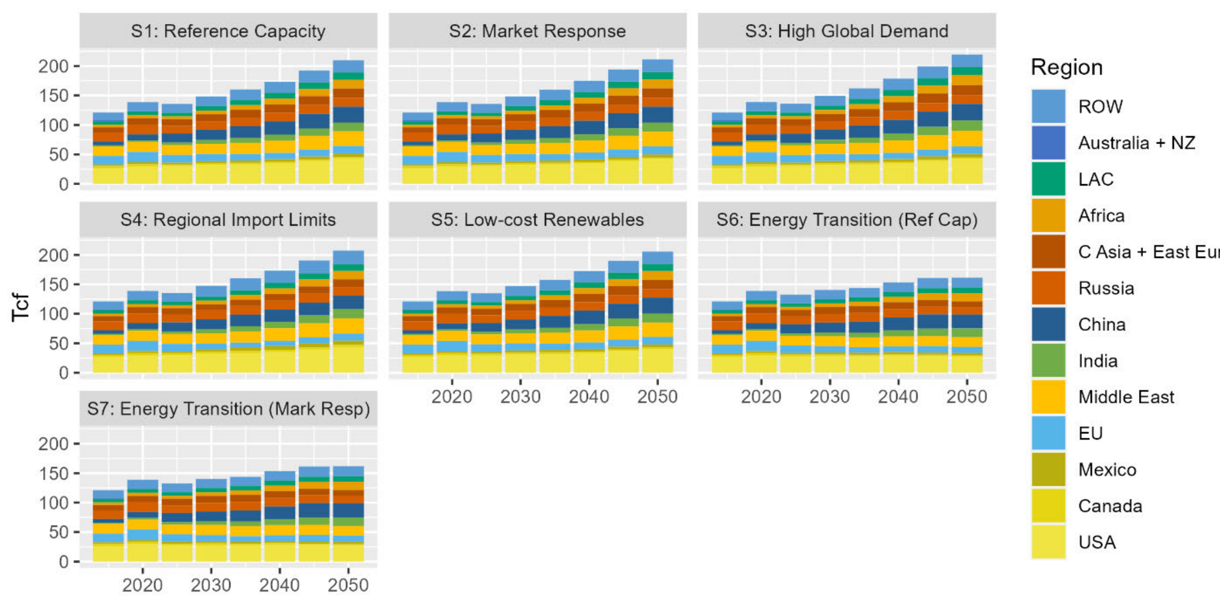

Figure A-2. Global natural gas consumption by region across all scenarios

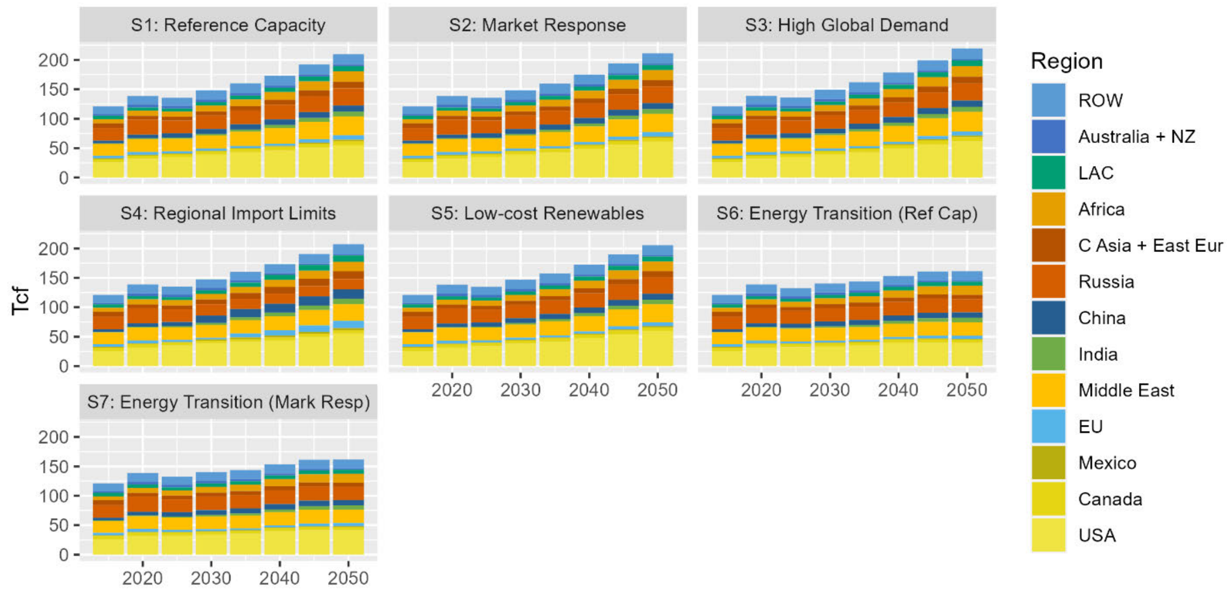

Figure A-3. Global natural gas production by region across all scenarios

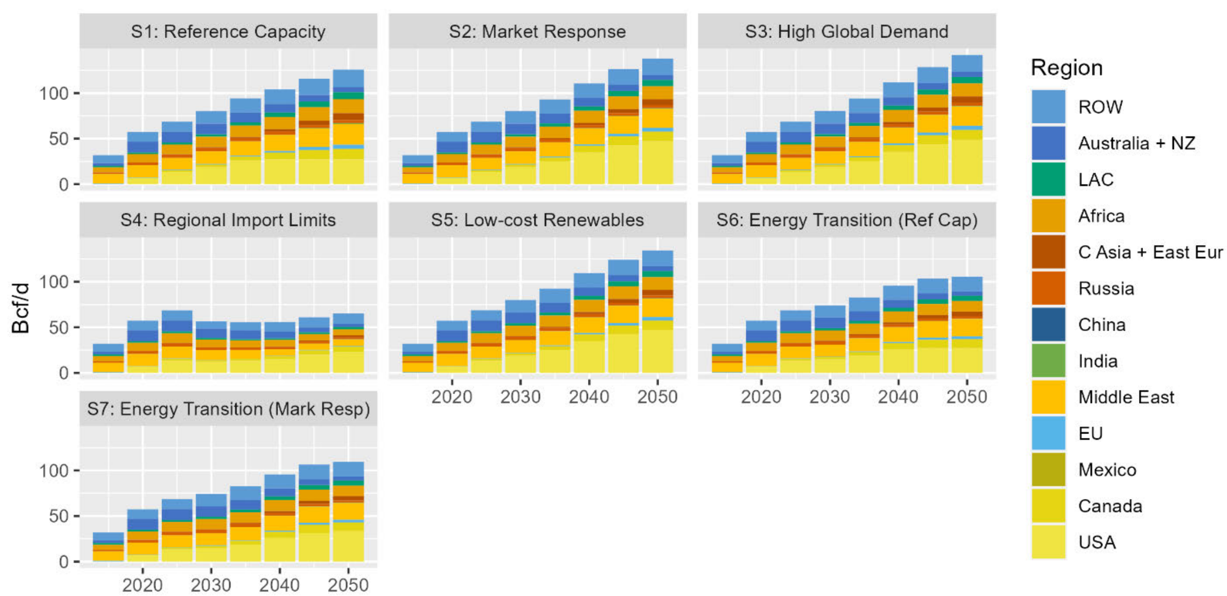

Figure A-4. Global LNG exports by region across all scenarios

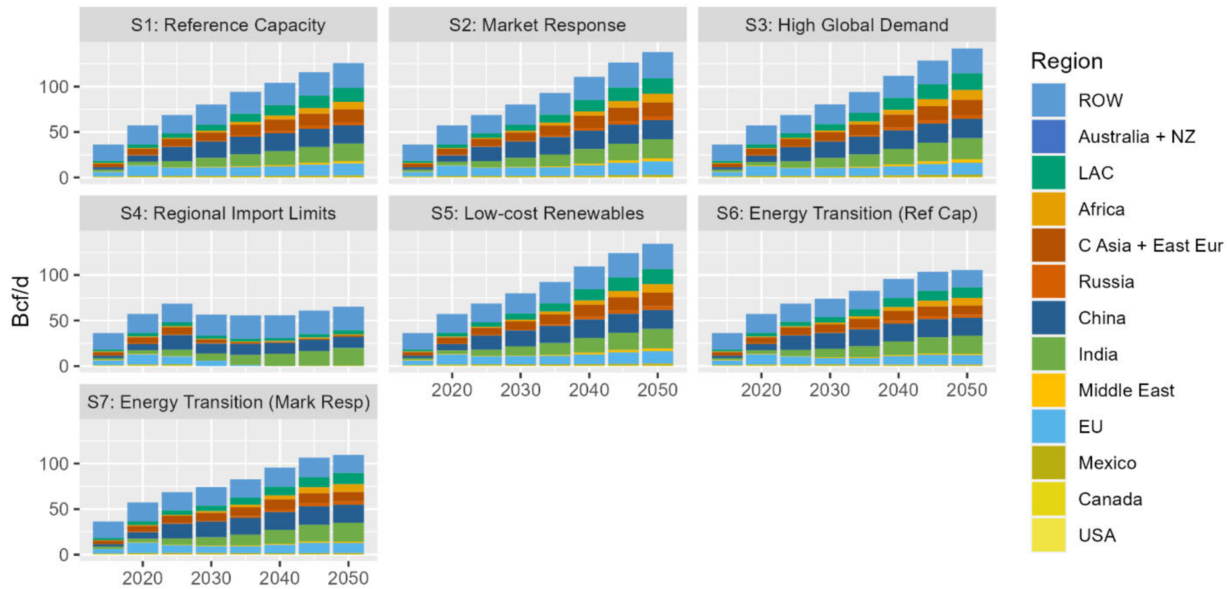

Figure A-5. Global LNG imports by region across all scenarios

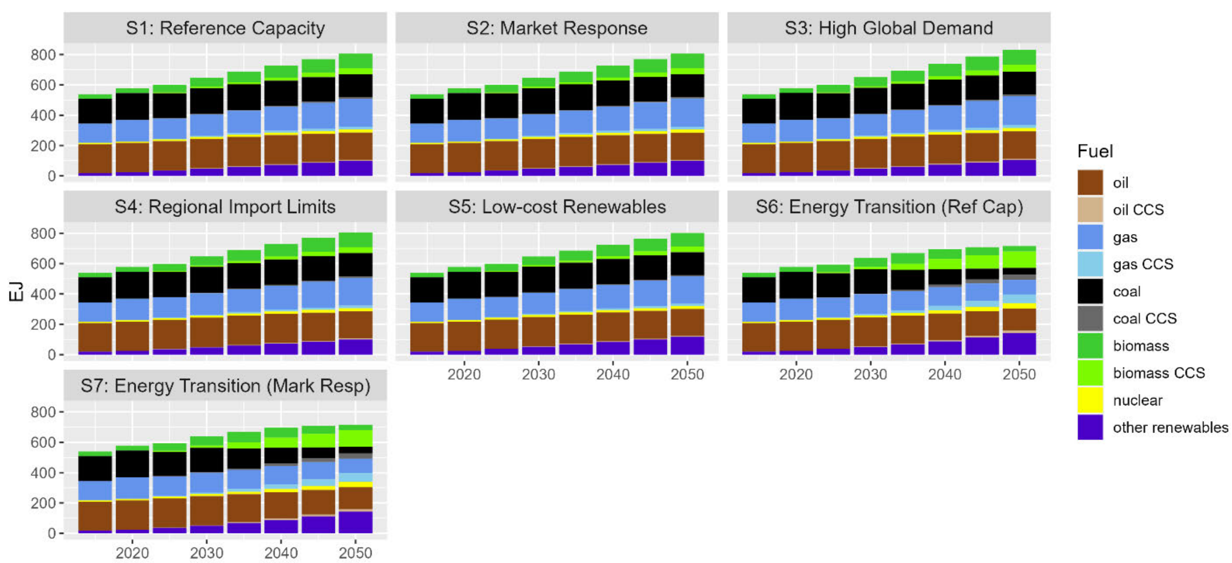

Figure A-6. Global primary energy consumption by fuel across all scenarios

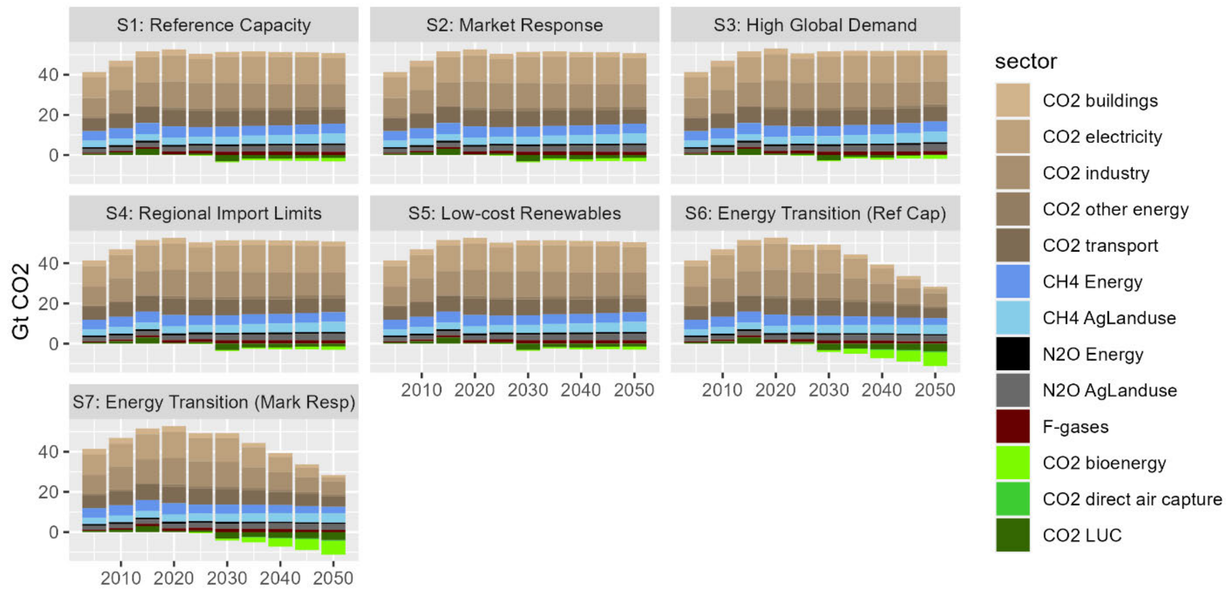

Figure A-7. Global GHG emissions by sector across all scenarios

VIII. APPENDIX B: U.S. ANALYSIS AND DESCRIPTION OF AEO23-NEMS AND FECM-NEMS

A. U.S. Role in Global Natural Gas Market

In Asia most LNG contracts are indexed to crude oil prices due to the lack of regional natural gas trading. Oil has also been historically seen as a direct competitor to natural gas and prices were therefore linked to ensure competitiveness. However, European and U.S. markets have largely shifted away from oil-indexed gas contracts. In Europe, natural gas prices are set at regional trading hubs like the National Balancing Point (NBP) in the United Kingdom or the Title Transfer Facility in the Netherlands. In the United States natural gas prices are based on the Henry Hub benchmark which is determined by domestic supply and demand for natural gas, production levels and pipeline/transportation constraints.

The Henry Hub is increasingly being used as a global benchmark. This is because the U.S. has become a significant exporter of LNG, and many global LNG contracts are now priced relative to Henry Hub rather than oil, which was traditionally the case. This shift has increased the influence of U.S. natural gas production on global prices.

The United States played a significant role in mitigating Europe's energy crisis in 2022, brought on by Russia's reduced gas supplies. U.S. producers operated their liquefaction plants at or above 100% of baseload capacity, exporting double the amount of LNG to Europe in the first three quarters of 2022 compared to all of 2021. This was achieved by diverting shipments originally intended for Asia to Europe, which strained the LNG export value chain and highlighted the need for increased capacity.

In Asia, developing countries grappled with the affordability of natural gas, while developed countries worried about supply reliability, particularly considering geopolitical tensions. Despite having the largest regasification capacity, Asia is projected to continue to experience uncertainty in the natural gas supply. Local natural gas supply has fallen short of the increasing demand. Furthermore, when U.S. LNG was diverted to Europe, developing Asian countries struggled with high price. To offset the natural gas shortage, developing countries in-region had to use alternative fuel source, such as coal and biomass which are higher emitting fuels.

B. Modeling U.S. LNG Exports

AEO23-NEMS and FECM-NEMS have two methods available to calculate LNG export capacity: endogenous and exogenous. There is a switch in the input files that can be toggled to switch between the two methods before executing a run. *S1* uses the EIA AEO23 reference case, which calculates LNG export capacity endogenously; *S2* through *S6* are initialized with exogenous export capacity, which use exogenous LNG export values from the GCAM model for each scenario. Both AEO23-NEMS and FECM-NEMS follow a similar process with only minor differences in a small number of input values. In most cases (including all cases discussed in this report) LNG exports will equal LNG export capacity because the cost to construct capacity is so high that capacity will rarely be left unused once built. Therefore, the following description can be treated as an explanation for how AEO23-NEMS and FECM-NEMS calculate LNG Export volumes.

The algorithm for calculating LNG export capacity endogenously is separated into two steps. In the first step, AEO23-NEMS considers LNG exports from existing or planned LNG export facilities. Beginning with Cheniere's Sabine Pass facility, which started exporting LNG in 2016, AEO23-NEMS runs through a list of export facilities specified in an input file. This list is updated with each version of the AEO; AEO23-NEMS includes existing and planned facilities expected to start or expand production by the end of 2025. For each facility, AEO23-NEMS slowly increases production over the first few months to represent an export facility ramping up to full capacity.

The second step in the endogenous algorithm involves a prediction of future LNG exports. AEO23-NEMS uses a set of exogenous values in an input file to specify how much demand Europe and Asia will have for LNG imports, as well as how much supply of non-U.S. LNG will exist on the market. Then, considering the volume of U.S. LNG exports at a given model year, AEO23-NEMS calculates how the ratio of supply and demand changes over time. This ratio, together with the world oil price, is used to calculate the price at which international customers will purchase U.S. LNG. The purchase price algorithm is constructed in such a way that rises in the oil price, decreases or slowdowns in future LNG supply, or increases in future LNG demand will all increase the purchase price of LNG, and vice-versa. The influence that each factor has on LNG purchase price is controlled by several input parameters.

In addition to a purchase price, AEO23-NEMS calculates the price at which U.S. LNG could be sold for. This "sale price" combines the natural gas Henry Hub price with various costs that represent the stages of preparing pipeline gas for LNG transport (including liquefaction, fuel consumption, shipping, and regasification). AEO23-NEMS then compares the sale price to purchase prices at different destinations and determines a discounted net present value (NPV) of new LNG construction over the subsequent 20 years. Depending on the NPV, AEO23-NEMS will decide to increase LNG export capacity by 0 to 600 Bcf/d. The increase in capacity takes effect after a four year "construction" period and brief "phase-in" period.

The algorithm in AEO23-NEMS to calculate LNG export capacity exogenously is far simpler. A table in an input file lists LNG export capacity by year; these values are used by AEO23-NEMS to set LNG exports for that year. In *S2* through *S6*, various parameters, including LNG export volumes, are calculated by the GCAM model. The LNG export volumes are converted to the correct input format and adopted by AEO23-NEMS as the exogenous LNG export capacity.

C. Additional detail on U.S. Natural Gas Markets

1. Regional Natural gas production

Figure B-1 and Figure B-2 plot onshore natural gas production by region for the first five scenarios and the net-zero scenarios, respectively, in 2025 and 2050. Offshore natural gas production comprises a small portion of the total (<4 % in all scenarios and years) and is omitted from these figures.

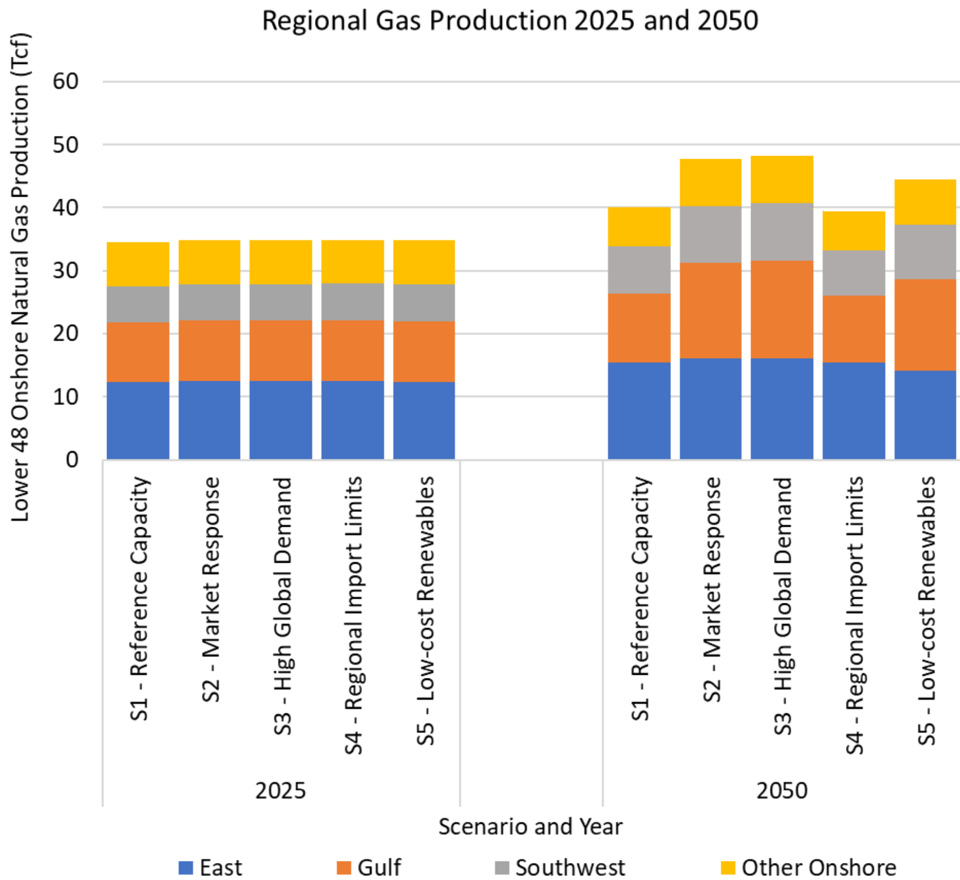

Figure B-1. Regional Gas Production, S1 *through* S5

Natural gas production experiences an upward trend across all scenarios by 2050, equaling or exceeding 39 Tcf. Scenario *S3* exhibits the highest production level at 48 Tcf, influenced by the global demand for natural gas. Expansion is primarily characterized by a significant increase in production in the Gulf region, subsequently followed by the Southwest and the East. Conversely, scenario *S4* sees the lowest natural gas production at 39 Tcf with least production growth in the Gulf region.

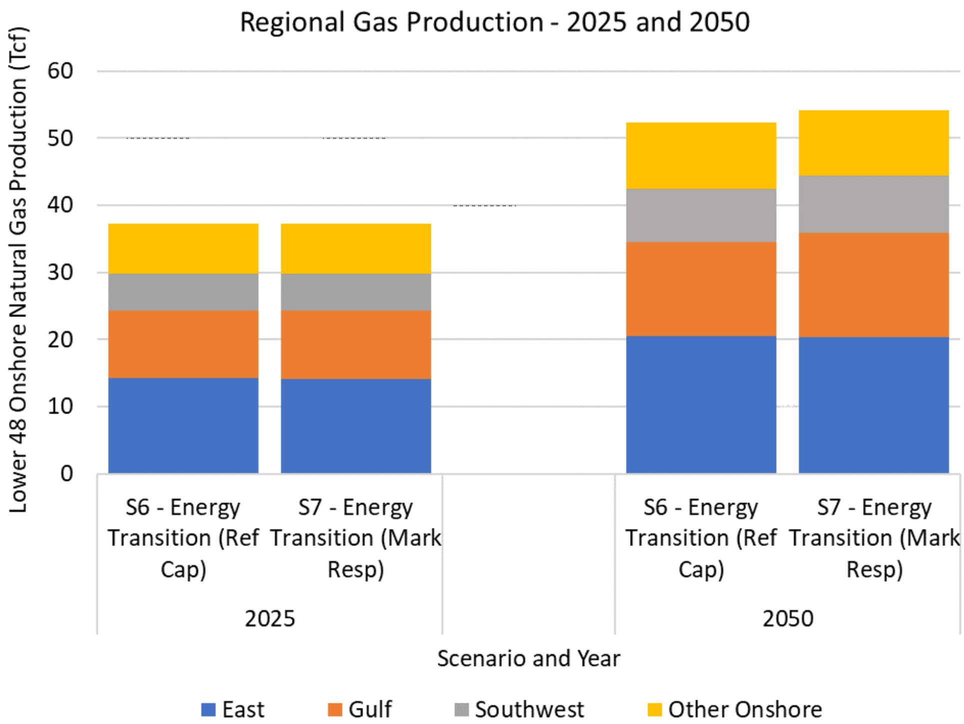

Figure B-2. U.S. Regional gas production in S6 *and* S7

Onshore natural gas production grows significantly from 2025 to 2050 for both net-zero scenarios, rising from 37 Tcf in 2025 to 52 Tcf in *S6* and 54 Tcf in *S7*, respectively, by 2050. The large growth in natural gas production is primarily due to demand from DAC facilities, with only a small increase associated with elevated LNG exports in the *S7* scenario. Natural gas production rises in all regions, with the largest absolute increases coming from the East (6.4 Tcf in *S6* and 6.2 Tcf in *S7*) and Gulf (3.8 Tcf in *S6* and 5.3 Tcf in *S7*) regions and the largest increase by percentage coming from the Southwest (47% in *S6* and 58% in *S7*).

2. Natural gas consumption by economic sector

a) Scenarios 1 through 5

Figure B-3 plots natural gas consumption for electric power, industry, residential use, commercial use, and transportation over time for *S1* through *S5*.

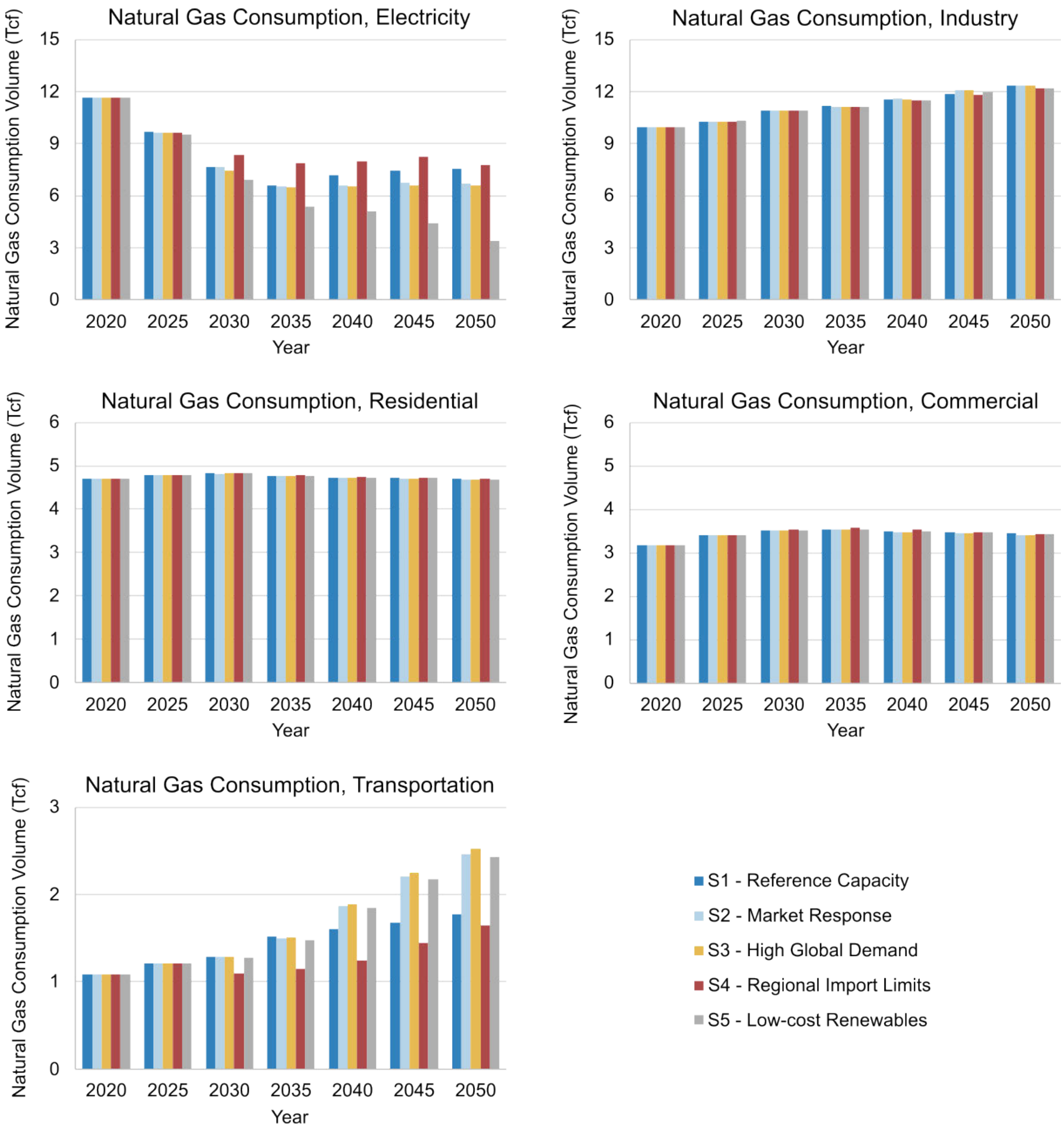

Figure B-3. U.S. natural gas consumption by sector S1 – S5.

Natural gas consumed for electricity is inversely correlated with LNG exports and natural gas prices for *S1*-*S4*. From a starting point of 11.6 Tcf in 2020, the first three scenarios drop to similar consumption volumes of 6.5-6.6 Tcf in 2035 before slightly increasing to 7.6 Tcf (*S1*) or plateauing at 6.7 and 6.6 Tcf (*S2* and *S3*, respectively) in 2050. The increased consumption of natural gas for electricity in *S1* can be explained as a response to price reductions caused by plateauing LNG exports, whereas high prices and exports in *S2* and *S3* lead to a flat consumption trend. *S4* – the scenario with the fewest exports and lowest prices through the first half of the model – exhibits the highest consumption for electricity in 2035 of 7.9 Tcf, which rises and falls slightly to a similar level to *S1* in 2050 (7.8 Tcf). *S5* is again an outlier here, reporting consistently lower natural gas consumption that hits a minimum of 3.4 Tcf in 2050. This trend is a consequence of its low renewable costs reducing the demand for natural gas in the electric sector.

Unlike for electricity, there is no significant difference between scenarios in the rate of natural gas consumption in the industrial, residential, or commercial sectors. Industrial natural gas consumption rises from 9.9 Tcf in 2020 to 12.2-12.4 Tcf in 2050 across the five scenarios; residential consumption remains relatively unchanged at 4.7 Tcf from 2020 to 2050 with some small variations; commercial consumption rises and falls slightly from 3.2 Tcf in 2020 to 3.4 Tcf in 2050.

Natural gas consumed for transportation has a different response to changes in LNG exports, compared with the other consumptions sectors. The transportation category is dominated by pipeline fuel: natural gas consumed to power infrastructure underlying the natural gas supply chain, which includes LNG exports. Increases in natural gas consumption for transportation therefore correlate strongly with the quantity of LNG exports; *S3* exhibits the highest consumption in the transportation sector by 2050, followed by *S2* and *S5*, *S1*, and finally *S4*.

The sector-by-sector changes across the five scenarios end up cancelling each other out for *S1-S4*, leading to nearly identical total natural gas consumption values, as seen in Figure 15. Only *S5*, thanks to its low renewable costs, exhibits a lower overall U.S. natural gas consumption trend.

b) Net-zero Scenarios

Comparisons of *S1* through *S5* with *S6* and *S7* are complicated because of the many significant changes to the energy economy (going from AEO23-NEMS to FECM22-NEMS) that occur to satisfy the net-zero criteria. Relative to *S1*, natural gas consumption values decline across most sectors in *S6* and *S7* but are substantially higher in the industry sector (where DAC consumption is categorized). Figure B-4 plots natural gas consumption for the net-zero cases on a sector-by-sector basis.

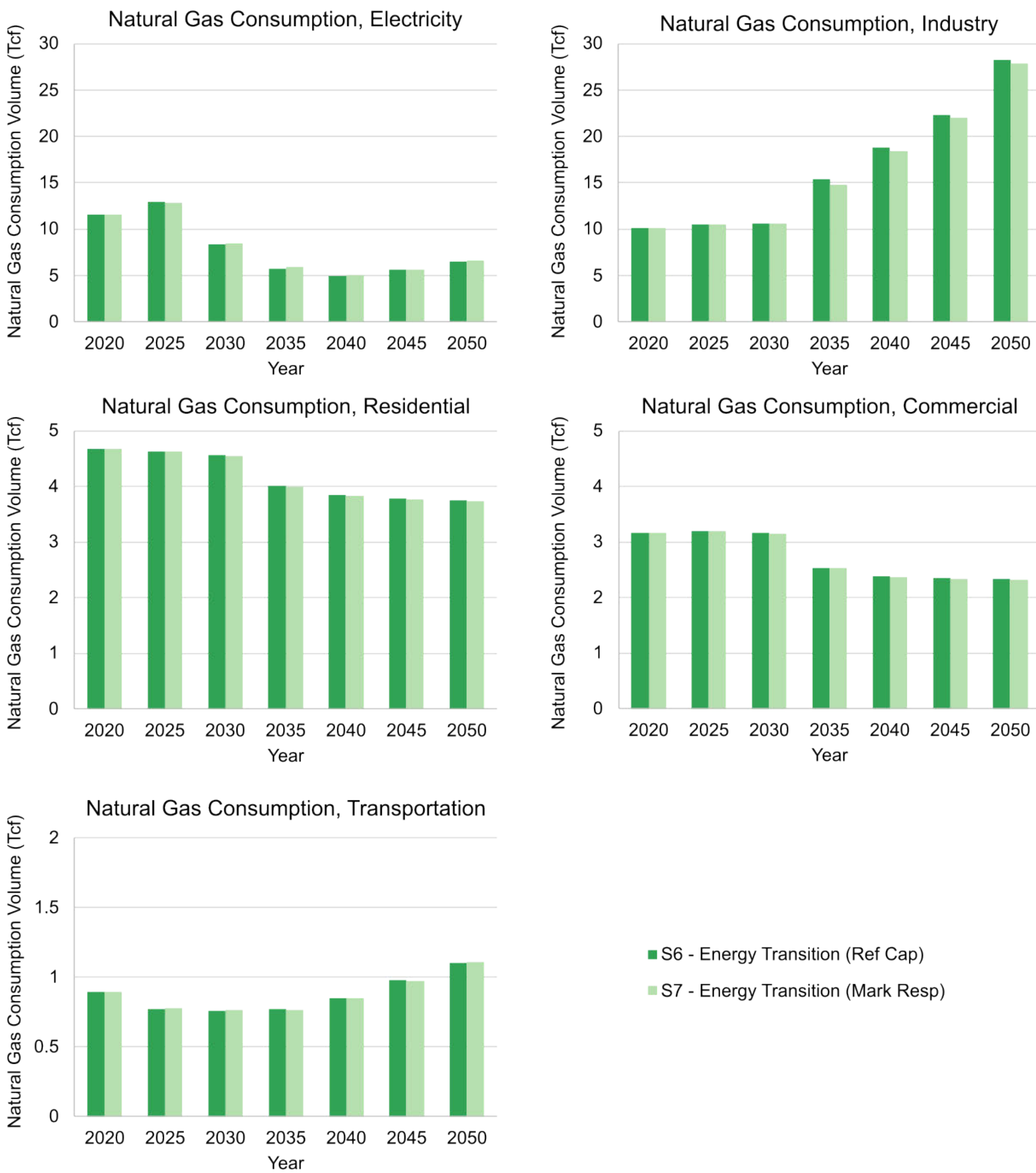

Figure B-4. U.S. natural gas consumption by sector net-zero scenarios

Differences in historical natural gas consumption and subsequent short-term effects cause a difference in natural gas consumption for electricity in 2020 and 2025 between *S6* and *S7* (from the FECM-NEMS model) and *S1* through *S5* (from the AEO23-NEMS model). Similar differences in the historical data exist for all sector-specific consumption values. Volumes of natural gas consumed for electricity track closely between the two net-zero cases across most of the modeling years, ranging from 5.7 to 5.9 Tcf in 2035 for *S6* and *S7*, respectively, and rising in later years to 6.5 Tcf and 6.6 Tcf. *S6* reports a lower natural gas consumption value in 2050 than *S1* (7.6 Tcf), but the corresponding result for *S7* is fairly close to *S2* (6.7 Tcf).

Industry-sector natural gas consumption exhibits the largest change between the net-zero scenarios and *S1* through *S5*, thanks to the strong influence of DAC. Whereas industry consumption of natural gas in *S1* and *S2* both increase from 9.9 Tcf to 12.3 Tcf over the 50 model years, the net-zero scenarios diverge after 2030 and grow rapidly to 28.2 and 27.8 Tcf for *S6* and *S7*, respectively, by 2050. The difference in consumption values is consistent with the natural gas consumption for DAC, which is plotted below in Figure B-5.

Residential- and commercial-sector natural gas consumption follow similar behavior. These values decrease in both net-zero scenarios across the model years from 4.7 to 3.7 Tcf (residential) and from 3.2 to 2.3 Tcf (commercial). By comparison, both *S1* and *S2* have static or slightly increasing trends, with both reporting 4.7 Tcf in 2020 and 2050 for residential consumption and 3.2 to 3.4 Tcf from 2020 to 2050 for commercial consumption.

Transportation is the smallest of the five sectors in terms of natural gas consumption volumes, and calculation differences between AEO23-NEMS and FECM-NEMS lead to large impacts on the consumption values. As a result, these values are not directly comparable between the three scenarios. *S6* and *S7* have nearly identical volumes of natural gas consumed for the transportation sector, varying from 0.9 Tcf in 2020 to 0.8 Tcf in 2035 and 1.1 Tcf in 2050. By comparison, *S1* and *S2* report consistently higher natural gas consumption for transportation across the model years, ranging from 1.1 Tcf in 2020 to 1.8 and 2.3 Tcf, respectively, in 2050.

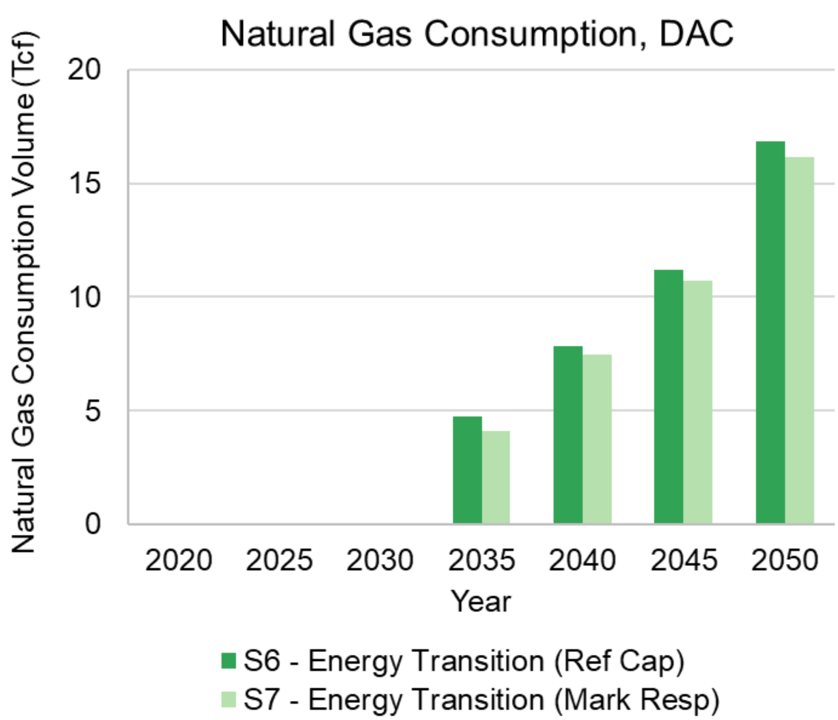

Figure B-5. Natural gas consumed for DAC, net-zero scenarios

DAC is the main technology used by FECM-NEMS to meet the CO_2 cap and by 2050 is responsible for removing 1930 MMT CO_2 per year in *S6* and 1850 MMT CO_2 per year in *S7*. A considerable amount of natural gas is consumed to support these levels of DAC: 16.8 Tcf and 16.2 Tcf in 2050 for *S6* and *S7*, respectively. More detail on CO_2 removal technologies in FECM-NEMS is given in Section I.D below.

In conclusion, even though four out of the five sectors exhibit decreases when comparing natural gas consumption in the net-zero scenarios to *S1* and *S2*, the strong increases in the industrial sector (mainly from increases in DAC) cause overall U.S. natural gas consumption to be significantly higher by 2050 in *S6* and *S7*. There is minimal difference between the *S6* and *S7* results, suggesting that the differences in LNG exports between the net-zero scenarios play a limited role in altering natural gas consumptions trends.

D. Usage of CO_2 removal technologies in FECM-NEMS

CO_2 removals in FECM-NEMS are driven by three technologies: production of hydrogen with sequestered biomass, BECCS, and DAC. Figure B-6 plots CO_2 removals for each technology and scenario by year.

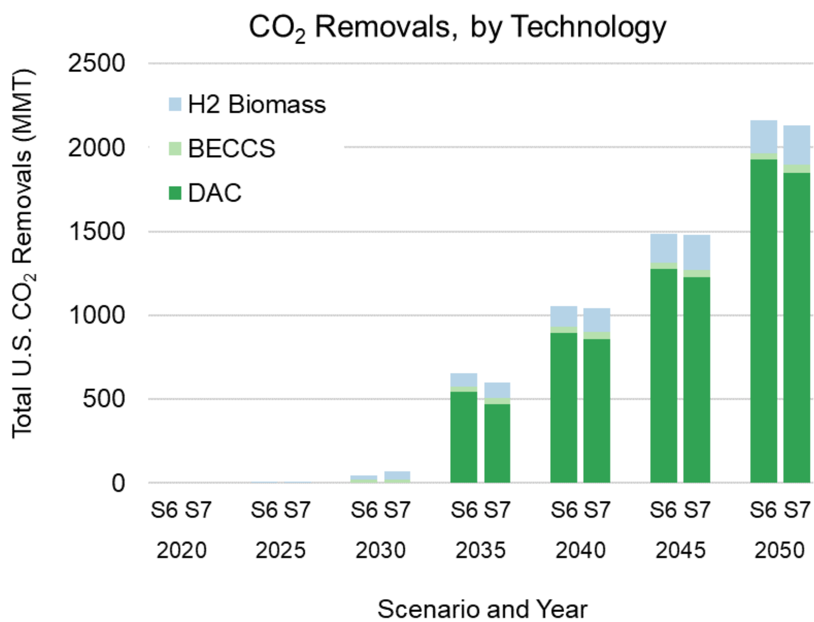

Figure B-6. U.S. CO_2 emissions and removals, net-zero scenarios

DAC is the most widely used in both net-zero scenarios and scales up rapidly after 2030 to account for 1930 MMT CO_2 removed in *S6* and 1850 MMT CO_2 removed in *S7* (89% and 87% of total removals, respectively) by 2050. H2 biomass and BECCS see significantly less adoption by 2050 in both scenarios; the former reaches 200 (9% of total) and 240 (11% of total) MMT CO_2 removed in *S6* and *S7*, respectively, whereas the later reaches approximately 40 MMT CO_2 removed in both scenarios (2% of total removals).

FECM-NEMS relies on two sets of DAC technology assumptions: “grid”, and “NG only,” derived from the literature using updated cost and performance data from FECM.[16] Both use natural gas to power the capture process; DAC-grid offsets some of the natural gas demand by using electricity as well. lists the specific technical assumptions underlying the two DAC options.

Table B-1. DAC technology assumptions in FECM-NEMS

	Capex, \$/ton-year	CRF	Capex, \$/ton	Opex, \$/ton	Electricity demand, kwhr/ton	Natural gas demand, MMBtu/ton
Grid	\$1,300	7.1%	\$112	\$71	450	8.75
NG Only	\$1,500	7.1%	\$129	\$83.6	0	9.27

The effect of DAC on natural gas markets in *S6* and *S7* can be seen in the rapid growth of total natural gas consumption (Figure 16) and subsequent rise in natural gas prices (Figure 17). By 2050, natural gas consumption equals 16.8 Tcf and 16.2 Tcf for *S6*, and *S7*, respectively, reaching natural gas prices of \$5.90 2022/Mcf and \$5.77 2022/Mcf.

FECM-NEMS models the deployment of carbon removal technologies by determining a CO_2 price that represents the market equilibrium cost to capture and abate CO_2 emissions. FECM-NEMS adjusts the CO_2 price in accordance with the imposed carbon cap (plotted in Figure 1) to ensure that the correct number of CO_2 emissions are abated each year. The CO_2 price is plotted in Figure B-7.

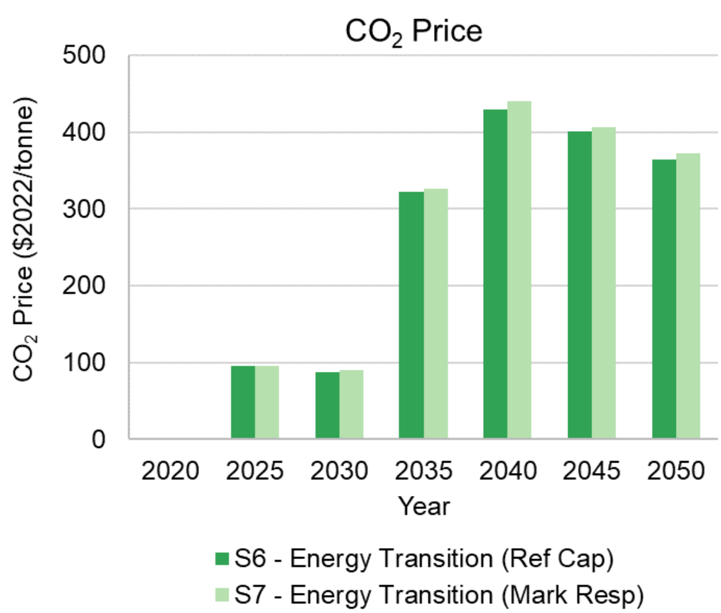

Figure B-7. U.S. CO_2 price, net-zero scenarios

[16] National Academies of Sciences, Engineering, and Medicine. (2019). Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. Washington, DC: The National Academies Press. https://doi.org/10.17226/25259.

The implied CO_2 price rises to \$87-\$96/tonne CO_2 by 2030. The lower price during the first ten years reflects the cost of electrification and fuel switching from fossil to non-fossil sources throughout the energy system, reducing overall CO_2 emissions and satisfying the carbon cap. While emissions continue to decline after 2030, the rate of decline slows; most of the progress towards meeting the carbon cap after 2030 comes in the form of increased carbon removals. The implied CO_2 price climbs rapidly to \$429/tonne CO_2 in *S6* and \$440/tonne CO_2 in *S7* by 2040 as CO_2 removal technologies (primarily DAC) are brought online to satisfy the carbon cap and the subsidies for CO_2 sequestration expire. The rate of emissions reduction slows further from 2040 to 2050, with removals making up a greater portion of the net-decrease in CO_2 emissions. The CO_2 price in these last ten years is therefore dominated by the price of CO_2 removal technologies. It decreases to \$364/tonne CO_2 in *S6* and \$372/tonne CO_2 in *S7* by 2040, reflecting technological improvements to the CO_2 removal processes.

IX. Appendix C: LCA Analysis and Description of Model

From: Francisco De La Chesnaye
Sent: Wed, 6 Sep 2023 18:57:55 +0000
To: Curry, Thomas; Sweeney, Amy
Cc: Iyer, Gokul; Scott Matthews; Jamieson, Matthew B.; Whitman, Peter C; Skone, Timothy
Subject: [EXTERNAL] RE: LNG Export Report
Attachments: DOE_FECM_LNG_Analysis_Report_FINAL_REVIEW_05Sep23_V2.docx
Importance: High

DRAFT – DELIBERATIVE – PRE-DECISIONAL

Tom,

We have corrected the problems with figure refences and page numbering. We also substituted Henry Hub prices in the final summary table and edited the discussion on carbon prices as discussed.
We believe covers everything.

Please see V2 of the Final Review Draft.

Bets, Paco

From: Curry, Thomas <thomas.curry@hq.doe.gov>
Sent: Wednesday, September 6, 2023 11:08 AM
To: Francisco De La Chesnaye <francisco.delachesnaye@onlocationinc.com>; Sweeney, Amy <amy.sweeney@hq.doe.gov>
Cc: Iyer, Gokul C <gokul.iyer@pnnl.gov>; Scott Matthews <scott.matthews@keylogic.com>; Jamieson, Matthew B. <matthew.jamieson@netl.doe.gov>; Peter Whitman <peter.whitman@onlocationinc.com>; Skone, Timothy <timothy.skone@hq.doe.gov>
Subject: RE: LNG Export Report

DRAFT – DELIBERATIVE – PRE-DECISIONAL

Thanks all for the quick work on this. I gave it a quick scan and wanted to flag two issues:

- Can you check the formatting associated with the figures on pages 22-27 (figures 4-6)? It looks like some of text got pulled into the title on page 24 and there is an errant “figure 6” in text on page 25.
- We like the summary table in the conclusion but were surprised that residential prices were included for S6-S7. Are those discussed anywhere else in the document? I didn’t see them on a quick review. If we are going to have them in the table, we will need to explain them. For this

draft, can you include a note at the bottom of the table saying that additional context for S6-S7 residential prices is being developed and will be included in a subsequent draft?

Tom

From: Francisco De La Chesnaye <francisco.delachesnaye@onlocationinc.com>
Sent: Tuesday, September 5, 2023 10:06 PM
To: Curry, Thomas <thomas.curry@hq.doe.gov>; Sweeney, Amy <amy.sweeney@hq.doe.gov>
Cc: Iyer, Gokul <gokul.iyer@pnnl.gov>; Scott Matthews <scott.matthews@keylogic.com>; Jamieson, Matthew B. <matthew.jamieson@netl.doe.gov>; Whitman, Peter C <peter.whitman@onlocationinc.com>; Skone, Timothy <timothy.skone@hq.doe.gov>
Subject: [EXTERNAL] RE: LNG Export Report
Importance: High

DRAFT – DELIBERATIVE – PRE-DECISIONAL

Amy and Tom,

The combined team from PNNL, OnLocation, and NETL are pleased to submit the FINAL REVIEW DRAFT of the attached report "ENERGY, ECONOMIC, AND ENVIRONMENTAL ASSESSMENT OF U.S. LNG EXPORTS".

We look forward to successfully completing the FINAL Deliverable soon.

Best, Paco

Francisco De La Chesnaye | **Vice President**
m: (b) (6) | onlocationinc.com

OnLocation
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From: Curry, Thomas <thomas.curry@hq.doe.gov>
Sent: Tuesday, September 5, 2023 11:27 AM
To: Francisco De La Chesnaye <francisco.delachesnaye@onlocationinc.com>
Cc: Iyer, Gokul C <gokul.iyer@pnnl.gov>; Scott Matthews <scott.matthews@keylogic.com>; Jamieson, Matthew B. <matthew.jamieson@netl.doe.gov>; Peter Whitman <peter.whitman@onlocationinc.com>; Daniel Hatchell <daniel.hatchell@onlocationinc.com>; Jasmine Greene <jasmine.greene@onlocationinc.com>; Sweeney, Amy <amy.sweeney@hq.doe.gov>
Subject: RE: LNG Export Report

Great! Thanks all for your work over the weekend. We very much appreciate it.

Tom

From: Francisco De La Chesnaye <francisco.delachesnaye@onlocationinc.com>
Sent: Tuesday, September 5, 2023 10:46 AM
To: Curry, Thomas <thomas.curry@hq.doe.gov>
Cc: Iyer, Gokul <gokul.iyer@pnnl.gov>; Scott Matthews <scott.matthews@keylogic.com>; Jamieson, Matthew B. <matthew.jamieson@netl.doe.gov>; Whitman, Peter C <peter.whitman@onlocationinc.com>; Daniel Hatchell <daniel.hatchell@onlocationinc.com>; Jasmine Greene <jasmine.greene@onlocationinc.com>
Subject: [EXTERNAL] LNG Export Report

Tom,

We worked over the weekend to address all tenoning comments and complete the report. It is now going through a final technical edit review. We are planning to finish today by COB. I'll give you another status update later today.

Best, Paco

Get Outlook for iOS

Francisco De La Chesnaye | Vice President
m: (b) (6) | onlocationinc.com

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ENERGY, ECONOMIC, AND ENVIRONMENTAL ASSESSMENT OF U.S. LNG EXPORTS

FINAL REVIEW DRAFT September 5, 2023

Prepared for:

Office of Resource Sustainability

U.S. DEPARTMENT OF ENERGY | Fossil Energy and Carbon Management

Prepared by:

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Acronyms and Abbreviations

AEO	Annual Energy Outlook
BECCS	Bioenergy with carbon capture and storage
Bcf	Billion cubic feet
BIL	Bipartisan Infrastructure Law
BP	British Petroleum
BTU	British Thermal Unit
CAFE	Corporate Average Fuel Economy
CCS	Carbon capture and storage
CCUS	Carbon capture, utilization, and storage
CDR	Carbon dioxide removal
CH_4	Methane
CO_2	Carbon dioxide
DAC	Direct air capture
DOE	Department of Energy
EIA	Energy Information Administration
EJ	Exajoule (10^{18} joules)
EPA	Environmental Protection Agency
FECM	Fossil Energy and Carbon Management
GHG	Greenhouse gas
GCAM	Global Change Analysis Model
GNGM	Global Natural Gas Model
Gt	Gigaton
GWP	Global warming potential
HMM	Hydrogen Market Module
ITC	Investment tax credit
IRA	Inflation Reduction Act
Kwhr	Kilowatt-hour

LHV	Lower heating value
LNG	Liquefied natural gas
LULUCF	Land use, land use change, and forestry
MAF	Market Adjustment Factor
Mcf	Million cubic feet
MMT	Million metric Tons
NERA	NERA Economic Consulting
NEMS	National Energy Modeling System
NETL	National Energy Technology Laboratory
NGA	Natural Gas Act
NGP	Natural gas processing
NHTSA	National Highway Traffic Safety Administration
NREL	National Renewable Energy Laboratory
N2O	Nitrous oxide
OPEX	Operating Expenses
PNNL	Pacific Northwest National Laboratory
PTC	Production tax credit
S&P	Standard & Poor's
Tcf	Trillion cubic feet
Tg	Teragram (10^{12} grams)

I. EXECUTIVE SUMMARY

The Department of Energy (DOE) is responsible for authorizing exports of U.S. natural gas, including liquefied natural gas (LNG), to foreign countries pursuant to section 3 of the Natural Gas Act (NGA), 15 U.S.C. 717b. Under the NGA provisions, applications requesting authority for the import or export of natural gas, including LNG, from and to a nation with which there is in effect a free trade agreement (FTA) requiring national treatment for trade in natural gas, and/or the import of LNG from other international sources, are deemed consistent with the public interest and granted without modification or delay. For Authorizations relating to those countries with which the United States does not have an FTA requiring national treatment trade in natural gas and with which trade is not prohibited by U.S. law or policy, then pursuant to Section 3(a) of the NGA DOE is required to grant a permit to export domestically produced natural gas unless it finds that such action is not consistent with the public interest.

To inform its Public Interest determination, since 2012, the Office of Fossil Energy and Carbon Management (DOE-FECM) and its predecessor, the Office of Fossil Energy, previously commissioned five studies to assess the effects of different levels of LNG exports on the U.S. economy and energy markets. This sixth updated study, like the previous ones, served as an input to be considered in the evaluation of applications to export LNG from the United States under Section 3 of the NGA.

The purpose of this study was to examine the potential global and U.S. energy system and greenhouse gas (GHG) emissions implications of a wide range of economic levels of U.S. LNG exports. The study was comprised of three coordinated analyses: 1) **a Global Analysis** to explore a wide range of scenarios of U.S. LNG exports under alternative assumptions about future socioeconomic growth, regional preferences for domestically produced natural gas, pace of technological change in competing technologies (e.g. renewables), and countries' announced GHG emissions pledges and policies; 2) **a U.S. Domestic Analysis** of the implications of the various U.S. LNG export levels derived from the Global Analysis for the supply and demand of natural gas within the U.S. and the U.S. economy; and 3) **a Life Cycle Analysis** to examine the life cycle emissions implications of the various levels of U.S. LNG exports derived from the Domestic and Global analyses.

As part of the **Global Analysis**, we explored seven scenarios spanning a range of plausible U.S. LNG export outcomes by 2050 using the Pacific Northwest National Laboratory's Global Change Analysis Model (GCAM). GCAM is a model of the global energy, economy, agriculture, land use, water, and climate systems with regional detail in 32 geopolitical regions. This includes major economies as single-country regions (e.g., U.S., Canada, China, India, Russia). The seven scenarios explored in this study are shown in Table ES-1.

Table ES-1. Scenario Descriptions

Scenario	Description	U.S. LNG Export Volumes (Bcf/d)
***S1*: Reference Exports**	Reference scenario in which U.S. LNG exports follow EIA's 2023 Annual Energy Outlook (AEO). Incorporates U.S. policy assumptions (including the 2022 Inflation Reduction Act). Assumes existing policies and measures, globally.	Grows to 27.34 Bcf/d by 2050
***S2*: Market Response**	Assumes policies consistent with *S1*, but U.S. LNG exports are determined by global market equilibrium.	GCAM Market Response
***S3*: High Global Demand**	Same assumptions as *S2*, U.S. LNG exports determined by global market equilibrium, but assumes higher population growth outside of the U.S.	
***S4*: Regional Import Limits**	Same assumptions as *S2*, U.S. LNG exports determined by global market equilibrium, but includes constraints on importing and exporting natural gas with a global focus to maximize use of domestic gas.	
***S5*: Low-cost Renewables**	Same assumptions as *S2*, U.S. LNG exports determined by global market equilibrium, but assumes lower capital costs for renewable energy technologies.	
***S6*: Energy Transition (Ref Exp)**	Assumes an emissions pathway consistent with a global temperature change of 1.5°C by end of century. Countries' emissions are constrained to announced GHG pledges, including the U.S. following a path to net-zero GHG emissions by 2050. NEMS follows CO_2 emissions constraint from GCAM. U.S. LNG exports are limited to the values from the AEO 2023 Reference scenario.	Grows to 27.34 Bcf/d by 2050
***S7*: Energy Transition**	Same emissions pathway assumptions as *S6*, but U.S. LNG exports are determined by global market equilibrium.	GCAM Market Response

All of the scenarios include representations of the 2022 Inflation Reduction Act (IRA) in the U.S. and existing emission policies in the rest of the world. The scenarios also include a constraint on Russian exports. The modeling and analysis for this report was completed by August 2023.

The **U.S. domestic analysis** was conducted using the National Energy Modeling System (NEMS). U.S. LNG exports (for all scenarios except *S1*) and CO_2 emissions (in scenarios *S6* and *S7*) used in NEMS were harmonized to values from GCAM. NEMS was then used to explore the implications of the seven global scenarios for domestic gas prices, the energy system, and the macro-economy within the U.S.

Finally, the **Life Cycle Analysis** of natural gas used for export was enhanced by comparing the results provided from the domestic and global analyses to previously completed NETL studies of the natural gas life cycle. GCAM results were assessed against existing DOE life cycle studies of natural gas and aligned to have the same GHG intensity for the purposes of consistency. The main results of this analysis were a series of estimated market adjustment factors that supplement the previous life cycle analyses and better represent the total global change in emissions per unit of U.S. LNG exported.

A number of key insights emerged from this study:

1. Across all modeled scenarios, U.S. LNG exports and U.S. natural gas production increase beyond current levels-through 2050 (Figure ES-1).
2. Global natural gas consumption increases only slightly (<1 percent) under a scenario with increased availability of U.S. natural gas in the global market that reflects economically driven LNG export levels (S2) compared to the reference scenario (S1). The majority of the additional U.S. natural gas substitutes for other global sources of natural gas.
3. U.S. natural gas prices as measured at the Henry Hub increase modestly when comparing a scenario that reflects global market demand for exports (S2) to the reference scenario (S1). Across those scenarios, 2050 Henry Hub prices were projected to increase from $3.61/Mcf to $4.74/Mcf, both of which are less than the reference 2050 price expected in the most recent study[5] commissioned on the economic impacts from U.S. LNG exports in 2018.
4. U.S. residential prices were projected to be 4% higher in 2050 when comparing a scenario that reflects global market demand for exports (S2) to the reference scenario (S1).
5. The value of industrial shipments remains essentially unchanged (increasing less than 0.1% by 2050) under a scenario that reflects global market demand for exports *(S2)* compared to the reference scenario *(S1).* The impact of increased LNG exports on GDP is essentially flat: positive by less than 0.1% across scenarios through 2045 while all changes are within 0.3% in 2050.
6. Global and U.S. GHG emissions do not change appreciably across the scenarios with current climate policy assumptions (*S2 to S5*) even though these scenarios vary widely in terms of U.S. LNG export outcomes. In these scenarios, global emissions range from 47.5-50.3 $GtCO_2e$ and U.S. emissions range from 4.3-4.6 $GtCO_2e$ while U.S. LNG exports range from 23 to 47 Bcf/day.
7. The induced global market effects per unit of increased LNG exports in a scenario that reflects global market demand for exports (S2) compared to the reference scenario (S1) are equivalent to an overall reduction in GHG emissions that is about 70% of the estimated upstream emissions associated with production through delivery of the natural gas through the transmission system in the U.S.
8. Relative to the other scenarios, the scenarios in which countries are assumed to achieve GHG emissions pledges and pursue ambitious GHG mitigation policies (*S6* and *S7*) are characterized

by lower energy consumption; lower fossil fuel consumption without carbon capture, utilization, and storage (CCUS); higher deployment of renewables and fossil fuels and biomass with CCUS; and higher deployment of carbon dioxide removal strategies.

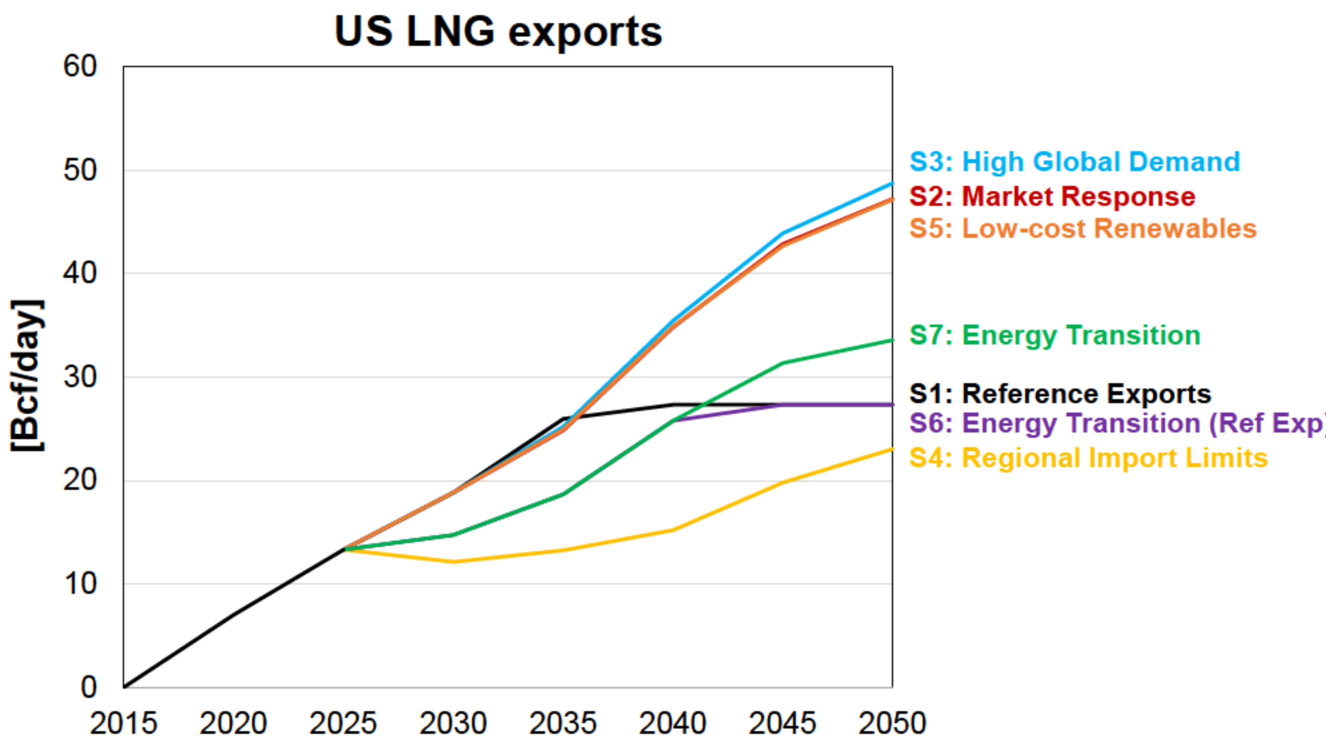

Figure ES-1. U.S. LNG exports across the scenarios explored in this study. Note that the U.S. LNG export outcomes for S2 and S5 were very close to each other.

II. Background on LNG Export Studies Commissioned by Department of Energy

Since 2012, the Office of Fossil Energy and Carbon Management (DOE-FECM) and its predecessor, the Office of Fossil Energy, previously commissioned five studies on the effects of increased LNG exports on the U.S. economy and energy markets. The previous studies of the impact of LNG exports are listed in Table 1.

The EIA 2012 study examined four different levels of exports across four domestic natural gas supply scenarios for a total of 16 scenarios. Exports ranged from 6 to 12 Bcf/day with varying trajectories. The supply scenarios were: AEO2011 Reference, High Shale Estimated Ultimate Recovery (EUR), the Low Shale EUR, and High Economic Growth. Key results demonstrate that natural gas markets balanced the increased exports through increased supply and prices and a reduction in demand for power generation and in the other sectors.

The NERA 2012 report used NERA's Global Natural Gas Model (GNGM) and NewERA energy-economy model to look at the domestic economic effects of LNG exports. Building upon the EIA 2012 study, the NERA 2012 report examined sixteen scenarios from the earlier study using different assumptions on natural gas supply and demand. The report additionally included scenarios examining the global demand for U.S. LNG exports and the macroeconomic impact of increased LNG exports on the economy.

The EIA 2014 study included updated export scenarios from 12 to 20 Bcf/day and domestic natural gas supply scenarios from AEO2014: the Low and High Oil and Gas Resource scenarios, High Economic Growth, and Accelerated Coal and Nuclear Retirements. Increased exports led to increased natural gas production and prices relative to respective base scenarios, though also higher primary energy consumption and energy-related CO_2 emissions.

Table 1. Previous Studies

Report Name	Organization	Short Name
Effect of Increased Natural Gas Exports on Domestic Energy Markets[1]	EIA	EIA 2012
Effect of Increased Natural Gas Exports on Domestic Energy Markets[2]	NERA	NERA 2012
Effect of Increased Levels of Liquefied Natural Gas Exports on U.S. Energy Market[3]	EIA	EIA 2014

[1] U.S. EIA. (2012). Effects of Increased Natural Gas Exports on Domestic Energy Markets. Available at: https://energy.gov/sites/prod/files/2013/04/f0/fe_eia_lng.pdf
[2] NERA Economic Consulting. (2012). Macroeconomic Impacts of LNG Exports from the United States. Available at: https://energy.gov/sites/prod/files/2013/04/f0/nera_lng_report.pdf
[3] U.S. EIA. (2014). Effect of Increased Levels of Liquefied Natural Gas Exports on U.S. Energy Markets. Available at: https://www.eia.gov/analysis/requests/fe/pdf/lng.pdf

Report Name	Organization	Short Name
The Macroeconomic Impact of Increasing U.S. LNG Exports[4]	Baker Institute/ Oxford Economics	Baker 2018
Macroeconomic Outcomes of Market Determined Levels of U.S. LNG Exports[5]	NERA	NERA 2018

The Baker 2015 study examined U.S. LNG exports of 12 and 20 Bcf/day. Two models were used: an international natural gas model (from the Baker institute) and a global economic model from Oxford Economics. This study outlined the international conditions that could result in a market for over 20 Bcf/day of LNG exports and examined in the impact on the U.S. economy of scenarios with 12 and 20 Bcf/day of LNG exports and with low gas resource recovery, high gas resource recovery and high demand.

The NERA 2018 study again used NERA's Global Natural Gas Model and the NewERA energy-economy model to look at the domestic economic effects of LNG exports. LNG exports were determined by the model for each scenario. The study included 54 different scenarios capturing a broad range of domestic and international gas supply and demand conditions, and probabilities on the likelihood of each of the 54 export scenarios. In general, high levels of LNG exports corresponded to high oil and gas supply but higher prices. Since approximately 80% of the exports resulted from increased production rather than decreased demand, the general economic impact was positive across the scenarios. The report concluded that the impact on energy-sensitive industries was very small while increased investment raised GDP.

[4] Cooper, A., Kleiman, M., Livermore, S., & Medlock III, K. B. (2015). The Macroeconomic Impact of Increasing US LNG Exports. Available at:
https://energy.gov/sites/prod/files/2015/12/f27/20151113_macro_impact_of_lng_exports_0.pdf

[5] NERA Economic Consulting. (2018). Macroeconomic Outcomes of Market Determined Levels of U.S. LNG Exports. Available at:
https://www.energy.gov/sites/prod/files/2018/06/f52/Macroeconomic%20LNG%20Export%20Study%202018.pdf

III. INTRODUCTION

A. Project Background

The Department of Energy (DOE) is responsible for authorizing exports of natural gas, including LNG, to foreign countries pursuant to Section 3 of the Natural Gas Act (NGA), 15 U.S.C. 717b. Under the NGA provisions, applications requesting authority for the import or export of natural gas, including LNG, from and to a nation with which there is in effect a free trade agreement (FTA) requiring national treatment for trade in natural gas, and/or the import of LNG from other international sources, are deemed consistent with the public interest and granted without modification or delay. For Authorizations relating to those countries with which the United States does not have an FTA requiring national treatment trade in natural gas and with which trade is not prohibited by the United States law or policy, pursuant to Section 3(a) of the NGA, requires DOE to grant a permit to export domestically produced natural gas unless it finds that such action is not consistent with the public interest.[6]

DOE has identified a range of factors that it evaluates when reviewing an application for LNG export authorization. Specifically, DOE's review of export applications has focused on: "(i) the domestic need for the natural gas proposed to be exported, (ii) whether the proposed exports pose a threat to the security of domestic natural gas supplies, (iii) whether the arrangement is consistent with DOE's policy of promoting market competition, and (iv) any other factors bearing on the public interest as determined by DOE, such as international and environmental impacts."[7]

To inform its Public Interest determination, since 2012, the Office of Fossil Energy and Carbon Management and its predecessor, the Office of Fossil Energy, commissioned five studies on the effects of increased LNG exports on the U.S. economy and energy markets. The studies examined the impacts of increasing demand, including exports, on the domestic natural gas market.

This updated study, similar to the previous studies, was intended to serve as an input to be considered in the evaluation of applications to export LNG from the United States under Section 3 of the Natural Gas Act. DOE-FECM commissioned OnLocation, Inc., Pacific Northwest National Laboratory (PNNL), and the National Energy Technology Laboratory (NETL) to assess the economic level of U.S. LNG exports across seven scenarios representing a broad range of economic, environmental, and political scenarios, along with changes to global greenhouse gas emissions at differing levels of U.S. LNG exports. U.S. LNG exports were found using a global equilibrium model and were then inputted into the domestic model to examine the market effects of increased LNG exports, including natural gas price and consumption across sectors and changes in U.S. greenhouse gas emissions. Finally, the incumbent life cycle analysis of U.S. LNG exports was expanded to incorporate market effects from the results of this study.

B. Purpose of Study

Since the NERA 2018 report was published, several events altered the explicit and implicit assumptions underpinning the global and U.S. natural gas markets. These include: i) the issuance of additional DOE

[6] Natural Gas Act. 15 U.S.C. 717b.

[7] Order Amending Long-Term Authorization to Export Liquefied Natural Gas to Non-Free Trade Agreement Nations at 43, Magnolia LLC, Docket 13-132-LNG (April 2022).

LNG export authorizations, ii) the Russia-Ukraine war, iii) global and U.S. greenhouse gas policy developments, iv) technological change in production, transmission, storage, and end-use of natural gas, iv) and the passage of significant energy-related legislation in the U.S. (Bipartisan Infrastructure Law (BIL) and Inflation Reduction Act (IRA)). This report updated previous analytical work in line with current laws and regulations, as well as economic and technology conditions using newly derived scenarios. The defined seven scenarios included:

> ***S1*: Reference Exports** (Reference scenario in which U.S. LNG exports follow the Reference case from the U.S. Energy Information Administration's 2023 Annual Energy Outlook (AEO))
>
> ***S2*: Market Response** (U.S. LNG exports determined by global market equilibrium)
>
> ***S3*: High Global Demand** (U.S. LNG exports determined by global market equilibrium, higher population growth outside of the U.S.)
>
> ***S4*: Regional Import Limits** (U.S. LNG exports determined by global market equilibrium, global focus on maximizing consumption of local energy sources)
>
> ***S5*: Low-cost Renewables** (U.S. LNG exports determined by global market equilibrium, lower costs for variable renewable energy technologies)
>
> ***S6*: Energy Transition (Ref Exp)** (U.S. LNG exports are limited to the values from the AEO 2023 Reference case, countries achieve emissions pledges and pursue ambitious GHG mitigation policies consistent with limiting global warming to 1.5°C, U.S. emissions to net-zero by 2050)
>
> ***S7*: Energy Transition** (U.S. LNG exports determined by global market equilibrium, countries achieve emissions pledges and pursue ambitious GHG mitigation policies consistent with limiting global warming to 1.5°C, U.S. emissions to net-zero by 2050)

These scenarios are described in more detail in Section 1.A.

Several considerations were required in interpreting this study and its results. Foremost, this study was not intended to serve as forecasts of U.S. LNG exports, rather, it was an exercise in exploring alternative conditional "what-if" scenarios of future U.S. LNG exports and examining their implications for the global and U.S. energy and economic systems, and GHG emissions. Such scenario analysis is a well-established analytical approach for exploring complex relationships across a range of variables. In addition, the scenarios explored in this study were meant to span a range of plausible U.S. LNG export outcomes by 2050. However, they hinged on many assumptions about a wide range of domestic and international, and economic and non-economic factors such as future socioeconomic development, technology and resource availability, technological advance, institutional change, etc. A full uncertainty analysis encompassing all of the above factors was beyond the scope of this study. This study did not attach probabilities to any of the scenarios and no inference about the likelihood of these scenarios occurring should be made.

C. Organization of the Report

Following the Background of LNG Export Studies and Introduction sections of the Report, Section IV presents a more detailed review of the study methodology, scenario design, and key assumptions. The section introduces the scenarios, the versions of GCAM and NEMS models used for the analysis, and the life cycle analysis methodology. Section V of the report includes key results by scenario:

- U.S. LNG exports
- Global gas and primary energy consumption
- Implications for U.S. energy systems
- Life cycle analysis

IV. SCENARIOS, METHODOLOGY, AND KEY ASSUMPTIONS

Three primary analytical frameworks were used for this analysis: i) the Global Change Analysis Model (GCAM) developed and maintained at the Pacific Northwest National Laboratory's (PNNL's) Joint Global Change Research Institute, ii) the National Energy Modeling System (NEMS) developed by EIA and modified for this study by OnLocation, and iii) the natural gas system life cycle analysis (LCA) model developed and maintained by NETL. These frameworks and key assumptions are described below.

A. GCAM Model and Global Scenarios Design

GCAM is a model of the global energy, economy, agriculture, land use, water, and climate systems.[8] These systems are represented in 32 geopolitical regions, 384 land subregions, and 235 water basins across the globe. GCAM operates in five-year time-steps from 2015 (calibration year) to 2100 by solving for equilibrium prices and quantities of various energy, agricultural, water, land use, and greenhouse gas (GHG) markets in each time period and in each region. Outcomes of GCAM are driven by exogenous assumptions about population growth, labor participation rates and labor productivity in the 32 geo-political regions, along with representations of resources, technologies, and policy.

GCAM tracks emissions of twenty-four gases, including GHGs, short-lived species, and ozone precursors, endogenously based on the resulting energy, agriculture, and land use systems. GCAM's energy system contains representations of fossil resources (coal, oil, and gas), uranium, and renewable sources (wind, solar, geothermal, hydro, biomass, and traditional biomass) along with processes that transform these resources to final energy carriers (electricity generation, refining, hydrogen production, natural gas processing, and district heat), which are ultimately used to deliver goods and services demanded by end use sectors (residential buildings, commercial buildings, transportation, and industry). Natural gas competes for share with other fuels in the electricity generation sector, and with other fuels and electricity in the buildings, industrial, and transportation sectors. Each of the sectors in GCAM includes technological detail. In every sector within GCAM, individual technologies compete for market share based on the levelized cost of a technology (see appendix for more details). The version of GCAM used in this study also included a representation of three carbon dioxide (CO_2) removal strategies that were deployed in scenarios with emissions policies, namely, direct air capture (DAC), bioenergy in combination with carbon capture, utilization, and storage (BECCS), and afforestation.

The version of GCAM used in this study includes a representation of natural gas trade that creates price-based competition between domestic and imported natural gas. This representation introduces realistic inertia in the evolution of trade from current patterns. Natural gas can be imported as liquefied natural gas (LNG) or through pipelines. Traded LNG is represented as a single global market. All producers of natural gas can export to a global LNG pool from which importers can import. While the price of domestic gas is based on extraction costs that are derived from long-term regional resource supply curves, the price of imported LNG includes costs for shipping, liquefaction, and regasification in addition to extraction costs. Traded pipeline gas is represented in six regional markets (North America, Latin America, Europe, Russia+, Africa and Middle East, and Asia-Pacific). Exporters of pipeline gas export to one of the six regional pipeline blocs from which importers can import. Inter-pipeline bloc trade can also occur. For example, GCAM's China region exports only to the "Asia-Pacific" pipeline bloc but can import

[8] The full documentation of the model is available at the GCAM documentation page (http://jgcri.github.io/gcam-doc/), and the description here and in the appendix is a summary of the online documentation.

from the "Russia+" pipeline bloc and the "Asia-Pacific" pipeline bloc. These pipeline trade relationships are based on existing relationships. The price of imported pipeline gas includes the costs of building and operating pipeline infrastructure in addition to resource extraction costs. Gross exports and imports of LNG and pipeline gas are calibrated to historical data in GCAM's historical calibration year (2015). In a future model period, trade volumes evolve from historical patterns depending on future demands and prices. For the purposes of this project, historical natural gas producer prices in the U.S. are calibrated to the Henry Hub prices from the Energy Information Administration (EIA)[9] and in Canada, they are calibrated to Alberta marker prices from the BP Statistical Review.[10] For the rest of the world, natural gas producer prices in each GCAM region are based on the cost, insurance, and freight (CIF) prices from S&P.[11] In a future model period, as demand changes, the change in regional producer prices from the historical calibrated values are calculated endogenously using regional supply curves that represent increasing cost of extraction as cumulative extraction increases. GCAM also tracks turnover of trade infrastructure (e.g., liquefaction and regasification units, and pipelines). Trade infrastructure can either retire naturally or in response to economic changes (e.g., those driven by an emissions policy).

Using GCAM, we explored seven scenarios spanning a range of plausible U.S. LNG export outcomes by 2050 (Table 2). All of our scenarios include the 2022 Inflation Reduction Act in the U.S. and current emission policies in the rest of the world. The scenarios also include a constraint on Russian exports such that Russian pipeline exports to EU declined to a level below current levels by 2035 and then remain flat, LNG exports from Russia remain flat beyond 2025, and Russian pipeline exports to the east (e.g., to China) continue to increase. Our scenarios include planned and existing LNG capacity additions in major economies including the U.S., Middle East, Australia, Canada, Southeast Asia, and Africa. Socioeconomic (population and economic growth) assumptions for the U.S. were harmonized to the AEO2023 Reference.

The seven scenarios include:

> ***S1: Reference Exports*****.** This scenario assumes that the U.S. LNG exports follow the trajectory from the Reference case of the U.S. Energy Information Administration's (EIA's) 2023 Annual Energy Outlook (AEO2023) to grow to 27.34 Bcf/day in 2050. The AEO2023 Reference case incorporated U.S. LNG export projects that were either operating or under construction as of August 2022 and then added capacity based on the cost-competitiveness of exporting U.S. LNG to the international market including an annual capacity build-constraint. More specifically, in AEO2023, LNG export facilities had a combined operating capacity of 10.3 Bcf/d with an additional 4.5 Bcf/d of operating capacity under construction. AEO2023 projected an additional 12.6 Bcf/d of operating capacity that was assumed to be constructed in response to international demand for U.S. LNG.

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[9] U.S. EIA (2023). Henry Hub Natural Gas Spot Price. Available at: https://www.eia.gov/dnav/ng/hist/rngwhhda.htm

[10] BP (2022). bp Statistical Review of World Energy. 71st edition. Available at: https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/statistical-review/bp-stats-review-2022-full-report.pdf

[11] S&P Global (2023). S&P Global Commodity Insights. Historical and forecasted LNG prices data sheet.

S2: Market Response. This scenario has assumptions consistent with S1 and assumes economically driven, market-based outcomes for U.S. LNG exports.

S3: High Global Demand. This scenario includes the same assumptions as in *S2*, but assumes a higher population growth in regions outside of the U.S. consistent with the Shared Socioeconomic Pathways – 3.[12] This results in ~1 billion more people globally in *S3* by 2050 compared to *S1 and S2* and explores the effects of higher U.S. LNG exports driven by higher demand for all energy sources (including natural gas) compared to *S2*.

S4. Regional Import Limits. This scenario includes the same assumptions as in *S2*, but with constraints on natural gas imports globally to maximize the use of domestically produced natural gas across the world (Table A-1). This scenario explores the effects of lower U.S. and global LNG exports driven by global energy security concerns and trade limitations.

S5: Low-cost Renewables. *S5* includes the same assumptions as in *S2* but assumes lower capital costs for renewable energy technologies such as onshore and offshore wind, solar photovoltaic, concentrated solar power, and geothermal. This scenario explores the effects of faster technological improvements in competing technologies. While technology cost assumptions in other scenarios are consistent with NREL's Annual Technology Baseline (ATB) "Medium" assumptions, capital cost assumptions for onshore and offshore wind, solar photovoltaic, concentrated solar power, and geothermal technologies under *S5* are based on the "Low" assumptions.

S6: Energy Transition (Ref Cap) **and** ***S7: Energy Transition***. Both scenarios assume an emission pathway that is consistent with a global temperature change of 1.5°C by 2100 derived from published peer-reviewed literature.[13,14,15] Both of these scenarios assume that countries achieve their emission pledges as made during the 26th Conference of Parties of the United Nations Framework on Climate Change held in Glasgow. The pledges include nationally-determined contributions that outline emission reduction plans through 2030, long-term strategies, and net-zero pledges through mid-century. The U.S. is assumed to reduce economy-wide greenhouse gas emissions by 51% in 2030 and 100% by 2050. Countries without pledges are assumed to follow an emissions pathway defined by a minimum decarbonization rate of 8% that is indicative of strong mitigation policies and significant departure from historically observed decarbonization rates. The scenarios assume that countries achieve their pledges within their geographic boundaries without trading emissions. Scenario *S6* differs from *S7* in that it also limits U.S. LNG exports to the values from the AEO2023 Reference case. A key distinction between scenarios *S1* and *S6* is that while the former assumes the U.S. LNG exports to follow the AEO2023 Reference case exactly, the latter assumes the values from the AEO2023

[12] Samir, K. C., & Lutz, W. (2017). The human core of the shared socioeconomic pathways: Population scenarios by age, sex and level of education for all countries to 2100. Global Environmental Change, 42, 181-192.
[13] Fawcett, A. A., et al. (2015). Can Paris pledges avert severe climate change? Science, 350(6265), 1168-1169.
[14] Ou, Y., Iyer, G., et al. (2021). Can updated climate pledges limit warming well below 2°C? Science, 374(6568), 693-695.
[15] Iyer, G., Ou, Y., et al. (2022). Ratcheting of climate pledges needed to limit peak global warming. Nature Climate Change, 12(12), 1129-1135.

Reference case to be an upper bound. Nevertheless, scenario *S6* enables comparisons with *S1*, and scenario *S7* enables comparisons with *S2*.

Table 2. Scenario Descriptions

Scenario	Description	U.S. LNG Export Volumes (Bcf/d)
***S1*: Reference Exports**	Reference scenario in which U.S. LNG exports follow EIA's 2023 Annual Energy Outlook (AEO). Incorporates U.S. policy assumptions (including the 2022 Inflation Reduction Act). Assumes existing policies and measures, globally.	Grow to 27.34 Bcf/d by 2050
***S2*: Market Response**	Assumes policies consistent with *S1*, but U.S. LNG exports are determined by global market equilibrium.	GCAM Market Response
***S3*: High Global Demand**	Same assumptions as *S2*, U.S. LNG exports determined by global market equilibrium, but assumes higher population growth outside of the U.S.	
***S4*: Regional Import Limits**	Same assumptions as *S2*, U.S. LNG exports determined by global market equilibrium, but includes constraints on importing and exporting natural gas with a global focus to maximize use of domestic gas.	
***S5*: Low-cost Renewables**	Same assumptions as *S2*, U.S. LNG exports determined by global market equilibrium, but assumes lower capital costs for renewable energy technologies.	
***S6*: Energy Transition (Ref Exp)**	Assumes an emissions pathway consistent with a global temperature change of 1.5°C by end of century. Countries' emissions are constrained to announced GHG pledges, including the U.S. following a path to net-zero GHG emissions by 2050. NEMS follows CO_2 emissions constraint from GCAM. U.S. LNG exports are limited to the values from the AEO 2023 Reference scenario.	Grow to 27.34 Bcf/d by 2050
***S7*: Energy Transition**	Same emissions pathway assumptions as *S6*, but U.S. LNG exports are determined by global market equilibrium.	GCAM Market Response

B. NEMS Models and Analysis Methodology

NEMS is an energy-economic model of the U.S. It projects supply, demand conversion, imports, and exports of major energy commodities, drivers such as macroeconomic conditions, world energy markets, technology choices and costs, resource availability, and demographics. The NEMS model includes both cost minimization representative of competitive markets and behavioral representations of the energy market.

NEMS is a modular energy system model. There are four supply modules covering oil, natural gas, coal, and renewables. There are two conversion modules: converting primary fuels into electricity and petroleum and other liquids into liquid fuel products, respectively. There are four demand modules covering the residential, commercial, industrial, and transportation sectors. Other modules include the macroeconomic module, emissions policy modules, and an integrating module that synthesizes the output across all other modules. NEMS solves iteratively to reach a general market equilibrium across the energy economy. The EIA provides an archive of the NEMS model with source code and input sufficient to reproduce the reference and side cases comprising the Annual Energy Outlook.

1. AEO2023-NEMS

AEO2023-NEMS is OnLocation's version of the NEMS model, modified to allow exogenous input of U.S. LNG exports. The AEO2023 reference scenario has a macroeconomic growth assumption of 1.9% average growth per year. The model has the EIA's interpretation of the IRA which includes most major provisions of the policy. The model does not include carbon capture at industrial sites (ethanol, hydrogen, NGP, and cement) or direct air capture (DAC). Therefore, the IRA 45Q credit for DAC is not included. Similarly, IRA 45V hydrogen credits are also not represented in the AEO2023 version of NEMS as it does not have the hydrogen module.

2. FECM-NEMS

FECM-NEMS is a version of NEMS that includes updates that allow for the modeling of deep decarbonization technologies and strategies. FECM-NEMS models the Inflation Reduction Act based on FECM's interpretation of the policy. It includes major IRA energy-related provisions including but not limited to the extension of 45Q CO_2 sequestration credits, clean vehicle tax credits, energy efficient home tax credits and rebate programs, clean energy PTC and ITC, zero emission nuclear credits, and hydrogen tax credits. Additional modeling updates include provisions from the Bipartisan Infrastructure Law (BIL) such as funding for carbon capture demos, CO_2 transportation and storage infrastructure, and updated EPA/NHTSA CAFE standards.

Given the carbon capture opportunities and the net negative carbon technologies such as DAC and BECCS, the FECM-NEMS model allows the economy to achieve a net-zero carbon emission scenario.

FECM-NEMS is based on OnLocation's version of the Annual Energy Outlook 2022 (AEO2022) NEMS model. For consistency with updated economic assumptions, FECM-NEMS uses the low economic growth assumption from AEO2022, assuming a real GDP average growth of 1.8% per year to 2050. Under the Office of Carbon Management Policy & Analysis, DOE-FECM, the standard NEMS has been enhanced to represent several CO_2 mitigation technologies including carbon capture and sequestration (CCS), DAC, bioenergy with CCS (BECCS), and the Hydrogen Market Module (HMM). Industrial carbon capture is found in the liquid fuels module which allows for the construction of new hydrogen and ethanol facilities with CCS. It also allows for existing hydrogen, ethanol, and natural gas processing plants to retrofit CCS capability. The cement industry has also been enhanced to include CCS opportunities. Industries have the option to send captured CO_2 to an enhanced oil recovery market or store it in saline aquifers.

The HMM is integrated into NEMS to produce hydrogen via conventional and low carbon processes. The hydrogen production technologies available in the HMM include steam methane reformation (SMR), SMR with CCS, biomass gasification with CCS, and electrolysis.

3. Harmonizing GCAM and NEMS

While GCAM and NEMS are distinct models, coordination between them was necessary to maintain consistency and tie the NEMS results back to the global LNG market forecast. Harmonization efforts ensured that LNG exports (for all scenarios) and CO_2 emissions (in the net-zero scenarios) were consistent between the two models.

The EIA's AEO2023 reference case was selected to define *S1*. In AEO2023-NEMS, the AEO2023 reference case solution file was adopted for all variables. LNG exports from the AEO2023 reference case were then used as exogenous inputs into the GCAM model in place of endogenous estimates. For *S2* through *S7*, the process was reversed: the scenarios were first run in the GCAM model, from which endogenously calculated LNG export curves were taken and input exogenously into AEO2023-NEMS. The endogenous algorithm used by NEMS to calculate LNG exports was turned off for these scenarios. Since a key driver of LNG exports is the differential between domestic and world natural gas prices, domestic natural gas prices from NEMS were then compared with North American prices in GCAM. In all scenarios except *S5*, technology and resource were aligned between GCAM and the AEO2023 reference scenario. In *S5*, both models adjusted power generation technology assumptions consistent with the AEO2023 Low Renewable Cost scenario from the AEO.

For *S6* and *S7*, the net-zero scenarios were first run in the GCAM model, which uses global interactions and feedback to model U.S. LNG under a criteria of net-zero GHG by 2050. As part of the modeling process, GCAM generates a set of emissions curves that list quantities of GHG emissions of various sectors and gases (CO_2, CH_4, N_2O, F), as well as emissions and removals from land use, land-use change, and forestry (LULUCF). These curves were outputs of the model, although the sum of individual emissions was defined in the model inputs such that they reached or exceeded a net-zero target in 2050. The output emissions curves from GCAM were used to specify how the net-zero scenario was implemented in FECM-NEMS.

The values of CO_2 emissions from the energy sector were taken from the GCAM output and used explicitly as the carbon cap in FECM-NEMS to model the net-zero scenarios. The carbon cap curve (used to define both *S6* and *S7*) is plotted in Figure 1.

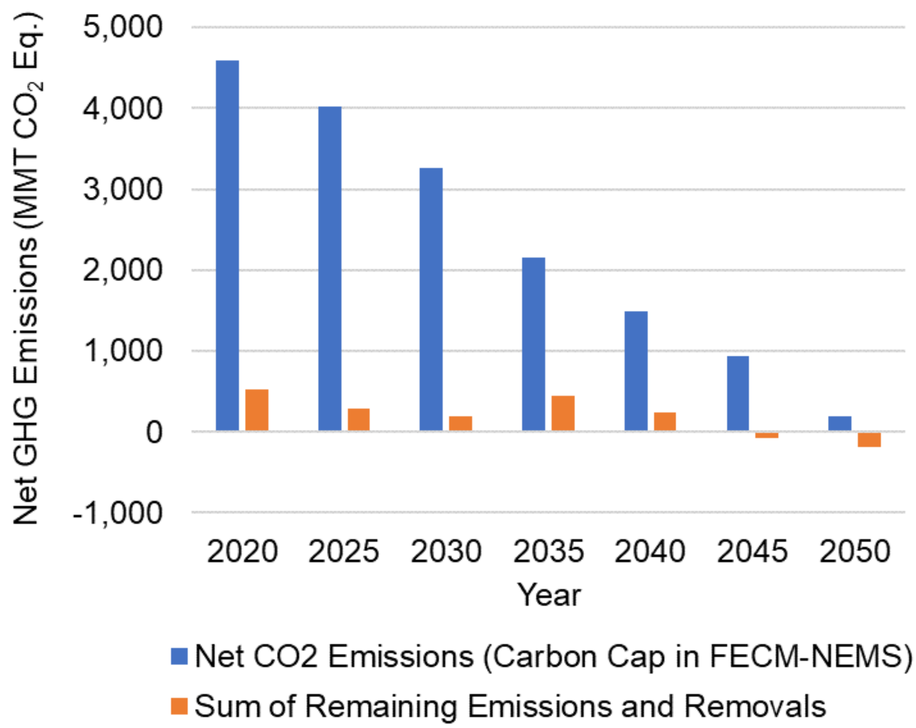


Figure 1. U.S. GHG emissions and removals in the net-zero scenarios

Referring to this carbon cap each model year, FECM-NEMS calculates emissions and removals throughout the model and adjusts a carbon price to equalize them with the carbon cap. With this method, FECM-NEMS ensures that the CO_2 emissions from the energy sector match the corresponding emissions from GCAM. Although FECM-NEMS calculates CH_4 emissions from natural gas systems, they were excluded from the carbon cap in favor of adopting the values calculated by GCAM.

The carbon cap used in FECM-NEMS for both net-zero scenarios ended with 187 MMT CO_2 in 2050. Although this value does not equal zero, it was balanced by the sum of non-energy CO_2, non-CO_2 GHGs, and LULUCF-sector emissions and removals calculated by the GCAM model which added together total -185 MMT CO_2 equivalent (the total was negative because of large quantities of LULUCF-sector removals). The remaining emissions and removals (non-energy CO_2, non-CO_2 GHGs, and LULUCF) were treated as exogenous to FECM-NEMS and could be added with the endogenous CO_2 emissions to calculate net total GHG emissions (which would equal near-zero in 2050). The sum of non-energy CO_2, non-CO_2 GHGs, and LULUCF-sector emissions and removals is also plotted in Figure 1.

C. NETL Life Cycle Analysis Model Methodology

Past life cycle studies conducted by NETL on natural gas and LNG have been attributional studies that estimate the emissions and other impacts associated with current units of natural gas/LNG delivered. These LCA studies 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 different sources of natural gas compete in the market, or 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 GHG emissions. As part of this study, these consequential effects were estimated by tracking differences in global GHG emissions and quantities of LNG exported from the GCAM model results.

This section details 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 apply the insights from the GCAM model to the NETL LCA framework.

1. Past NETL Natural Gas Life Cycle Reports

As shown in the top half of Table 3, the NETL Natural Gas model[16] 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)[17] and Greenhouse Gas Inventory (GHGI)[18]. 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 natural gas is delivered through smaller distribution pipelines). Results are provided for various techno-basins of production, regions, and U.S. average production, using a variety of IPCC Assessment Report Global Warming Potential (GWP) values on 100-year or 20-year basis.

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 3.

Table 3. 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

[16] Khutal, H., et al. Life Cycle Analysis of Natural Gas Extraction and Power Generation: U.S. 2020 Emissions Profile. National Energy Technology Laboratory, Pittsburgh, July 7, 2023
[17] US EPA Greenhouse Gas Reporting Program, https://www.epa.gov/ghgreporting, last accessed Sept 1, 2023.
[18] US EPA , Inventory of U.S. Greenhouse Gas Emissions and Sinks, https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks, last accessed Sept 1, 2023.

	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 delivery 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.
Destination Transmission / Distribution	Similar processes as described above, and not functionally different than as described for the natural gas only part.

Quantitatively, the NETL natural gas model has estimated ranges of GHG emissions by species and by stage for the domestic natural gas supply chain as shown in Figure 2. Given the scope of domestic natural gas production through the transmission stage, the mean U.S. average total CO_2-equivalent emissions are about 7.44 g CO_2e/MJ (IPCC AR6, 100-year basis), with a confidence interval of the mean of 4.6-11.1 g CO_2e/MJ. 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 U.S. average. Note that these results are in terms of Higher Heating Value (HHV) of natural gas, while the GCAM model uses Lower Heating Value (LHV), so needed to be subsequently adjusted.

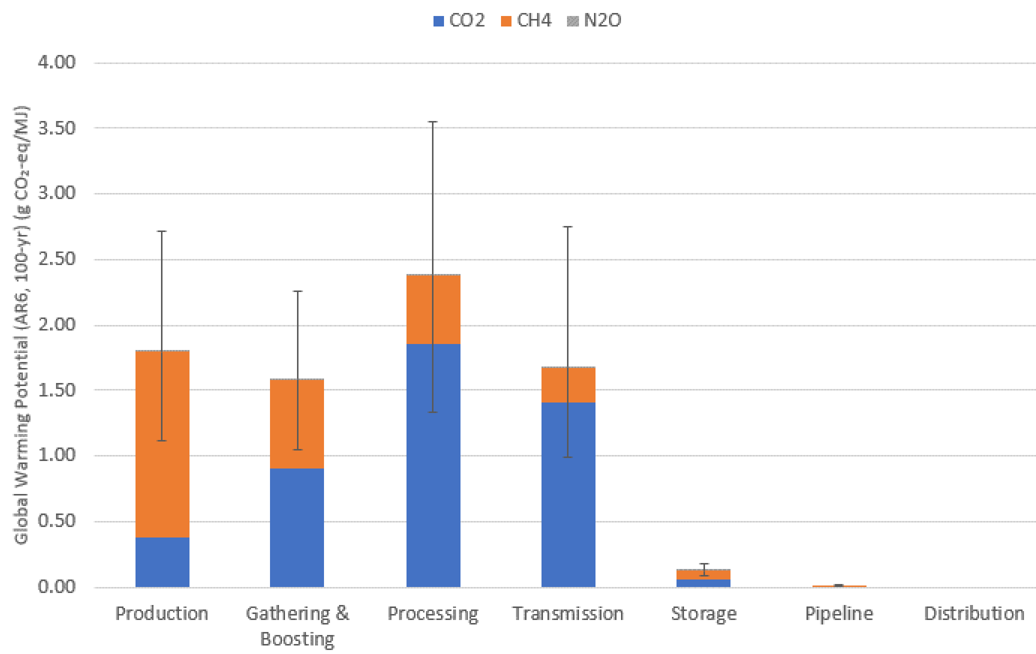


Figure 2. Life cycle GHG emissions from the 2020 U.S. average Natural Gas supply chain, HHV basis (Source: NETL 2023)

Past work by NETL also estimated the greenhouse gas emissions implications of the additional stages to produce and deliver U.S. average LNG around the world[19]. 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 CO_2e/MJ delivered (IPCC AR6, 100-year basis, HHV). In short, the additional processes and natural gas needed to liquefy, ship, and regasify natural gas to Rotterdam adds about 10 g CO_2e/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 CO_2e/MJ, HHV basis, given above). The GHG emissions intensity result on a per MJ NG delivered to liquefaction plant basis is 7.44 g CO_2e/MJ (AR6, 100-yr, HHV) 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 CO_2e/MJ NG delivered to power plant (AR6, 100-yr, HHV). 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.[20]

The previous NETL work on natural gas cited above are attributional studies of the domestic natural gas system. The results sought to identify and attribute the emissions associated with the various unit

[19] Roman-White, S., Rai, S., Littlefield, J., Cooney, G., & Skone, T. J. (2019). Life cycle greenhouse gas perspective on exporting liquefied natural gas from the Unites States: 2019 update. National Energy Technology Laboratory (NETL), Pittsburgh, September 12, 2019.

[20] Results from Roman-White 2019, Exhibit A-2, adjusted from g CO_2e/MWh to g CO_2e/MJ using heat rate of 145 kg natural gas/MWh, and higher heating value of 54.3 MJ/kg.

processes that created them. These methods differ in scope than consequential analysis which more broadly considers the global changes in GHG emissions when additional volumes of U.S. natural gas are produced and delivered across the world, or, in other words, the market-based effects of producing domestic natural gas and exporting it. Further discussion on how the LCA section of this project can support consequential analysis is discussed in Section V.G.

2. Market Adjustment Factors

In order to quantify the broad and global market effects associated with increasing exports of U.S. LNG, the GCAM results were used 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 U.S. LNG exports between the same two scenarios. For example, a comparison of Scenario *S*2 vs. Scenario *S1* would compare the differences in GCAM values for these two scenarios. This MAF can be calculated for every model year (2015-2050) and can also use linearly interpolated values for the non-modeled years.

V. Results

The following sections describe the results of the global analysis using GCAM, the U.S. analysis using NEMS, and the life-cycle analysis in that order. To highlight the implications of the availability of additional U.S. LNG in the global market, we first compare *S1* and *S2*. We then discuss *S6* and *S7* to illustrate the implications of additional U.S. LNG in the global market under a global transition toward 1.5°C. Subsequently, we discuss results from the remaining scenarios (*S2*-*S5*).

A. U.S. LNG exports

Across all the scenarios, the U.S. is a net exporter of natural gas. As shown in Figure 3, U.S. LNG exports increased beyond existing and planned capacity in all scenarios by 2050, except *S1* in which U.S. LNG export volumes followed AEO2023 and *S6* in which export volumes were limited to AEO2023 by design. Under *S2,* in which all outcomes – including U.S. LNG exports – are economically driven and market-based, U.S. LNG exports increased to ~47 Bcf/day in 2050.

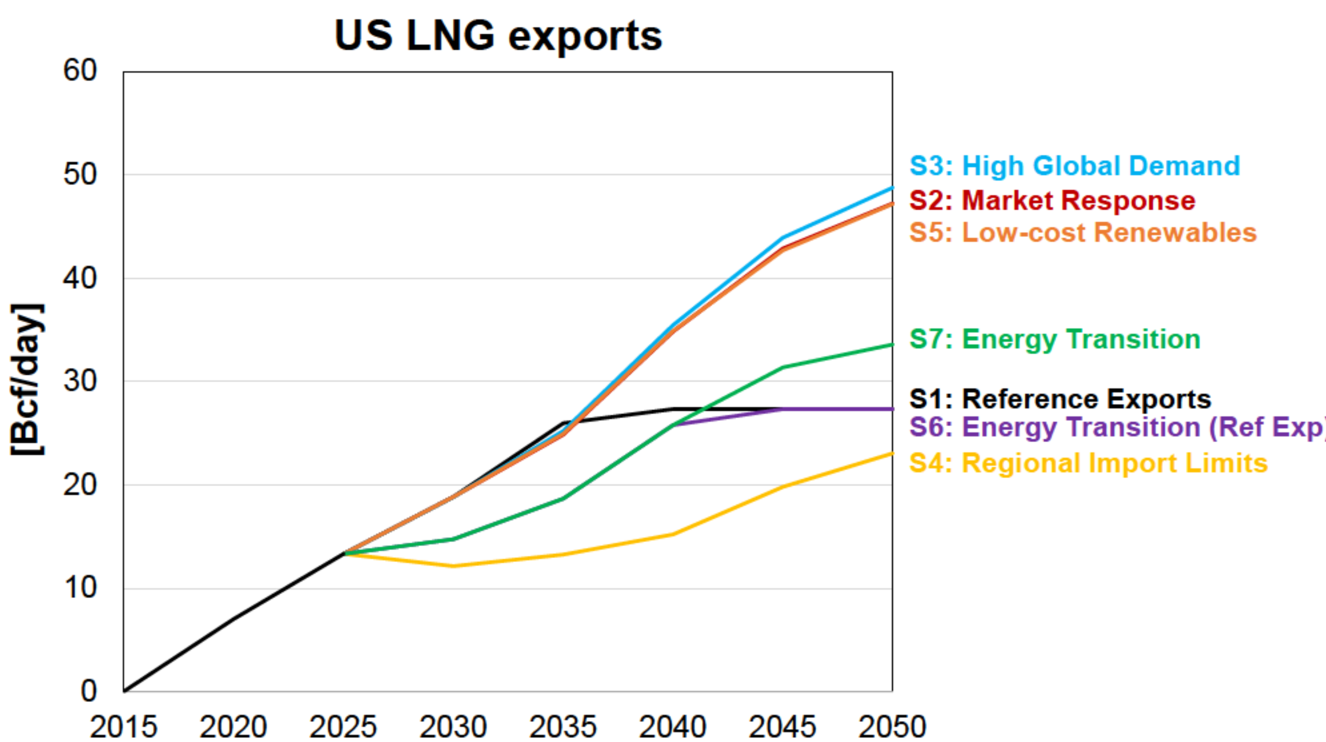


Figure 3. U.S. LNG exports across the scenarios. Note that the U.S. LNG export outcomes for S2 and S5 are very close to each other.

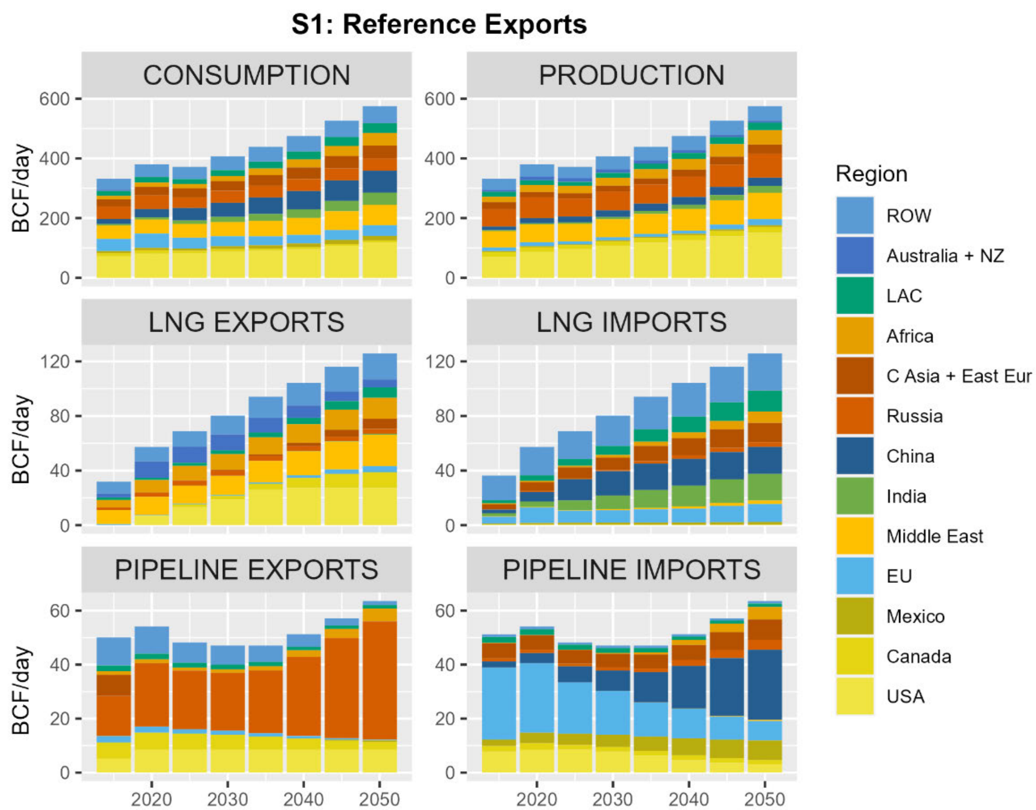
U.S. LNG exports under *S3*, the scenario with increased global population, increased to 49 Bcf/day in 2050, emerging as the upper bound. With higher population assumptions in *S3*, total energy demand – and consequently natural gas demand – outside the U.S. increased compared to *S2*, resulting in an increase in U.S. LNG exports to satisfy the increased international demand. However, the increase was not proportional to the increase in population because part of the higher demand in *S3* was supplied by an increase in international production.

U.S. LNG exports under *S4* increased only to ~23 Bcf/day in 2050, emerging as the lower bound. The lower increase in U.S. LNG exports in *S4* compared to other scenarios was driven by international limits on natural gas imports to maximize the use of locally produced gas.

U.S. LNG exports under *S5* increased to approximately the same level as *S2* in 2050. This was mainly because cheaper solar and wind technologies in this scenario mostly displaced fuels other than natural gas (e.g., biomass). Hence, the demand for natural gas and consequently, U.S. LNG exports, remained materially unaffected compared to *S2*. Under *S7,* which assumes a global transition toward 1.5°C, U.S. LNG exports continued to increase, albeit at a lower level than *S2,* to ~34 Bcf/day in 2050. As discussed below, the lower increase in U.S. LNG exports in this scenario compared to *S2* was driven by the economy-wide transition to low-carbon fuels to meet emission reduction commitments and pledges.

B. Global Natural Gas Consumption, Production, and Trade Under Scenarios *S1* And *S2*

As shown in Figure 4, under *S1*, production, consumption, and trade of natural gas increased in all regions, globally driven by growing demands in the electricity generation, industrial, and buildings sectors (see Figure A-1 in appendix A). Under *S1*, U.S. LNG exports followed the AEO2023 Reference case to grow to 27.34 BCF/day by 2050 (by design).



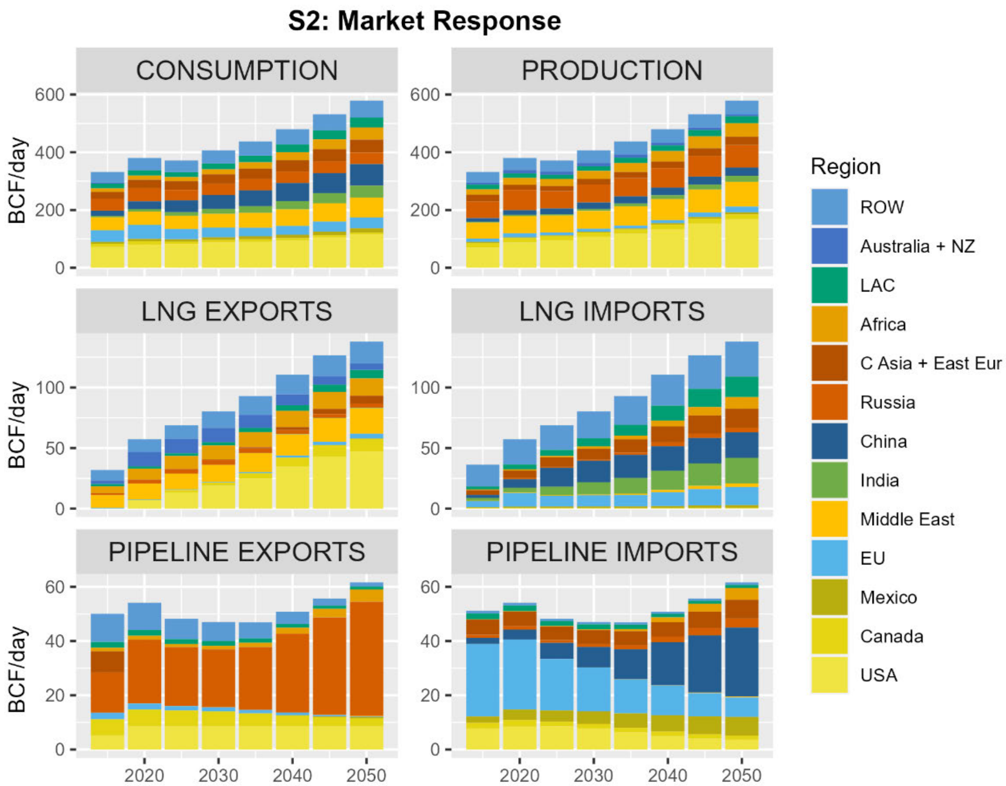


Figure 4 Natural gas consumption, production, and trade by region under S1 (upper) and S2 (lower)

As shown in Figure 5, under *S2*, in which U.S. LNG exports were determined by market equilibrium, U.S. natural gas production and LNG exports increased compared to *S1* to satisfy the growing demands of natural gas globally. Under *S2*, U.S. LNG exports grew to ~47 Bcf/day by 2050. In this scenario, the availability of additional U.S. natural gas in the global natural gas market at competitive prices resulted in a reduction in production and LNG exports from other parts of the world. The increased availability of U.S. LNG in the global market also resulted in higher LNG imports and reduced pipeline trade outside of the U.S. However, global natural gas consumption in *S2* increased only by a very small amount (<5% by 2050 globally compared to *S1*). This is mainly because the availability of additional U.S. LNG in the global market did not materially affect the relative competitiveness of natural gas compared to other fuels (e.g., coal, oil, renewables, and nuclear) globally. In addition, current emission reduction policies in the U.S. and internationally, which were included in the assumptions for all scenarios, limited the potential for global natural gas consumption to grow in response to the increased availability of U.S. natural gas. Consequently, global primary energy consumption and GHG emissions under *S2* did not change much compared to *S1*, as shown in Figure 6.

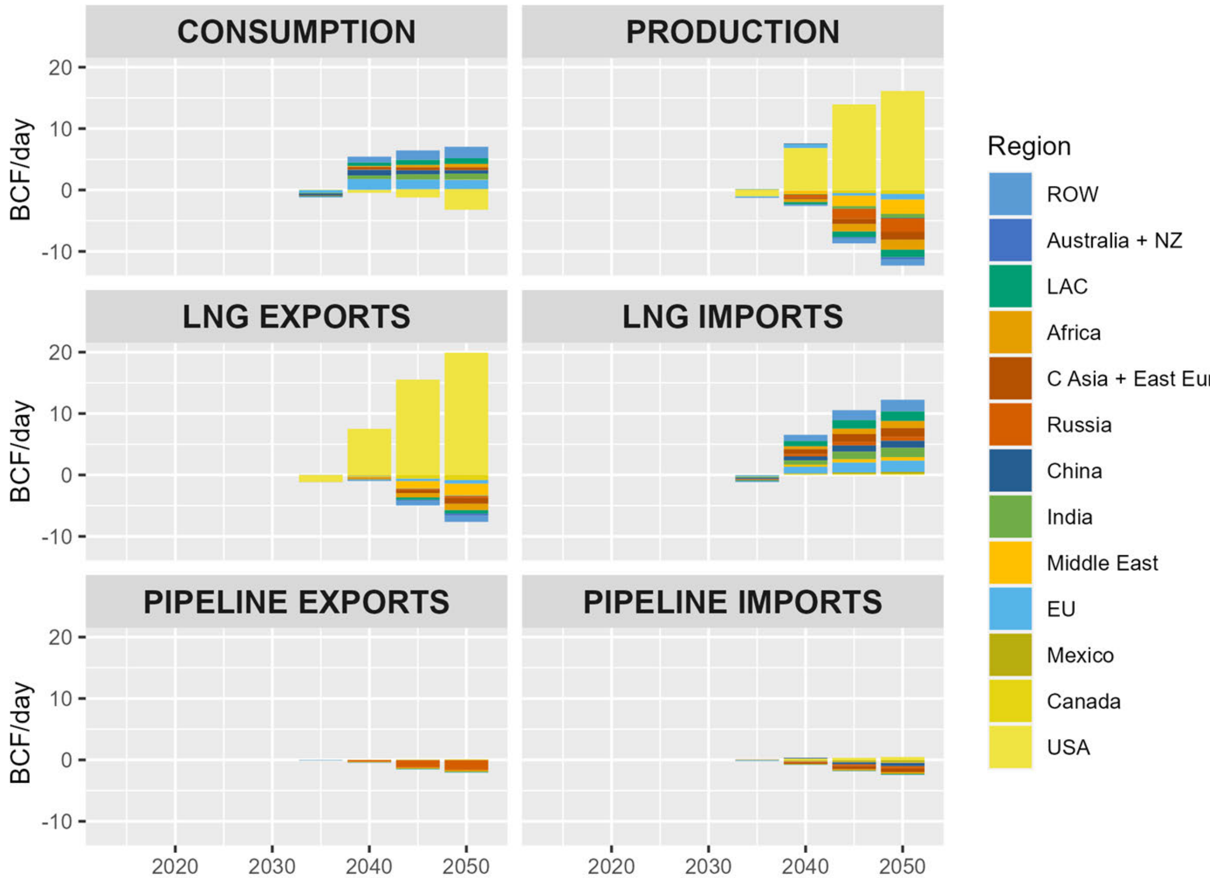


Figure 5. Changes in natural gas consumption, production, and trade by region in S2 vs. S1

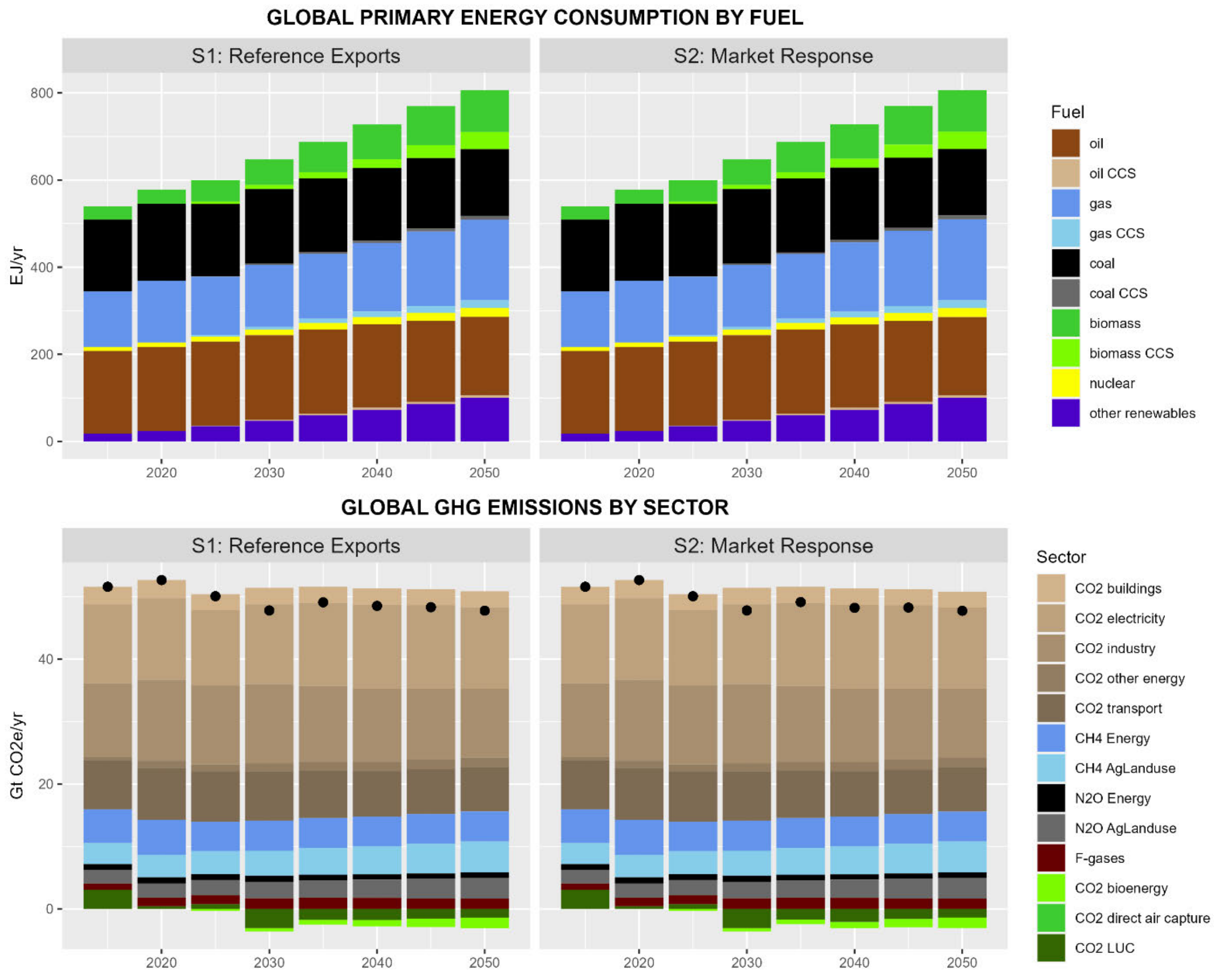


Figure 6. Global primary energy consumption by fuel and GHG emissions by sector under S2 and S1. Net GHG emissions are shown as a dot in each bar.

C. Global Primary Energy Consumption by Fuel and GHG Emissions by Sector Under *S6* And *S7*

Under *S6* and *S7*, global GHG emissions from all sectors of the economy reduced significantly compared to *S1* and *S2* as shown in Figure 7 and Figure 8. This was by design as these scenarios were assumed to include emissions pledges and constraints on emissions consistent with limiting global temperature change this century to 1.5°C. These scenarios were characterized by a combination of the following decarbonization strategies: i) a reduction in fossil fuel consumption without carbon capture utilization and storage (CCUS), ii) increased deployment of CCUS with fossil fuels, iii) increased deployment of renewables, iv) a net reduction in energy consumption, and v) increased deployment of carbon dioxide removal (CDR) applications such as bioenergy in combination with CCUS (BECCS), afforestation, and direct air capture (DAC) compared with *S1* and *S2*.

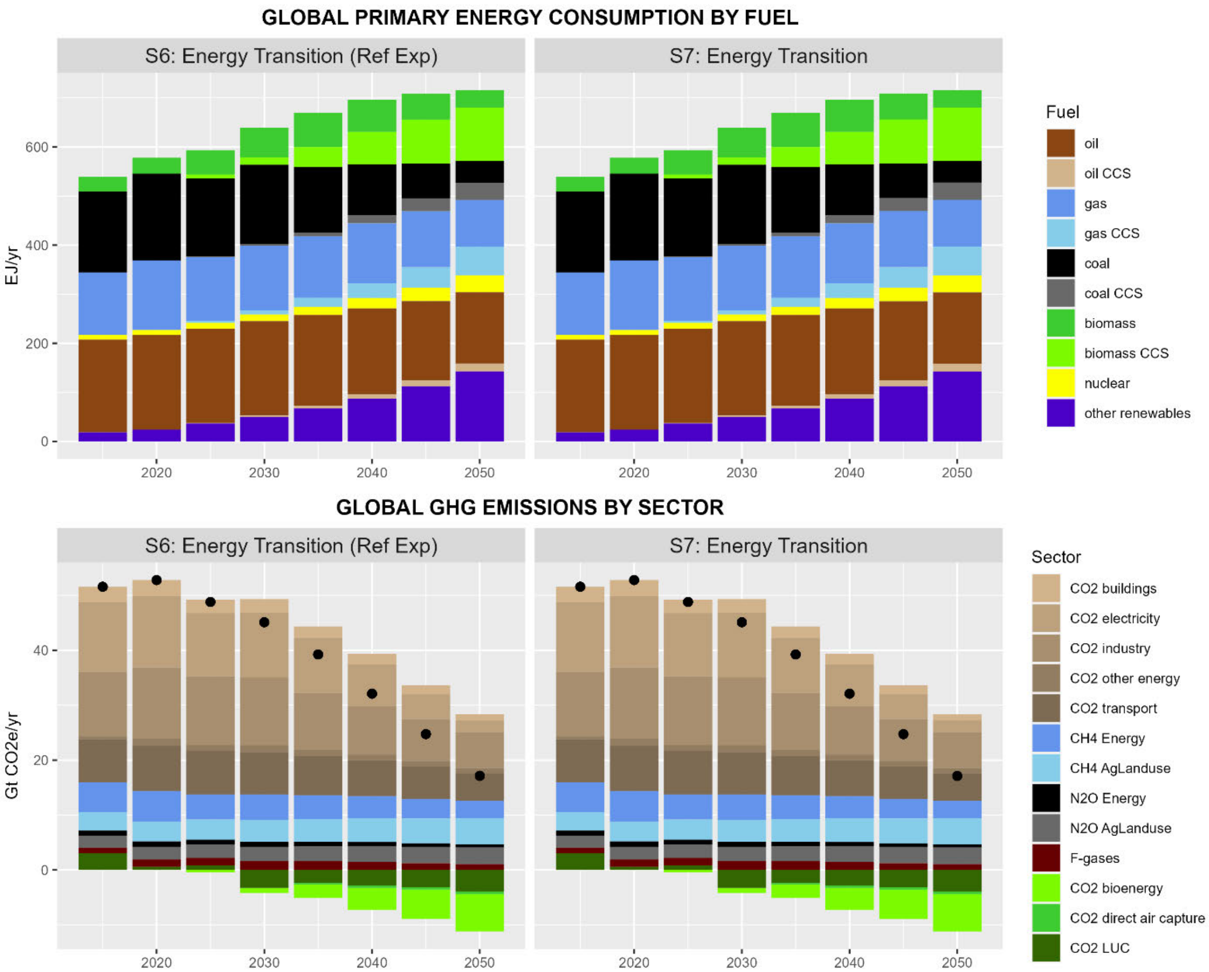


Figure 7. Global primary energy consumption by fuel and GHG emissions by sector under S6 and S7. Net GHG emissions are shown as a dot in each bar.

Notably, the scale and distribution of CDR deployment varied by type and region. By 2050, about 6.8, 4, and 0.4 $GtCO_2e$ respectively of BECCS, afforestation, and DAC were deployed globally in *S6* and *S7*, as shown in Figure 9. While BECCS and afforestation were distributed more evenly across regions, most of the DAC was deployed in the U.S. primarily due to the availability of carbon storage.

Note that *S6* and *S7* did not assume the availability of any emissions trading or offset mechanisms. Hence, countries with net-zero pledges – such as the U.S. – were assumed to meet those pledges in the stated target years through a combination of the above decarbonization strategies including CDR deployment within their own geographic boundaries. Under these scenarios, although global GHG emissions are net-positive (~20 $GtCO_2e$), global CO_2 emissions were ~0 in 2050. These global emissions outcomes were broadly consistent with 1.5°C scenarios in the literature.[21]

[21] Riahi et al. 2022, Chapter 3 in the Sixth Assessment Report of the IPCC

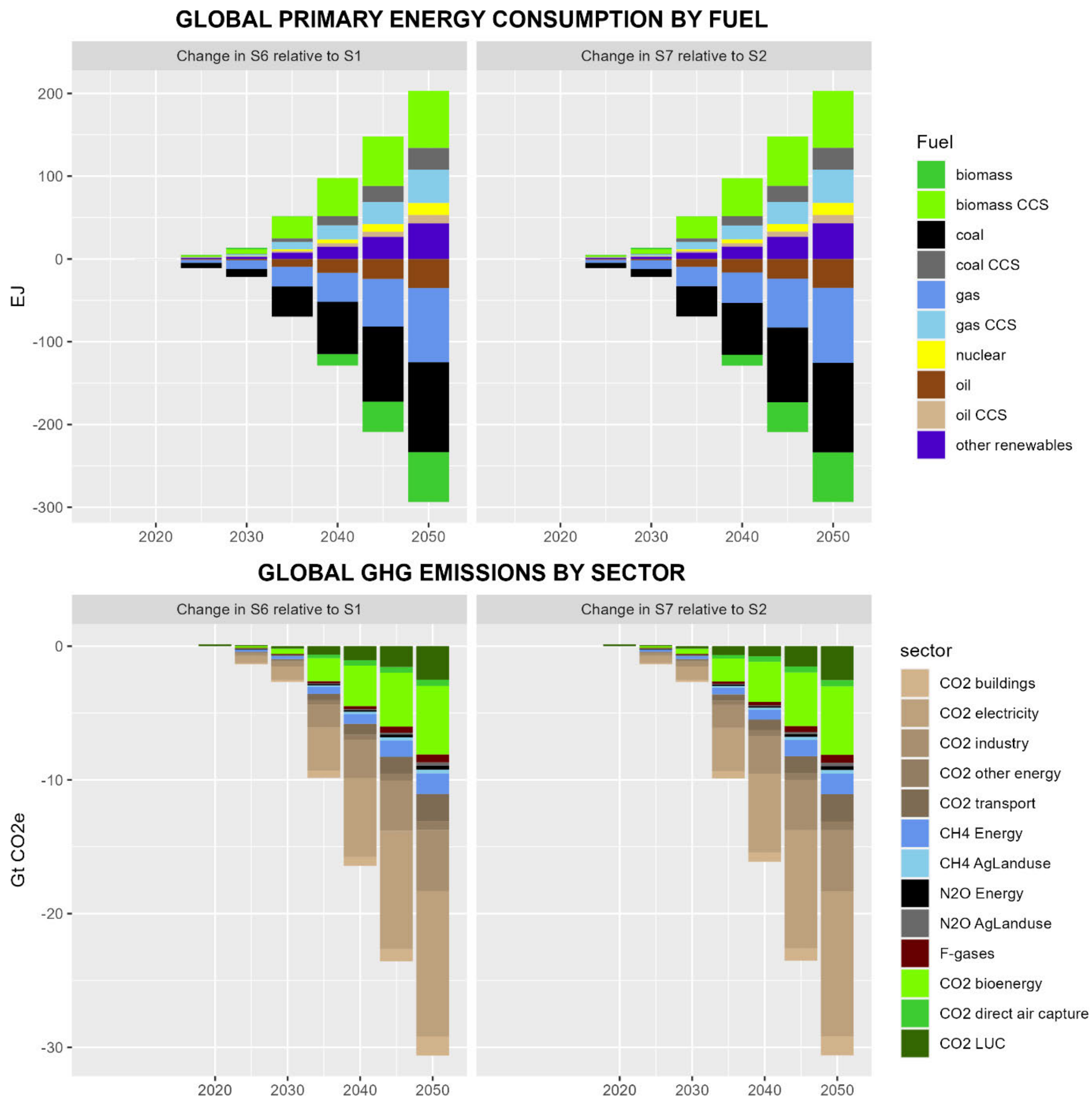


Figure 8. Changes in global primary energy consumption and GHG emissions under S6 and S7 relative to S1 and S2 respectively

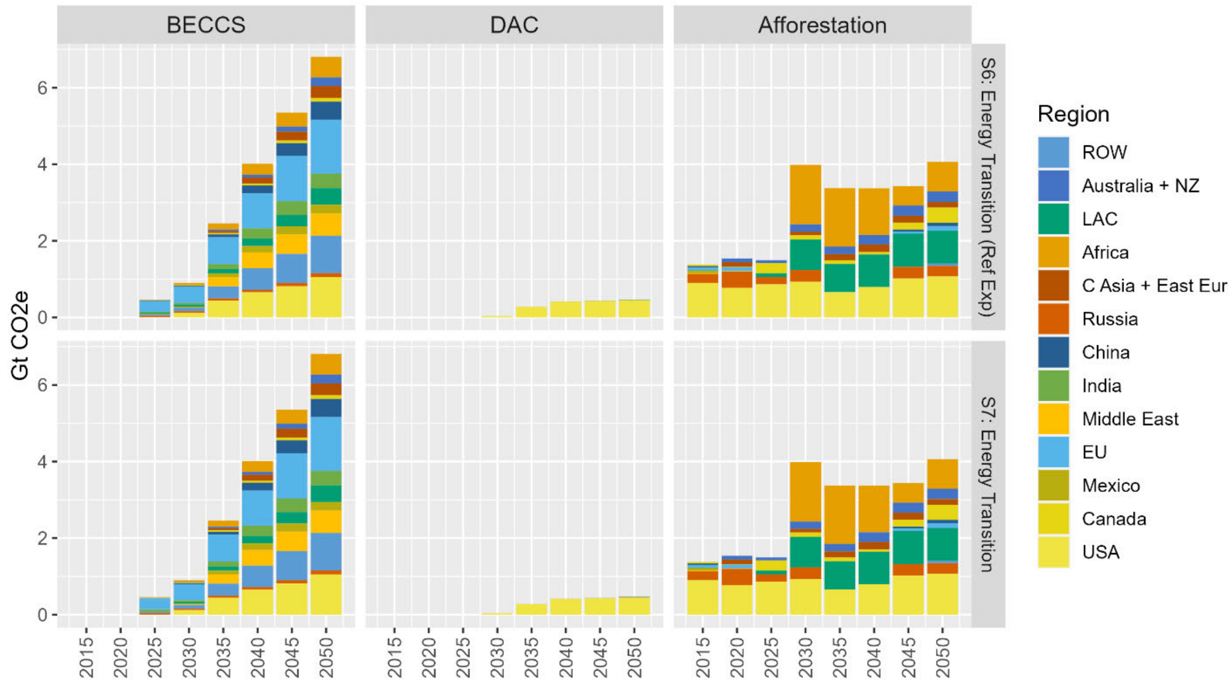


Figure 9. CDR deployment by type and region in S6 and S7

D. Global Natural Gas Consumption, Production, and Trade Under Scenarios *S6* and *S7*

As shown in Figures 10 and 11, under *S6* and *S7*, natural gas consumption decreased compared to *S1* and *S2* in most regions largely driven by official net-zero pledges that require complete decarbonization of energy systems by 2050. However, in some regions with net-zero pledges that extend beyond 2050 (e.g., India), natural gas demand continued to grow through 2050 and consumption did not change much compared to *S1* and *S2*. Globally, although natural gas consumption in *S6* and *S7* was lower compared to *S1* and *S2*, it continued to grow due to the deployment of natural gas with CCUS in power and industrial sectors and direct air capture (DAC) applications (see Figure A-2 in appendix). The lower natural gas consumption in *S6* and *S7* compared to *S1* and *S2* resulted in lower global production, LNG exports, and LNG imports.

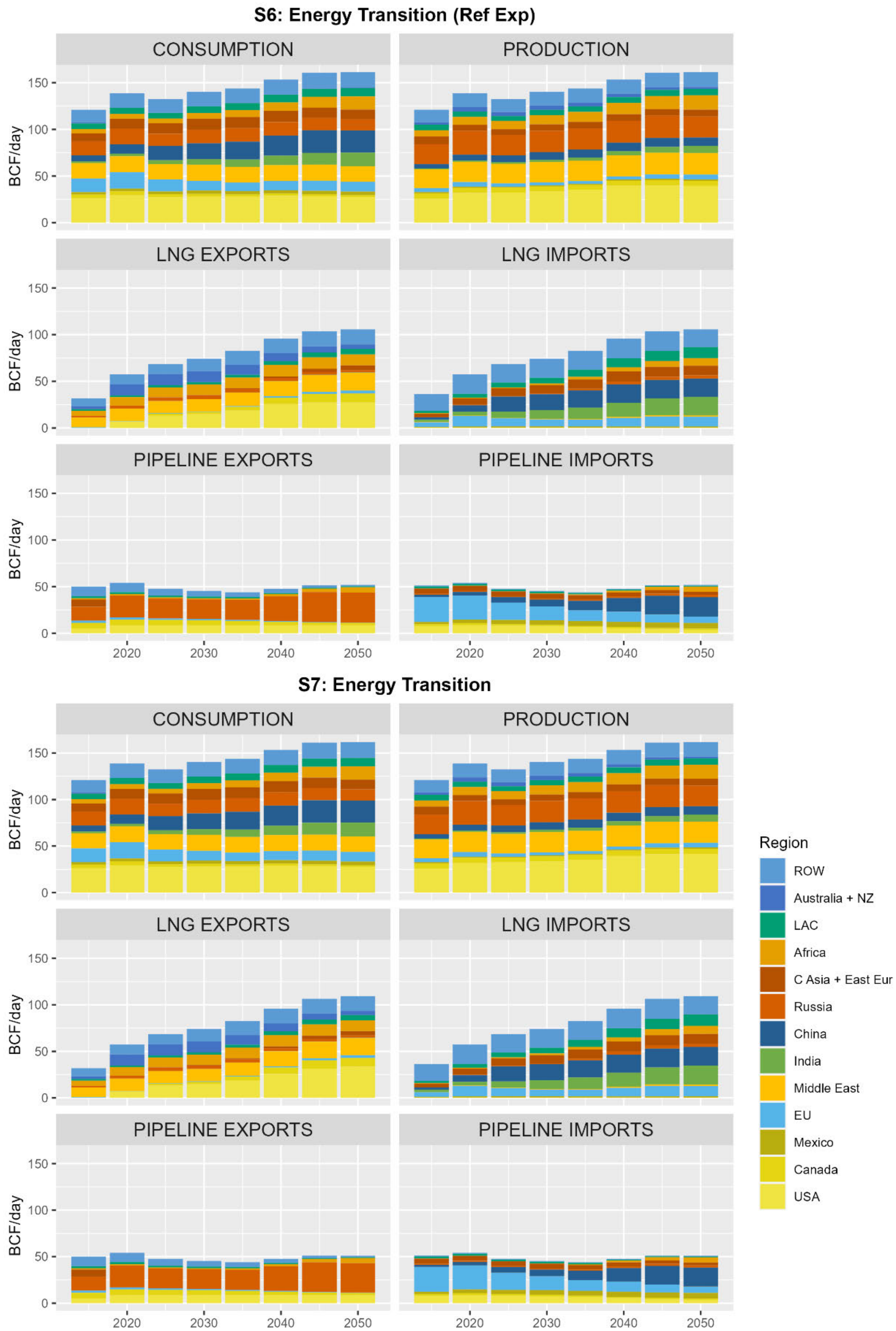


Figure 10. Natural gas consumption, production, consumption, and trade by region under S6 and S7

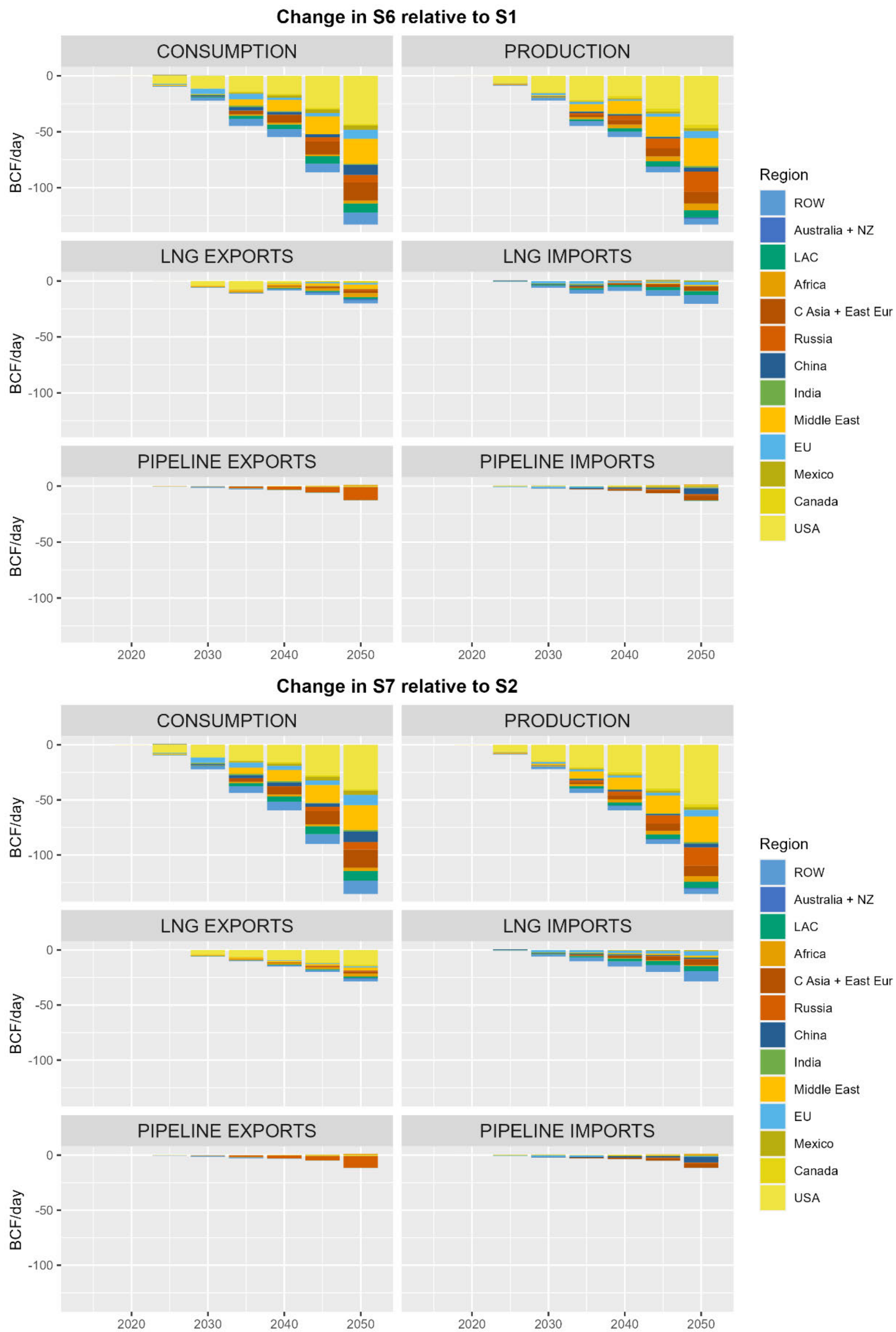


Figure 11. Changes in natural gas consumption, production, and trade by region: S6 vs S1 and S7 vs S2

As shown in Figure 12, *S6* and *S7* differed in the role of U.S. LNG exports in the global natural gas market. By 2050, U.S. LNG exports in *S6* were not different from *S1* because this scenario assumed the *S1* values (which are based on AEO2023) as an upper bound. Under *S7*, which assumes economically driven outcomes, U.S. LNG exports continued to grow and increase beyond *S6* – particularly after 2040 – to meet the global demand for natural gas, a growing share of which was deployed in combination with CCUS in the power and industrial sectors (see Figure A-1 in the appendix). Similar to the comparison between *S1* and *S2*, the availability of additional U.S. LNG in *S7* resulted in a very small increase in natural gas consumption, reduction in production, reduction in LNG exports, increase in LNG imports, and reduction in pipeline trade in the rest of the world compared to *S6*.

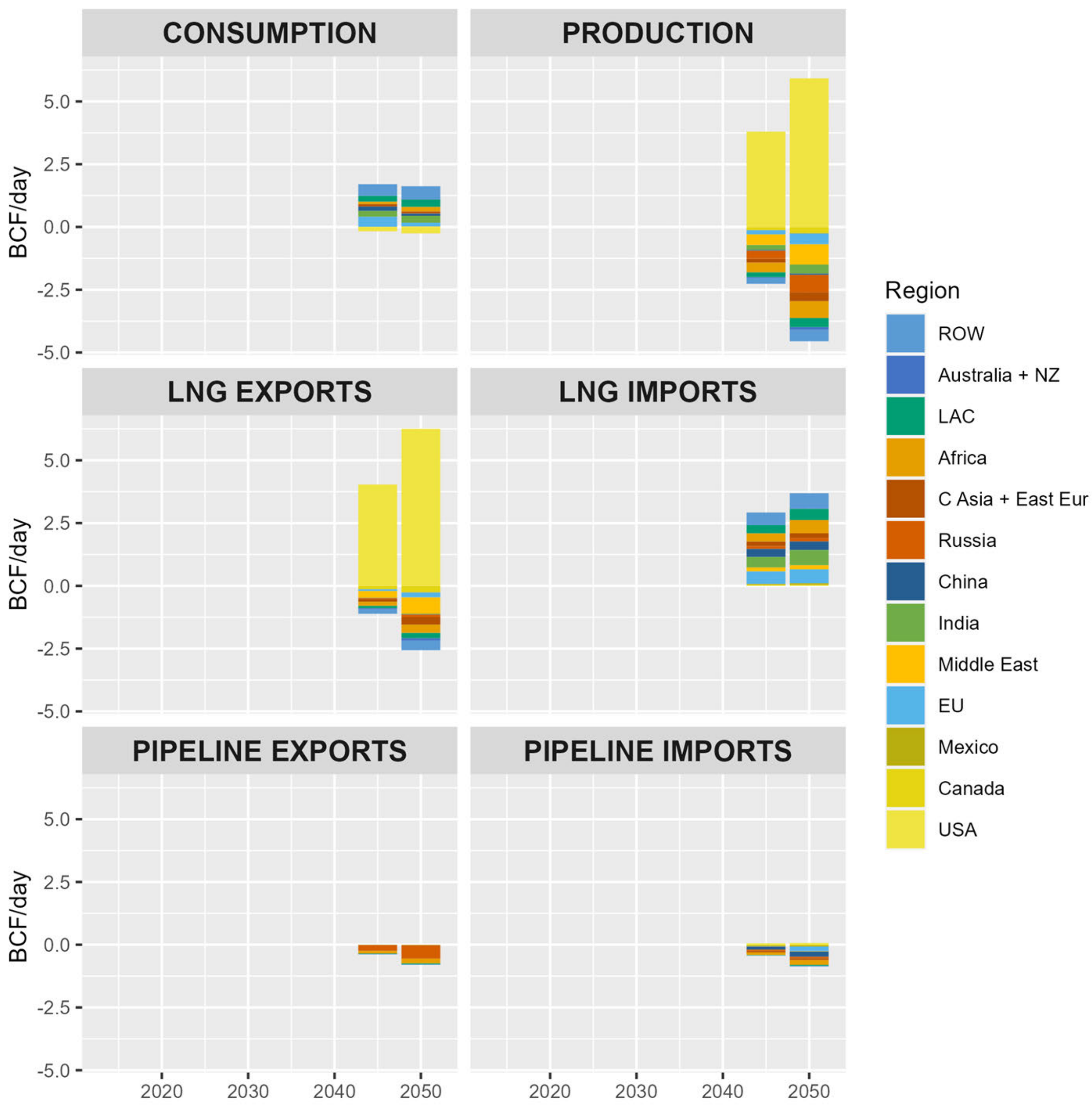


Figure 12. Changes in natural gas markets in S7 vs. S6

E. Global Primary Energy Consumption and GHG Emissions Across All Scenarios

Overall, the seven scenarios explored in this study resulted in a range of outcomes for global primary energy consumption and emissions by 2050. As shown in Figure 13, the fuel composition of primary energy consumption and the sectoral allocation of GHG emissions were not very different across scenarios *S1* through *S5*. Total primary energy consumption and GHG emissions were highest under the S3 scenario driven by higher population growth and associated increases in energy demand.

Total emissions in 2050 under scenarios *S1* through *S5* were relatively similar to 2015 levels because these scenarios included current policies and measures to deploy lower emission technologies. However, total primary energy consumption in 2050 under these scenarios was significantly higher compared to 2015 primarily driven by population and economic growth.

By contrast, total energy and emissions were lowest in scenarios *S6* and *S7* due to assumptions about countries meeting emission pledges and further emission declines to reach a global temperature change of 1.5°C by the end of century. As described earlier, these scenarios were also characterized by significant changes in the fuel composition of global energy consumption and the deployment of carbon dioxide removal technologies.

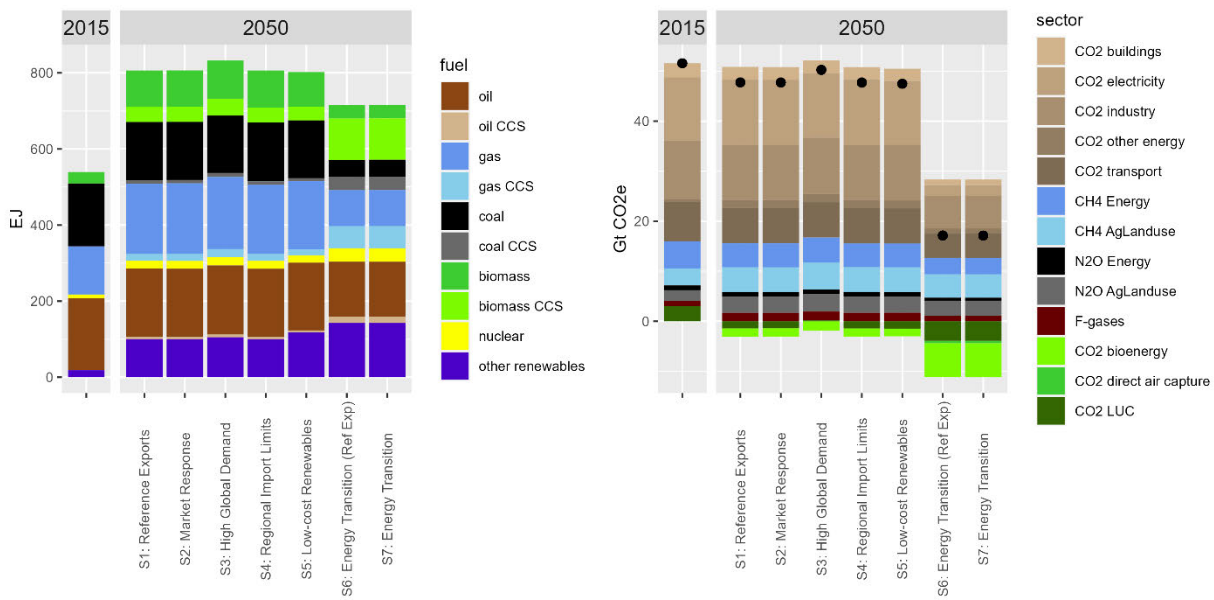


Figure 13. Primary energy consumption by fuel and GHG emissions by sector under all scenarios

F. NEMS Analysis: Implications for U.S. Energy Systems

1. Energy Impacts

AEO2023-NEMS and FECM-NEMS were used to model U.S.-specific results for *S1* through *S5* and *S6* through *S7*, respectively. Similar to global energy consumption, primary energy consumption in the U.S. grew over time in each scenario.

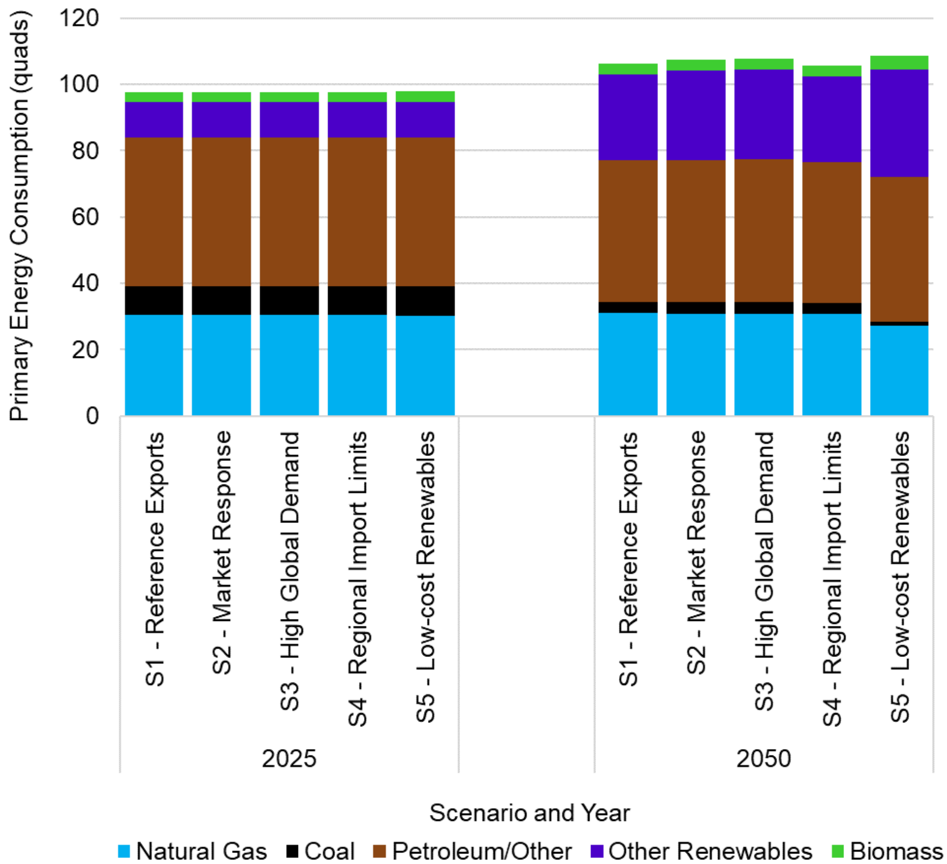


Figure 14. U.S. primary energy consumption, S1 through S5

In 2025, the primary energy consumption was at approximately 98 quadrillion BTUs in scenarios *S1* through *S5,* as shown in in Figure 14. By 2050, all scenarios saw an increase in total energy consumption, exceeding 105 quadrillion BTUs. The highest energy consumption was recorded in scenario *S5* at 109 quadrillion BTUs, and the lowest consumption was in scenario *S4* at 105 quadrillion BTUs.

The availability of low-cost renewables in scenario *S5* fosters the deployment of biomass and other renewable energy sources. A substantial decrease was noted in coal usage, with the most significant reduction occurring in scenario *S5*. Natural gas consumption remained steady across scenarios *S1* through *S4*, hovering around 31 quadrillion BTUs, but experienced a decline to 27 quadrillion BTUs in scenario *S5*.

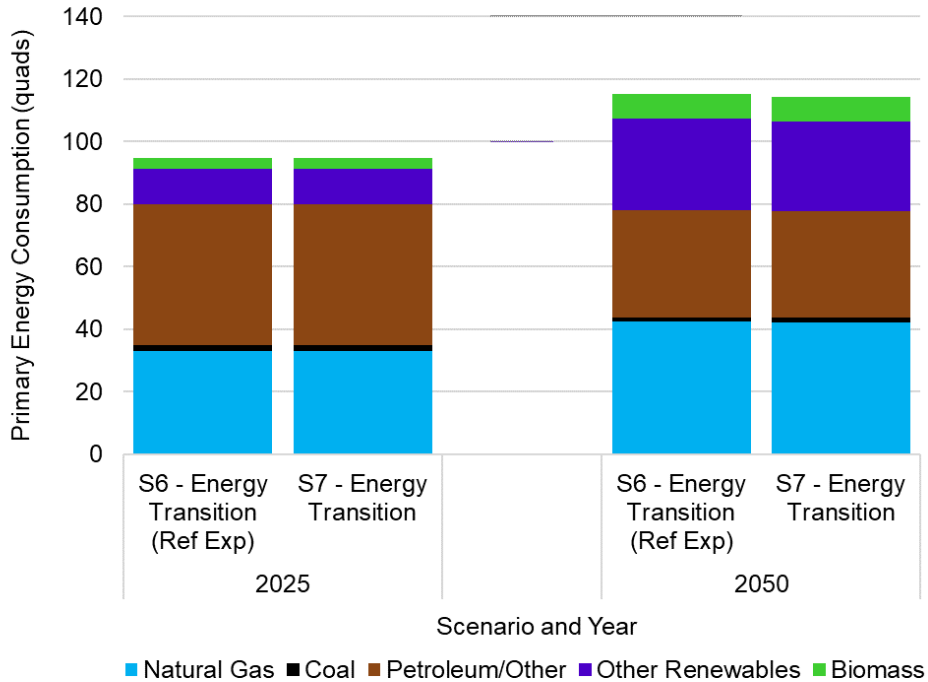


Figure 15. U.S. primary energy consumption S6 and S7

Figure 15 shows U.S. primary energy consumption across *S6* and *S7* in 2025 and 2050. In 2025, U.S. primary energy consumption was predominantly driven by fossil fuels, which accounted for 85% of the total energy use. By 2050, energy consumption rose across both scenarios relative to 2025, distinguished by a notable increase in biomass and other renewables. Relative to *S6*, increased LNG exports in *S7* put pressure on the natural gas market, leading to slightly higher end-use prices and more expensive GHG mitigation strategies. Biomass and other renewable sources grew by 22.3 and 22.1 quadrillion BTUs from 2025 in the *S6* and *S7* cases respectively, thereby contributing 32.1% of the total energy consumption in both cases. Natural gas consumption increased from 33 quadrillion BTUs in 2025 to 42.5 and 42.1 quadrillion BTUs in the energy transition scenarios *S6* and *S7* respectively. Remaining primary energy, primarily petroleum, decreased across both cases from 45.2 quadrillion BTUs in 2025 to 34.4 quadrillion BTUs in *S6* and 34.0 quadrillion BTUs in *S7* by 2050.

2. Natural Gas Production and Consumption Impacts

U.S. natural gas production increased across most cases to maintain projected export volumes. U.S. natural gas consumption, on the other hand, was relatively unchanged across the first four scenarios. Figure 16 plots total U.S. natural gas production, consumption, and export values over time. The LNG export values were identical to those plotted in Figure 3 and are included here as reference.

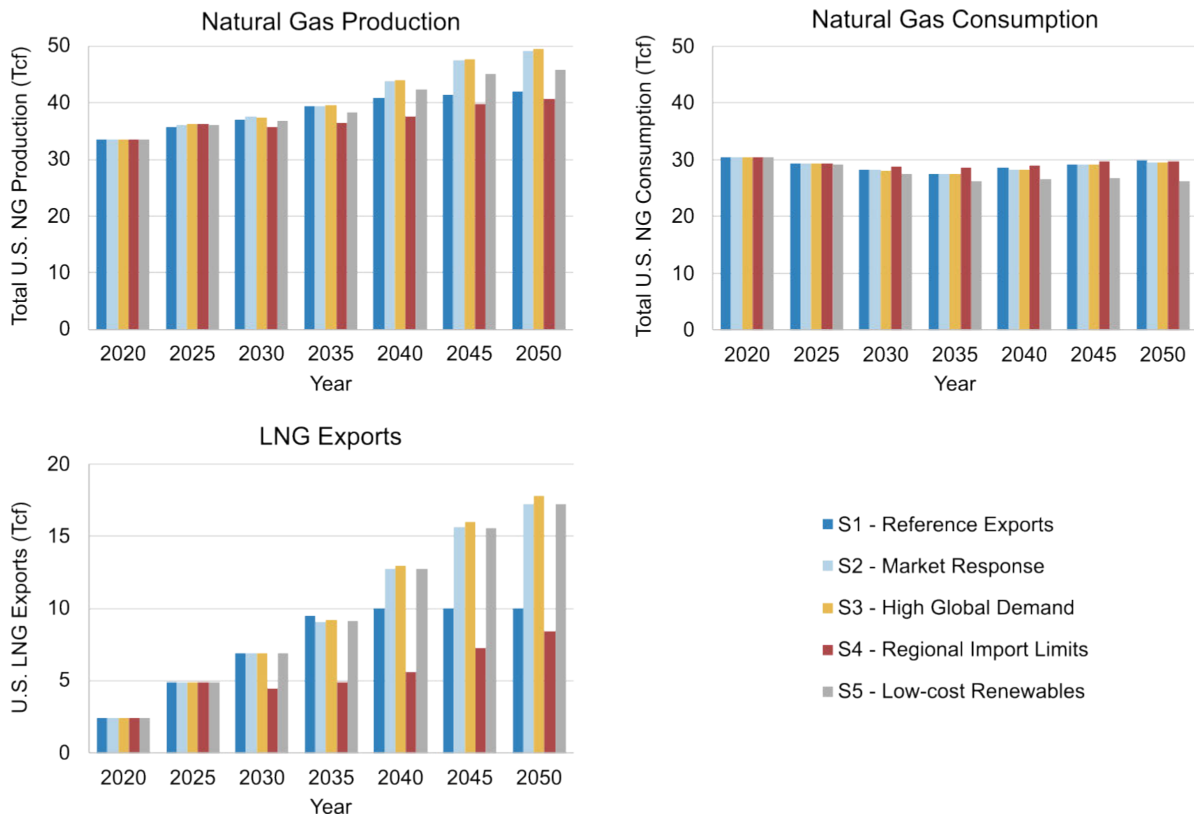


Figure 16. Total U.S. natural gas production, consumption, and export volumes over time, by scenario

From a starting point of 33.5 Tcf (91.5 Bcf/d) of natural gas production in 2020, production in each scenario increased, following a path that correlated with their LNG export curve. Natural gas production in *S1*, *S2*, and *S3* followed a similar trajectory by 2035, reaching 39.4-39.5 Tcf. *S1* production then slowed through 2040 and reached a peak of 42.0 Tcf by 2050. *S2* and *S3* production values accelerated through 2050, reaching 49.0 Tcf and 49.5 Tcf, respectively. Similar to the trends in LNG exports, *S4* production exhibited the lowest values, ending slightly below *S1* at 40.7 Tcf in 2050. *S5* production exhibited the same general path as *S2* and *S3*, but grew more slowly, reaching 38.2 Tcf and 45.7 Tcf in 2035 and 2050, respectively.

The natural gas consumption volumes from *S1-S3* followed similar paths, dipping from 30.5 Tcf in 2020 to 27.4-27.6 Tcf in 2035 before ramping up to 29.6-29.8 Tcf in 2050. Although *S4* had exhibited lower LNG export and natural gas production quantities, the consumption volumes in *S4* remained slightly higher than the volumes in *S1-S3* through most of model years, equalizing with *S1-S3* in the final timestep. *S4* reported 28.5 Tcf of natural gas consumption in 2035 and 29.8 Tcf in 2050. *S5* was the largest outlier with the lowest consumption of 26.2 Tcf in 2035 and almost no change in consumption values between 2035 and 2050.

The lower natural gas production and consumption volumes in *S5* (when compared to *S2* and *S3*) are explained by the effect of low renewables costs on the energy system. *S5* adopted many of the same inputs as EIA's AEO2023-NEMS low zero-carbon technology cost case. These inputs drove down the cost of renewables and caused *S5* to switch from natural gas to cheaper renewable energy sources, affecting both production and consumption. The remaining scenarios showed similar levels of natural gas consumption, but different levels of natural gas production, suggesting that most increases in natural gas production were passing directly to LNG exports.

Figure 17 plots the natural gas production, consumption, and exports for the two net-zero scenarios. Natural gas production in Scenarios *S6* and *S7* is 37.6 Tcf and 37.1 Tcf in 2035, respectively, but quickly rise to 54.7 Tcf and 56.5 Tcf by 2050. *S6* and *S7* exhibited a flatter trend in total consumption through 2040, but reached 41.9 Tcf and 41.5 Tcf, respectively, by 2050. The differences between the two net-zero scenarios were similar to differences observed between *S1* through *S5*: changes in production were correlated with changes in LNG exports, but differences in consumption between scenarios were minimal.

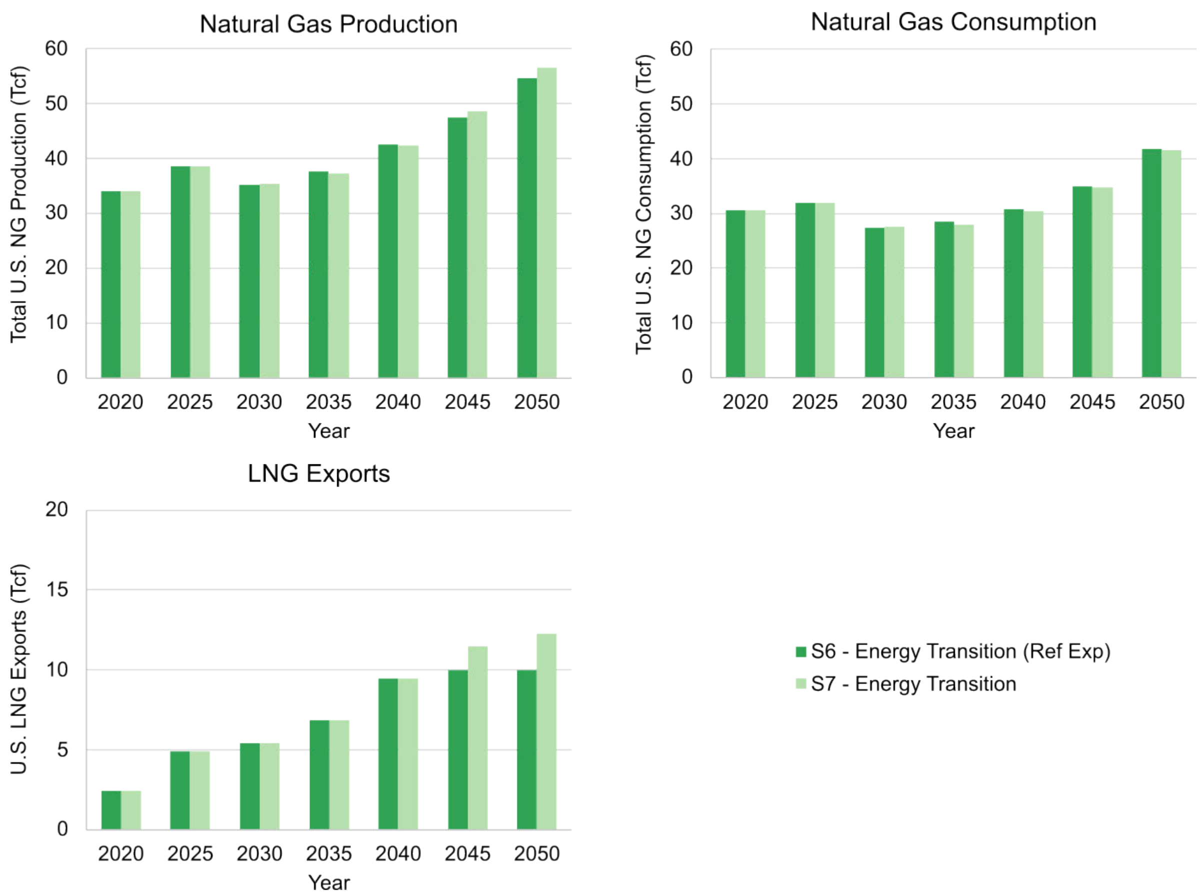


Figure 17. Total U.S. natural gas production, consumption, and export volumes, net-zero scenarios

The rapid increase in natural gas production and consumption for the net-zero scenarios after 2040 came from a substantial increase in natural gas to power direct air capture (DAC) facilities, plotted in Figure B-5 of the appendices. Natural gas consumption accounted for 16.8 Tcf and 16.2 Tcf in 2050 for *S6* and *S7*, respectively. More detail on CO_2 emissions and removals is provided in Section 1.F.5: “U.S. Greenhouse Gas Results”.

3. Natural Gas Henry Hub Prices Impacts

Although total U.S. natural gas consumption volumes were similar across the first five scenarios, the increased LNG exports had a moderate effect on natural gas prices. The natural gas price of the net-zero scenarios rose above the prices from *S1* through *S5*, driven mostly by demand for natural gas to power DAC facilities. Figure 18 plots the natural gas price at the Henry Hub in $2022/Mcf over time for all scenarios.

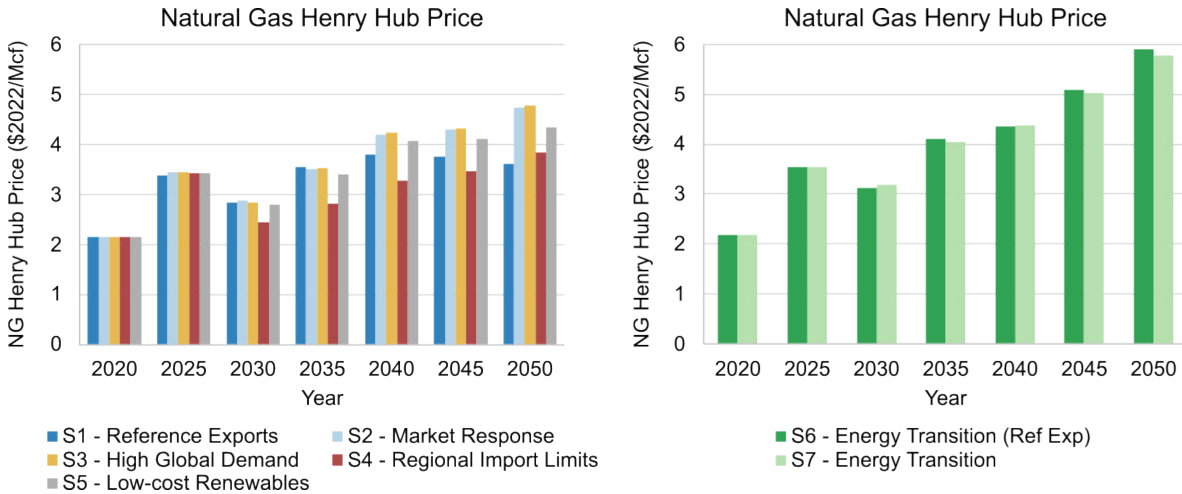


Figure 18. Total U.S. natural gas Henry Hub price by scenario ($2022)

The natural gas price in *S1* increased to a maximum of $3.80/Mcf in 2040 before moderating to $3.61/Mcf in 2050. The natural gas prices in *S2*, *S3*, and *S5* were mostly consistent with the reference case through 2035 but ultimately rose to levels of $4.74/Mcf, $4.79/Mcf, and $4.35/Mcf, respectively, by 2050. The difference in prices correlated with the differences in LNG export curves, while LNG exports in *S1* plateaued after 2035 and saw a drop in natural gas prices. Scenarios *S2*, *S3*, and *S5* all exhibited both increasing exports and prices. *S4* had lower natural gas prices over most of the modeling period, but ultimately exceeded *S1* in 2050 with a price of $3.84/Mcf; the persistent increase in *S4* prices after 2030 was consistent with increases in LNG exports throughout the same time period. Prices remained below $5.00/Mcf for all timesteps in *S1* through *S5*.

The influence of LNG exports on natural gas prices shown in Figure 18 was similar to the effect reported by EIA in their May 2023 "Issues in Focus" report on LNG.[22] The EIA's "Fast Builds Plus High LNG Price" case, which modeled the effect on U.S. energy markets of accelerated construction of LNG infrastructure in an environment with elevated international demand for LNG, reported a 2050 natural gas price of $4.81/MMBtu (equal to $4.64/Mcf) at 48.2 Bcf/d of exports. These values are close to the results from *S2* of $4.74/Mcf at 47.2 Bcf/d of exports and demonstrate good agreement between the two studies on the relationship between LNG exports and natural gas prices.

Overall U.S. natural gas consumption did not change appreciably in response to higher prices, but there were some shifts in consumption behavior on a sector-by-sector basis. These sector-specific differences are presented in greater detail in the Appendix in Figure B-3.

The natural gas price of the net-zero scenarios rose above the prices from *S1* through *S5*, driven mostly by demand for natural gas to power DAC facilities. Natural gas prices for S6 and S7 were similar to prices in *S1* through 2030, but afterwards rapidly increased on a trajectory consistent with the growth of DAC.

[22] U.S. EIA (2023). AEO2023 Issues in Focus: Effects of Liquefied Natural Gas Exports on the U.S. Natural Gas Market. Available at: https://www.eia.gov/outlooks/aeo/IIF_LNG/pdf/LNG_Issue_in_Focus.pdf.

S6 and *S7* reached prices of $5.90/Mcf and $5.77/Mcf, respectively, by 2050. The difference in price between *S6* and *S7* was within the tolerance of the model.

4. U.S. Macroeconomic Outcomes

While NEMS has rich detail about the energy system, a separate macroeconomic activity module (MAM) provides projections of economic drivers underpinning NEMS' energy supply, demand, and conversion modules. The MAM incorporates IHS Markit's (now S&P Global's) model of the U.S. economy, along with EIA's extensions of industrial output, employment, and models of regional economies. The S&P Global module is modified to include EIA's assumptions on key assumptions, such as world oil price, yielding a baseline trajectory of the economy. The baseline cannot appropriately respond to the wider economic changes in the net-zero scenarios, so such analysis is not included here. Within a NEMS scenario, feedback from the other NEMS modules includes:

- Production of energy, including coal, natural gas, petroleum, biomass, and other fuels;
- Trade in energy, including net exports coal, petroleum, natural gas, and biofuels;
- Total and end-use demand for energy, including sales of electricity;
- Consumer spending on energy, disaggregated to fuel oil motor fuels, electricity, natural gas, and highway consumption of gasoline;
- Energy prices, including a price index for consumer prices and wholesale prices; and
- Industrial production indices for oil and gas extraction and coal mining.

Since the MAM does not track individual projects, GDP estimates do not include economic activity associated with specific export facilities and thus the impacts are approximate.

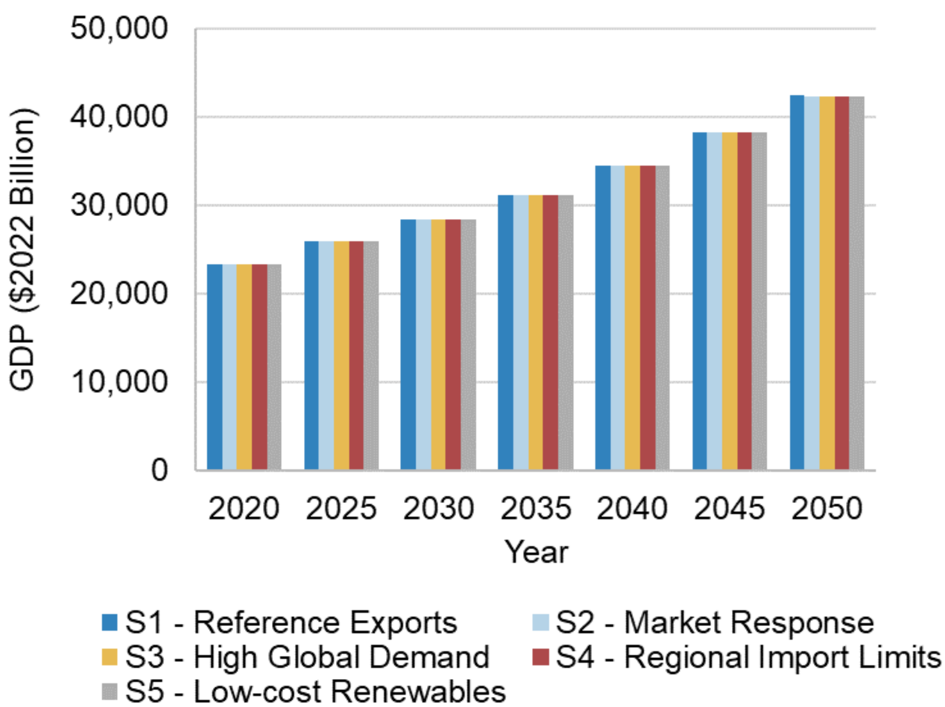


Figure 19. U.S. real GDP changes

As shown in Figure 19, U.S. GDP growth rate through 2045 remained essentially constant across all five scenarios, increasing at 1.9% annually. Higher natural gas exports resulted in higher prices, reducing economic activity in some sectors but increasing in others. The impact of increased LNG exports was positive on GDP by less than 0.1% across scenarios the through 2045. Accelerating natural gas prices in the last five years of the projection period in S2 reduced consumption on other products and tended to slightly reduce the overall rate of economic growth relative to *S1*. Overall, GDP changes in 2050 relative to 2020 were within 0.3% across all five scenarios.

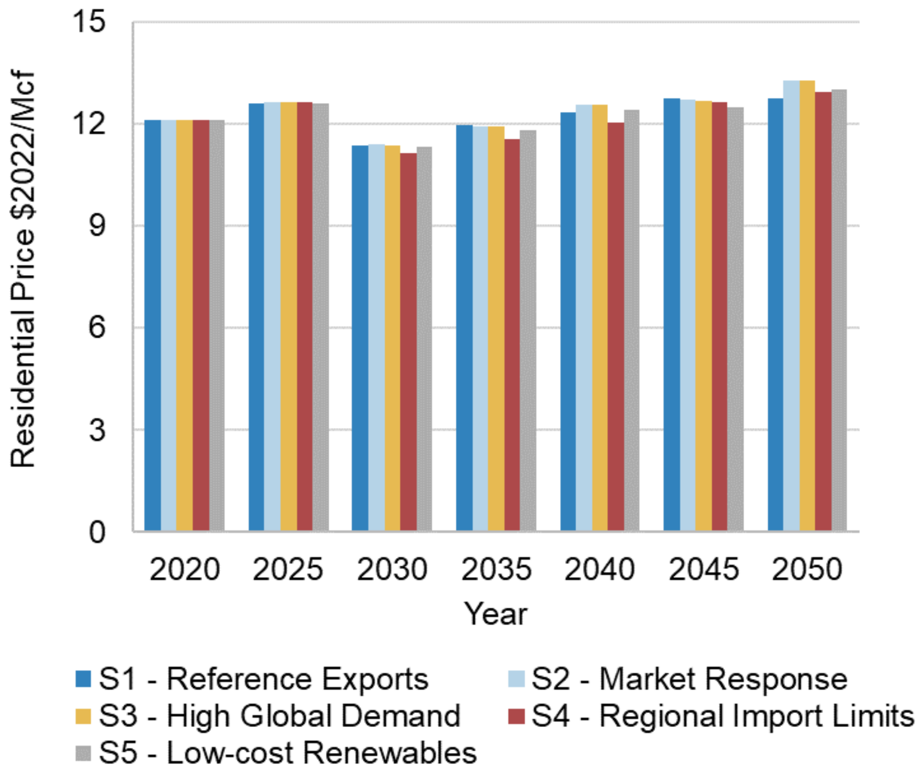


Figure 20. U.S. residential natural gas prices

Figure 20 shows the residential natural gas price in each of the five key scenarios. In 2050, natural gas prices in *S3* (when exports are the highest) were 4% higher than S1, when exports were the lowest. Overall, natural gas price differences between the scenarios were generally close to 1-2% across the scenarios.

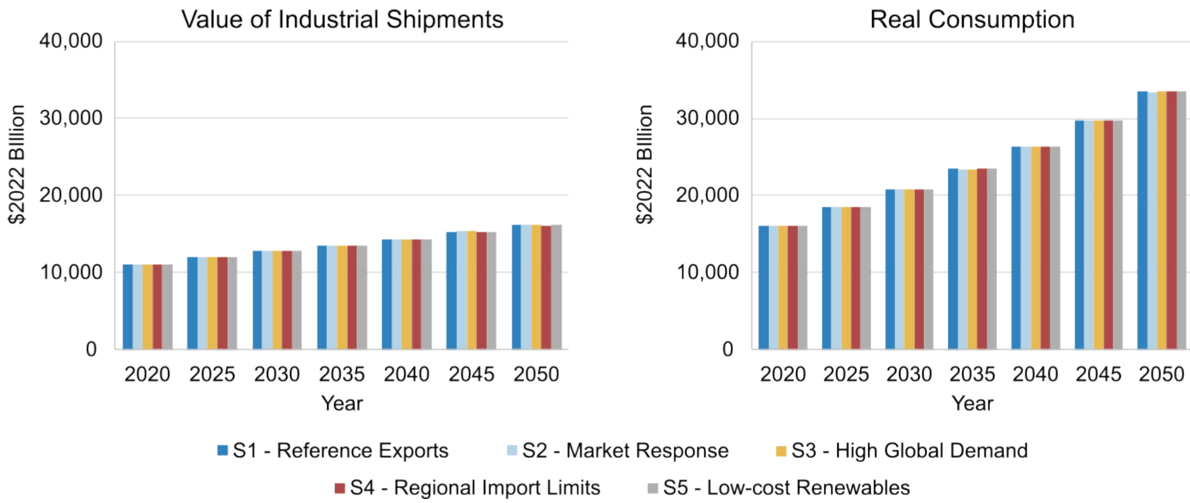


Figure 21. U.S. value of industrial shipments and real consumption

One component of GDP tracked by NEMS is the value of industrial shipments, shown in Figure 21. Industrial processes are sensitive to natural gas prices, which were generally higher than *S1*. However, increased production, processing, and transportation of natural gas requires additional equipment which tends to increase industrial shipments. Overall, NEMS showed a very slight increase in the value of industrial shipments in *S2* relative to *S1* of 0.2% in 2050. The value declined in S4 vs S1, reflecting lower natural gas production and exports.

The NEMS analysis shows NG exports could benefit consumers through increased labor income and the return on capital expended on facilities to produce and export the commodity. Exports increased the value of the dollar, decreasing the cost of some imports. However, increased demand for natural gas, including exports, raised the price of natural gas and the costs of products that require natural gas as an input. This can be observed in the change in aggregate consumption which is another component of GDP. When energy prices rise, consumers must pay more for natural gas, but purchases of other goods decrease. Across all the scenarios, this effect was small, and, while wealth transfers may occur between consumers as some groups benefit more than others through increased production, this was not reflected in the aggregate output of the model. Changes across all the scenarios were essentially flat. Overall, by 2050 consumption changes were less than 0.2%.

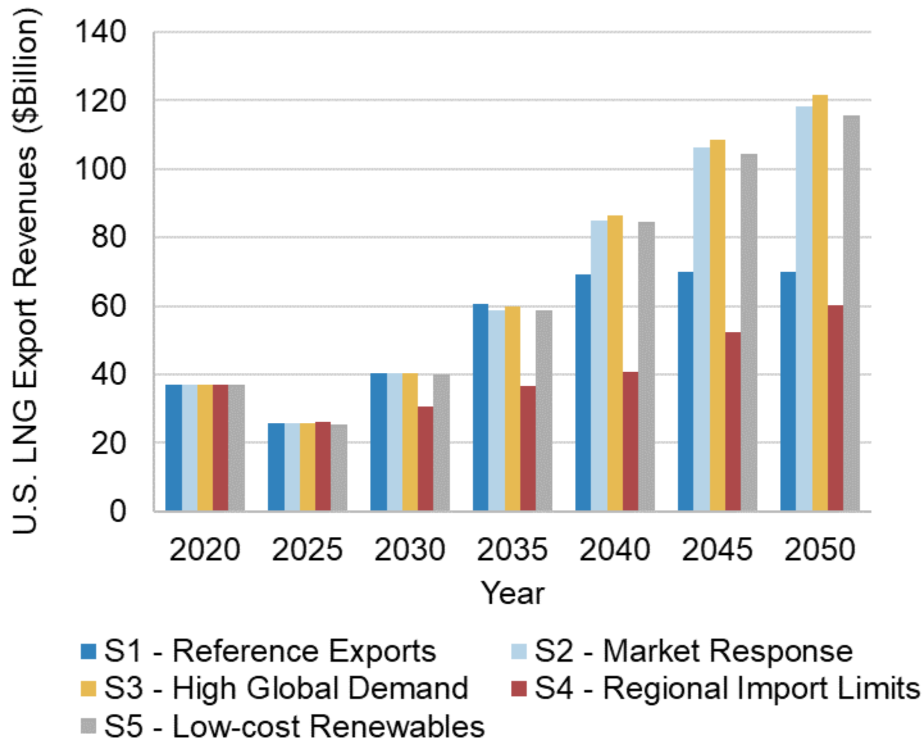


Figure 22. U.S. LNG export revenues

In a fully competitive market, the delivered price of LNG should be sufficient to fully accommodate the cost of production, liquefaction, and transportation of natural gas. Since much of this activity occurs domestically, it is a rough proxy for economic activity engendered by LNG exports. A representative price would be the price of imports to the EU. Figure 22 shows estimates of export revenues as the product of the LNG export volumes and the EU LNG price.

5. U.S. GHG Results

AEO2023-NEMS tracks CO_2 emissions from the combustion and use of fossil fuels. These CO_2 emissions did not change significantly between scenarios in response to varying LNG export levels. Figure 23 plots CO_2 emissions from fossil fuels for *S1* through *S5*.

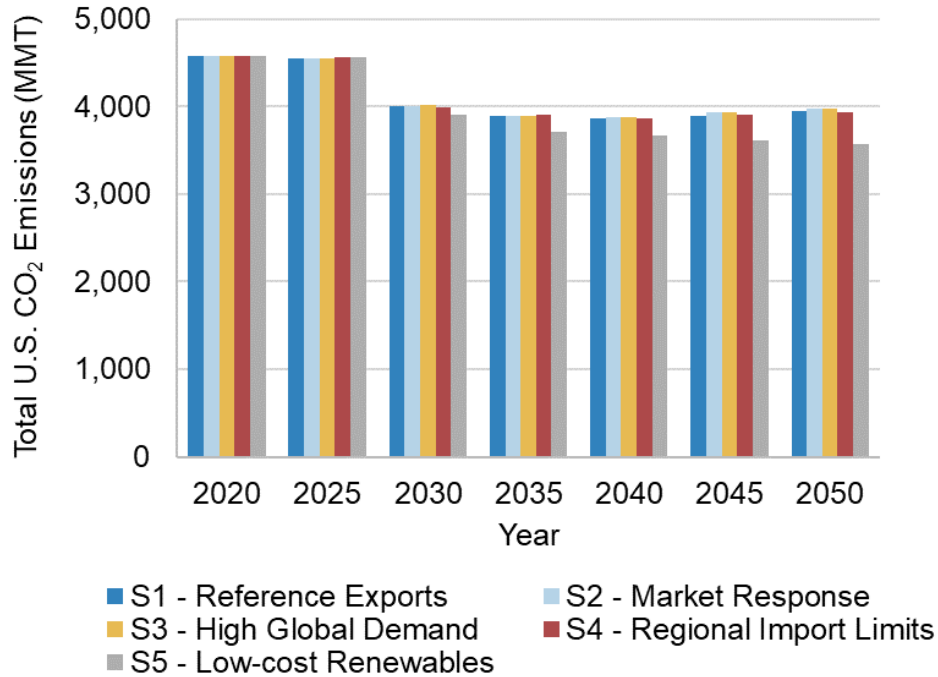


Figure 23. Total U.S. CO_2 emissions from fossil fuel combustion

From a starting point of 4,580 MMT CO_2 emissions in the U.S. in 2020, the first four scenarios declined to between 3,990 and 4,020 MMT CO_2 in 2030 and followed a flatter trajectory to 3930-3980 MMT CO_2 in 2050. There was a weak connection between LNG exports and CO_2 emissions: cases with the highest exports (*S2* and *S3*) had slightly higher CO_2 emissions levels in 2050 of 3970 and 3980 MMT, respectively, whereas cases with lower exports (*S1* and *S4*) reported respective CO_2 emissions of 3040 and 3030 MMT. The relationship was small, however, and accounted for only a 1% difference in emissions. The small differences between the first four scenarios were consistent with the relatively unchanged natural gas consumption volumes observed in Figure 16. *S5* was an outlier, continuing to decrease through 2030 (3910 MMT CO_2) and reaching 3570 MMT CO_2 emissions by 2050. The lower emissions from *S5* were explained by the assumptions used for low renewable costs rather than by changes in LNG exports.

S6 and *S7* were modeled in FECM-NEMS, which endogenously calculated some additional emissions that AEO2023-NEMS is missing (most relevant being CH_4 leakage from natural gas production and processing infrastructure). To retain consistency between the two models, only the CO_2 emissions reported by FECM-NEMS were included in the analysis and used to define the net-zero GHG scenarios. The remaining non-CO_2 emissions (which still contributed to the overall net-zero GHG cap) were calculated endogenously within GCAM and used in FECM-NEMS as an exogenous input.

Figure 24 plots the CO_2 emissions and removals for *S6* and *S7*. Both scenarios had both lower emissions than *S1* and significant amounts of CO_2 removals, reaching net-zero by 2050.

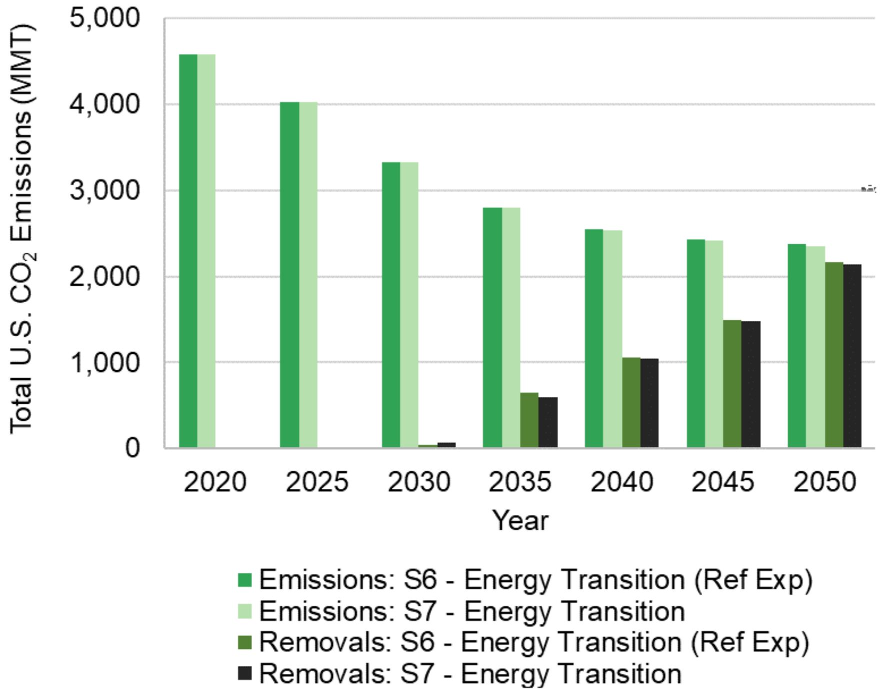


Figure 24. Total U.S. CO_2 emissions from fossil fuel combustion and removals, S6 and S7

CO_2 emissions from *S6* and *S7* began at 4,580 MMT and declined continuously through 2050, ending at 2,370 and 2,350 MMT CO_2, respectively. These declines were primarily driven by electrification of broad sections of the economy with a combination of renewables and CCS. The decline in emissions was accompanied by an increase in removals, which started growing rapidly in 2030 and eventually reached 2,160 MMT CO_2 for *S6* and 2,130 MMT CO_2 for *S7* in 2050. The majority of removals (87-89% by 2050) came from DAC, with the remainder coming from H_2 production with biomass and BECCS. The specific breakdown of removal technologies is explored in Section D of Appendix B. While the removals did not completely cancel out the 2,350-2,370 MMT of CO_2 emissions, the difference is balanced out by the non-CO_2 emissions calculated within GCAM and used as exogenous inputs, which were net negative.

G. NETL Life Cycle Analysis

The goals of the LCA component of this project were twofold: first*,* to help contextualize how the other results of this study (i.e., NEMS and GCAM models) connect to past studies of U.S. natural gas and LNG operations and, second, to leverage the results of the other models to quantitatively represent the international global warming potential (GWP) consequences from changes in quantities of U.S. exported LNG.

In support of the first goal, the following work was completed:

- Assessed whether NEMS results suggested significant changes in domestic supply (and thus, resulting in potential future upstream GWP intensity or emissions changes)
- Compared and aligned GCAM and NETL results to create a representation of the global natural gas supply chain is consistent with existing NETL natural gas LCA studies.

In support of the second goal, the following work was completed:

- Developed a quantitative "market effect adjustment factor" that represents the consequences of additional export volumes of U.S. LNG, such as how additional available quantities of natural gas led to changes in the energy sectors of countries that purchase the LNG. These consequential effects were estimated by tracking differences in global GHG emissions and quantities of U.S. LNG exported from the GCAM model scenarios and assessed in comparison to existing NETL quantitative estimates of the upstream natural gas production.

In this project, the NEMS and GCAM models sought to represent economic and environmental changes associated with the defined changes in U.S. LNG exports. The GCAM model estimated global GHG emissions effects, including emissions associated with upstream natural gas. To compare the GCAM results with past NETL work used by DOE in support of natural gas and LNG export decisions, NETL assessed and aligned the emissions estimates of the two models.

1. Assessment of NEMS Domestic Natural Gas Production by Region

The NEMS modeling focused on domestic changes that would be expected to occur in the seven scenarios modeled. NETL evaluated the regional sources of natural gas using outputs from NEMS to compare them to the mix of regions NETL uses in existing assessments of upstream natural gas emissions.

As shown in Appendix C, the NEMS results suggested only modest changes in the production mix by region and thus would not be expected to substantially change the domestic average GHG intensity per MJ of natural gas produced compared to previous analyses. As such, no regional adjustments were made to the results.

2. Comparison of GCAM and NETL Estimates of GHG Emissions of the Natural Gas sector

As discussed above, the GCAM model represents economic activity (and associated GHG emissions) by sectors and technologies, and their respective inputs and outputs, for regions, years, and scenarios. However, only a subset of these was relevant to the scope of the natural gas LCA-focused effort.

Only three sectors in the GCAM model include greenhouse gas emissions of the natural gas sector: *natural gas*, *gas pipeline*, and *other industrial energy use* (see Appendix C for more detail). Using the basis of process stages as represented in the NETL Natural Gas model, Figure 25 shows the relevant GCAM sectors that have associated 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 were represented.

As summarized in Figure 25, all stages of the NETL LCA are explicitly represented in GCAM except for Ocean Transport, which was included as part of other industrial energy use but could not be separated out for this analysis. As a result, the comparison in this report was focused on a comparison of emissions from production of natural gas in the U.S. through delivery to a large end user rather than LNG delivered around the world.

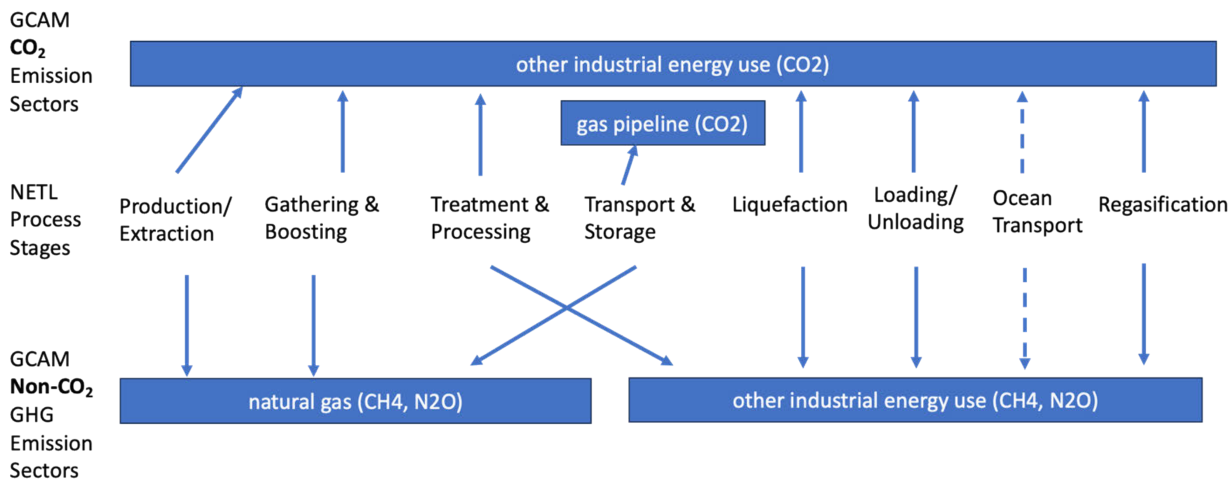


Figure 25. Mapping of NETL natural gas stages to GCAM sectors

Quantitative values of emissions intensities in the year 2020 of the various GCAM sectors for the USA region for the three natural gas-relevant sectors are listed and compared to NETL natural gas model results in Appendix C. Note that in order to compare NETL and GCAM results, NETL model results were regenerated using LHV basis and differ from those published (as HHV by default) in the report.

Overall, the estimated upstream emissions for the USA in the GCAM model were about 8.52 g CO_2e/MJ (on an IPCC AR6 100-year basis), which is slightly higher than those of the NETL model for the boundary of production through transmission to large end user (8.18 g CO_2e/MJ, LHV basis). Using the relationship between those estimates, emissions results in the three GCAM natural gas sectors were adjusted by a factor of 8.18/8.52, or 0.96 (a 4% reduction) to maintain consistency with past NETL studies. This adjustment factor was used for all regions and for all years in the model. Similar adjustment factors were found for IPCC AR6 20-year and IPCC AR5 100-year and 20-year bases (see Appendix C for further details).

For context, in the GCAM results for *S1* in Year 2020, total global GHG emissions are approximately 53,000 Tg. The NETL adjustment post-processing of the GCAM model results on the IPCC AR6 100-year basis of the *gas pipeline* and *natural gas* sectors reduces emissions by about -7 and -35 Tg CO_2e, respectively, when considering those of *S1* in the Year 2020. Post-processing adjustments of the GCAM model results of the *other industrial energy use* sector reduce emissions by about -10 Tg CO_2e when considering those of *S1* in the Year 2020. The adjustments for these three sectors needed to align with past NETL studies have the cumulative effect of reducing estimated emissions from the GCAM model by about 0.2% (in *S1* in the Year 2020).

This same process was undertaken for different IPCC GWP values, and the resulting alignment tables and adjustment factors are provided in Appendix C.

3. Market Adjustment Factor Results

Market adjustment factors (MAF) quantitatively estimate the consequential effect on global emissions as a function of U.S. LNG exported. MAFs for *S2* were estimated versus a baseline of *S1*, while the MAF for *S7* was estimated versus a baseline of *S6* given the significantly different global economy modeled in these scenarios.

MAFs were calculated using the post-processed NETL-adjusted GCAM results described previously. The MAF was calculated for each scenario by aggregate annual values over the time horizon of the model (i.e., the MAF for *S2* versus *S1* was defined as 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 same period).

All MAFs were found using a variety of IPCC Assessment Report GWP values over 20- and 100-year time horizons, and with the raw and post-processed NETL adjusted GCAM results. MAF results from the IPCC Sixth Assessment Report on a 100-year time horizon are presented, and results for other IPCC Assessment Report and time horizons (and all raw GCAM results) are shown in Appendix C.

Table 4 shows the MAFs for *S2* (vs. *S1*), which varied from -5.34 to -5.35 g CO_2e/MJ on a 100-year time horizon (LHV basis). Also included is a summary reminder of the differences in the modeled scenarios (e.g., where *S1* is the baseline and *S2* added an economic solution for LNG exports, making a direct comparison of the two appropriate).

Table 4. Market Adjustment Factors for S2 vs. S1 (IPCC AR6, 100 year)

	Results (g CO_2e/ MJ)		
MAF Case	GCAM	GCAM with LHV NETL adjustment	Scenario Difference
S2* vs. *S1	-5.34	-5.35	Adds economic solution for LNG exports.

Table 5 shows market adjustment factors for *S7* vs. *S6*, both of which represented significantly different energy and economic investments in support of a low-carbon economy through climate policies. The *S7* MFAs vary from -2.81 to -3.01 on a 100-year time horizon (LHV).

Table 5. Market Adjustment Factors for S7 vs. S6 (IPCC AR6, 100 year)

	Results (g CO_2e/ MJ)		
MAF Case	GCAM	GCAM with LHV NETL adjustment	Scenario Difference
S7* vs. *S6	-3.01	-2.95	S6 1.5°C pathway, economic solution for LNG exports

4. Interpretation of Market Adjustment Factor Results

On an IPCC AR6 100-year basis, for *S2-S1*, the MAF result was approximately -5.4 g CO_2e/MJ (LHV). For purposes of comparison, NETL estimated natural gas upstream emissions prior to delivery to a large industrial end user (like an LNG terminal) are 7.4 g CO_2e/MJ (HHV). The MAF indicated that as U.S. LNG exports increased, the induced global market effects result in an overall reduction in GHG emissions that is about 70% of the estimated upstream emissions associated with production through delivery of the natural gas to a large industrial end user in the U.S.

The MAF result for *S7-S6* was about -3 g CO_2e/MJ (LHV). In a decarbonizing world, the overall reduction in emissions was 56% of the estimated upstream emissions associated with production through delivery of the natural gas to a large industrial end user in the U.S. This is consistent with the idea that as the global economy decarbonizes, the induced global decarbonization benefit of increased U.S. LNG will be less. Overall, both of these results were consistent with the overall GCAM results that increased U.S. exports did not lead to increased global GHG emissions. Global changes in GHG emissions were constant to slightly negative as U.S. natural gas exports increased and global energy demand increased. The GHG reductions represented by the negative MAF were not so large that U.S. LNG should be regarded as a global climate reduction strategy but, at the same time, a negative MAF suggested that increased U.S. LNG exports could be compatible with global decarbonization efforts. A positive MAF would suggest U.S. LNG was leading to overall increased global emissions.

The results were aggregated in relation to estimated future volumes of exported LNG from the U.S. 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 natural gas sources would directly lead to lower GHG emissions results when supplied around the world.

VI. Conclusions

The purpose of this study was to examine the potential global and U.S. energy system and greenhouse gas (GHG) emissions implications of a wide range of economic levels of U.S. LNG exports. The study comprised three coordinated analyses: 1) **a Global Analysis** to explore a wide range of scenarios of U.S. LNG exports under alternative assumptions about future socioeconomic growth, regional preferences for domestically produced natural gas, pace of technological change in competing technologies (e.g., renewables), and countries' announced GHG emissions pledges and policies; 2) **a U.S. Domestic Analysis** of the implications of the various U.S. LNG export levels derived from the Global Analysis for the supply and demand of natural gas within the U.S. and the U.S. economy; and 3) **a Life Cycle Analysis** to examine the life cycle emissions implications of the various levels of U.S. LNG exports derived from the Domestic and Global analyses. A number of key insights from this study are summarized below. Table 6 includes a summary of the key results across scenarios.

1. Across all modeled scenarios, U.S. LNG exports continue to grow beyond current operational export capacity (14.3 Bcf/day) through 2050. In addition, U.S. natural gas production grow beyond current levels through 2050. Across all the scenarios, LNG exports range from 23-47 Bcf/day. The range of U.S. LNG exports from this study is consistent with the U.S. EIA's analysis (15-48 Bcf/day.)[23] Compared to a scenario in which U.S. LNG exports follow the Reference Case from the AEO2023 (*S1*, growing to 27.3 Bcf/day by 2050), a scenario that assumes economically-driven LNG export levels (*S2*) results in significant growth in U.S. LNG exports to 47 Bcf/day by 2050. The availability of additional U.S. natural gas at competitive prices in the global natural gas market in the latter scenario (*S2*) results in a reduction in production, reduction in LNG exports, increase in LNG imports, and reduction in pipeline trade outside of the U.S.
2. Global natural gas consumption increases only slightly (<1 percent) under a scenario with increased availability of U.S. natural gas in the global market that reflects economically driven

[23] U.S. EIA. (2023). Issues in Focus: Effects of Liquefied Natural Gas Exports on the U.S. Natural Gas. Available at: Markethttps://www.eia.gov/outlooks/aeo/IIF_LNG/

LNG export levels (*S2*) compared to the reference scenario (*S1*), as the availability of additional U.S. natural gas in the global market does not materially affect the competitiveness of natural gas relative to other fuels globally. Instead, it results in a shift in the regional composition of natural gas production and trade. The majority of U.S. natural gas substitutes for other global sources of natural gas.

3. U.S. natural gas prices as measured at the Henry Hub increases modestly when comparing a scenario that reflects global market demand for exports (*S2*) to the reference scenario (*S1*). Across those scenarios, 2050 Henry Hub prices are projected to increase from $3.61/Mcf to $4.74/Mcf, both of which are less than the reference 2050 price expected in the most recent study DOE[5] commissioned on the economic impacts from U.S. LNG exports in 2018.
4. U.S. residential prices are projected to be 4% higher in 2050 when comparing a scenario that reflects global market demand for exports (*S2*) to the reference scenario (*S1*). In none of the scenarios did the change in residential prices exceed 4% and generally by substantially less.
5. The value of industrial shipments remains essentially unchanged (increasing less than 0.1% by 2050) when comparing a scenario that reflects global market demand for exports *(S2*) to the reference scenario *(S1).* The impact of increased LNG exports on GDP is essentially flat, positive by less than 0.1% across scenarios through 2045 while all changes are within 0.3% in 2050.
6. Even though U.S. LNG exports continue to grow beyond existing and planned nameplate capacity across scenarios *S1* through *S5* to 23-47 Bcf/day by 2050, global and U.S. GHG emissions do not change appreciably. Global emissions in these scenarios range from 47.5-50.3 $GtCO_2e$ and U.S. emissions range from 4.3-4.6 $GtCO_2e$ across these scenarios.
7. The induced global market effects of a case that reflects global market demand for exports (S2) compared to the reference case (*S1*) are equivalent to an overall reduction in GHG emissions of about 70% of the estimated upstream emissions associated with production through delivery of the natural gas to a large industrial end user (e.g., to an LNG export facility) in the U.S.
8. When compared to the other scenarios, *S6* and *S7* – in which countries are assumed to achieve their GHG emissions pledges and pursue ambitious GHG mitigation policies consistent with limiting global warming to 1.5°C – are characterized by a global transition resulting in lower in natural gas, coal, and oil consumption without CCUS; higher deployment of gas, coal and biomass with CCUS, and renewables; higher deployment of carbon dioxide removal strategies; and lower overall energy consumption. While in scenario *S6*, in which U.S. LNG exports are limited to the values from the AEO2023 Reference case (by design) and grow to 27.34 Bcf/day by 2050, *S7* assume economically-driven outcomes resulting in U.S. LNG exports growing to 34 Bcf/day by 2050. The higher growth in U.S. LNG exports in *S7* compared to *S6* is driven by increased global demand for natural gas with CCUS in the power and industrial sectors. Similar to the comparison between *S1* and *S2*, the availability of additional U.S. LNG in *S7* in the global natural gas market results in a very small increase in natural gas consumption, reduction in production, reduction in LNG exports, increase in LNG imports, and reduction in pipeline trade in the rest of the world compared to *S6*. Furthermore, with the higher U.S. LNG exports in *S7* compared to *S6*, U.S. natural gas prices are essentially unchanged within modeling tolerance, reaching $5.90/Mcf in *S6* and $5.77/Mcf in *S7* by 2050.

Table 6. Key Results for U.S. and globe in 2050 across scenarios

Scenarios	U.S. LNG Exports (Bcf/d)	U.S. NG Henry Hub Price ($2022/Mcf)	US Net GHG Emissions ($GtCO_2e$)	Global Net GHG Emissions ($GtCO_2e$)
S1	27.3	$3.61	4.5	48
S2-S5	23.1 – 48.7	$3.84-$4.79	4.3-4.6	47-50
S6-S7	27.3 – 33.6	$5.77-$5.90	0	17

APPENDIX A: GLOBAL ANALYSIS AND DESCRIPTION OF GCAM

A. Additional detail about GCAM's energy system

GCAM's energy system contains representations of fossil resources (coal, oil, gas), uranium, and renewable sources (wind, solar, geothermal, hydro, biomass, and traditional biomass) along with processes that transform these resources to final energy carriers (electricity generation, refining, hydrogen production, natural gas processing, and district heat) which are ultimately used to deliver goods and services demanded by end use sectors (residential buildings, commercial buildings, transportation, and industry). Each of the sectors in GCAM includes technological detail. For example, the electricity generation sector includes several different technology options to convert coal to electricity such as pulverized coal with and without carbon capture, utilization, and storage (CCUS), and coal integrated gasification combined cycle (IGCC) with and without CCUS. The full list of technologies in various sectors in GCAM is documented in the GCAM documentation page (http://jgcri.github.io/gcam-doc/).

In every sector within GCAM, individual technologies compete for market share based on the levelized cost of a technology. The cost of a technology in any period depends on (1) its exogenously specified non-energy cost, (2) its endogenously calculated fuel cost, and (3) any cost of emissions as determined by the climate policy. The first term, non-energy cost, represents capital, fixed and variable operating and maintenance (O&M) costs incurred over the lifetime of the equipment (except for fuel or electricity costs), expressed per unit of output. For example, the non-energy cost of coal-fired power plant is calculated as the sum of overnight capital cost (amortized using a capital recovery factor and converted to dollars per unit of energy output by applying a capacity factor), fixed and variable operations and maintenance costs. The second term, fuel or electricity cost, depends on the specified efficiency of the technology, which determines the amount of fuel or electricity required to produce each unit of output, as well as the cost of the fuel or electricity. The various data sources and assumptions are documented in the GCAM documentation page (http://jgcri.github.io/gcam-doc/). The prices of fossil fuels and uranium are calculated endogenously. Fossil fuel resource supply in GCAM is modeled using graded resource supply curves that represent increasing cost of extraction as cumulative extraction increases. Wind and rooftop PV technologies include resource costs that are also calculated from exogenous supply curves that represent marginal costs that increase with deployment, such as long-distance transmission line costs that would be required to produce power from remote wind resources. Utility-scale solar photovoltaic and concentrated solar power technologies are assumed to have constant marginal resource costs regardless of deployment levels.

In GCAM, technology choice is determined by market competition. The market share captured by a technology increases as its costs decline, but GCAM uses a logit model of market competition. This approach is designed to represent decision making among competing options when only some characteristics of the options can be observed and avoids a "winner take all" response.

B. Additional detail about scenario design

Table A-1. Detailed assumptions in the S4: Regional Import Limits scenario

Region Type	GCAM Regions	High-level target / sanction
Developed countries, natural gas importers with sufficient domestic resources	EU-12, EU-15, Europe_Eastern, Europe_Non_EU	Reduce gross imports to 90% by 2035 and zero by 2040
Developed countries, natural gas importers with low domestic natural gas resources	Japan, South Korea, Taiwan	Maintain current import dependence through 2050
Developing countries, natural gas importers	Brazil, China, India, Pakistan, Southeast Asia, Mexico, South Africa	Maintain current import dependence through 2050
Natural gas exporters	USA, Africa_Eastern, Africa_Northern, Africa_Southern, Africa_Western, Australia_NZ, Canada, Central America and Caribbean, Central Asia, European Free Trade Association, Indonesia, Middle East, South America_Southern, South America_Northern, South Asia, Colombia, Argentina	Reduce gross imports to 90% by 2035 and zero by 2040
Russia	Russia	Same as *S2*

C. Additional GCAM results

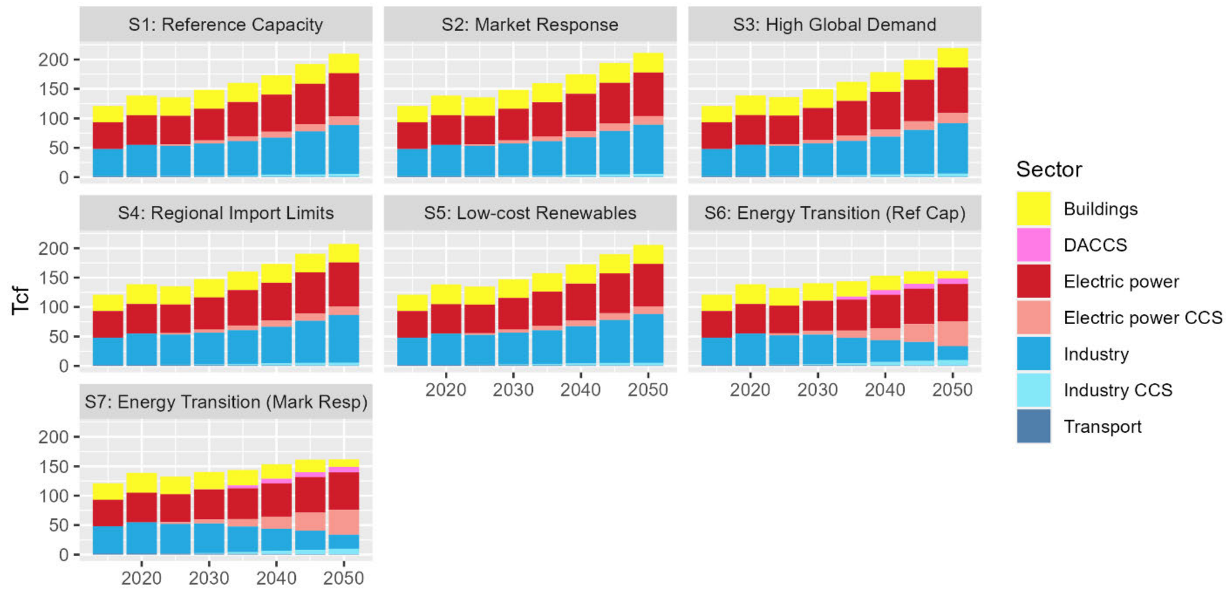


Figure A-1. Global natural gas consumption by sector across all scenarios

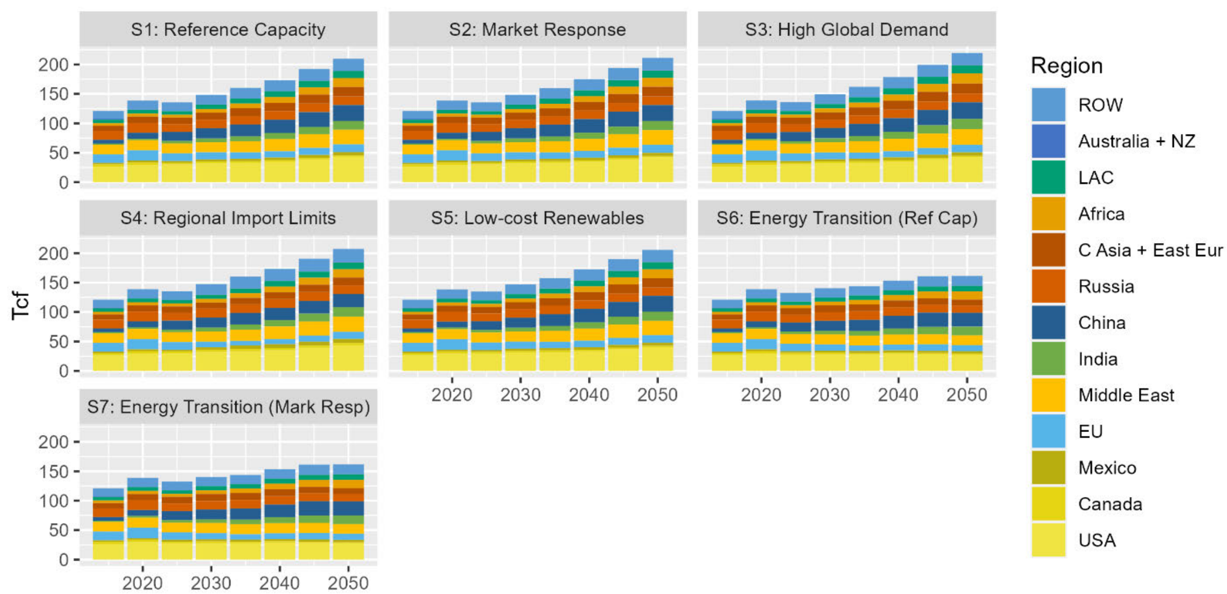


Figure A-2. Global natural gas consumption by region across all scenarios

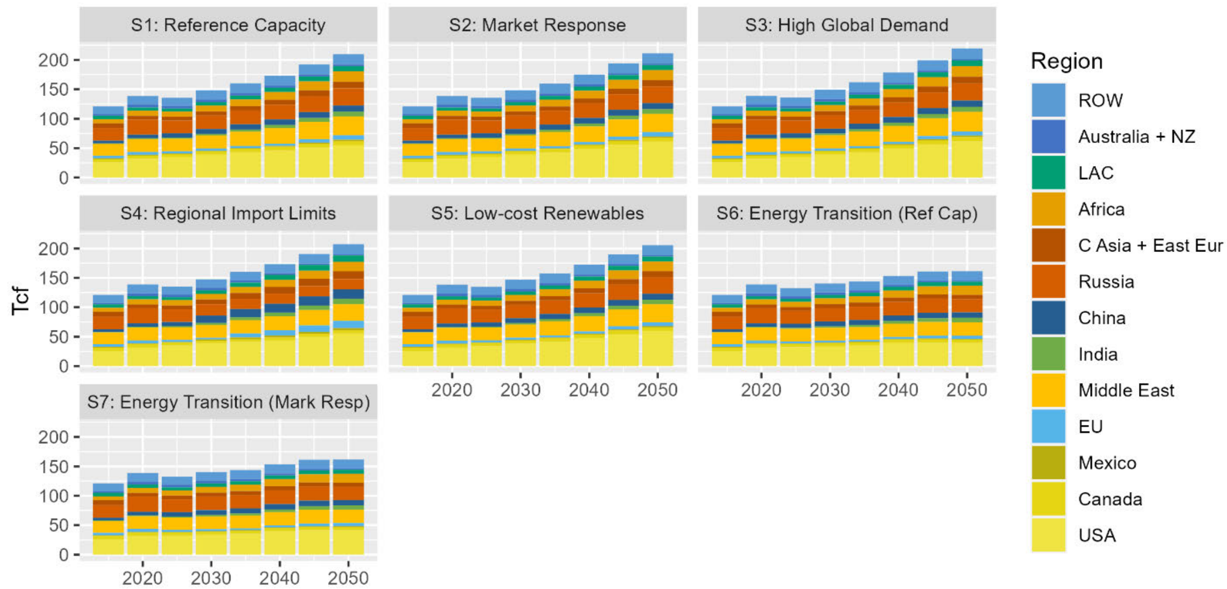


Figure A-3. Global natural gas production by region across all scenarios

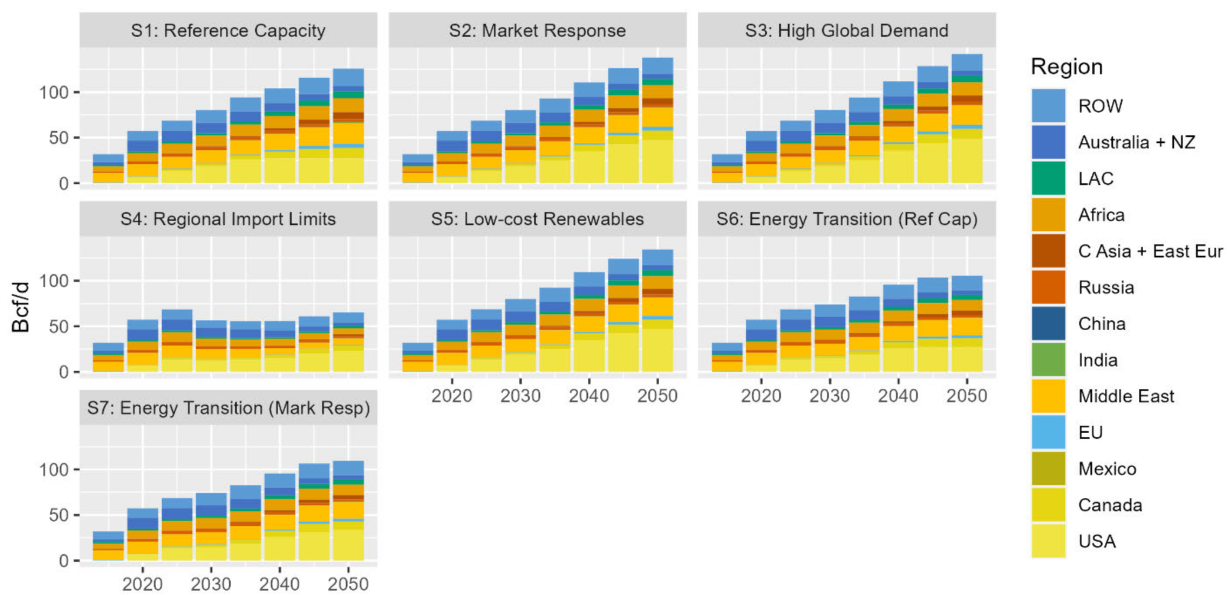


Figure A-4. Global LNG exports by region across all scenarios

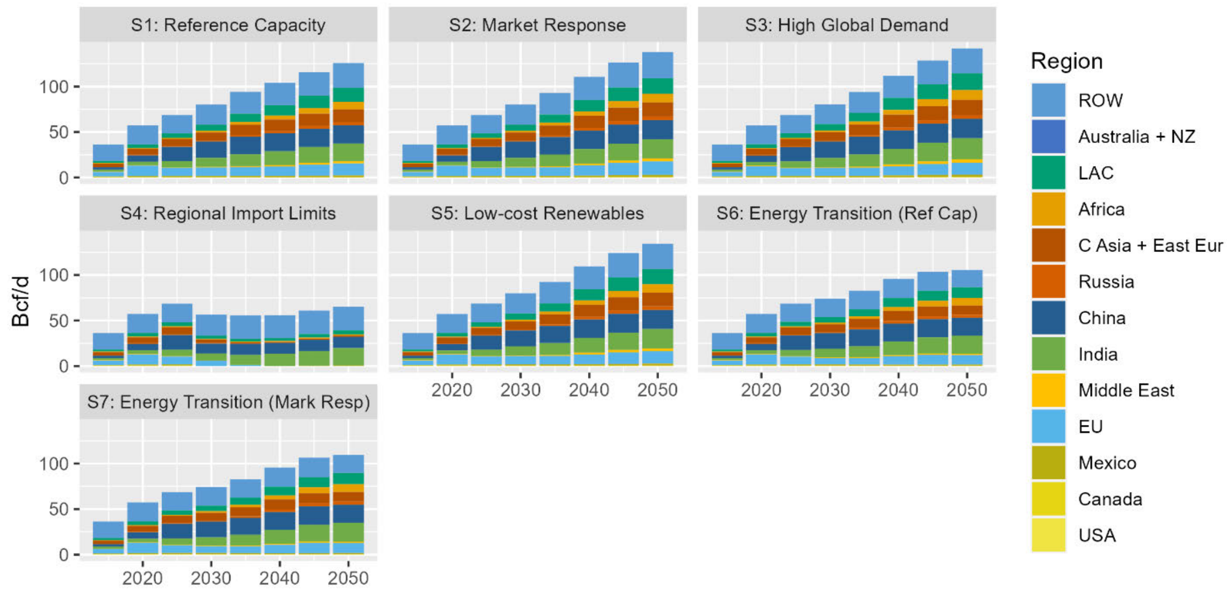


Figure A-5. Global LNG imports by region across all scenarios

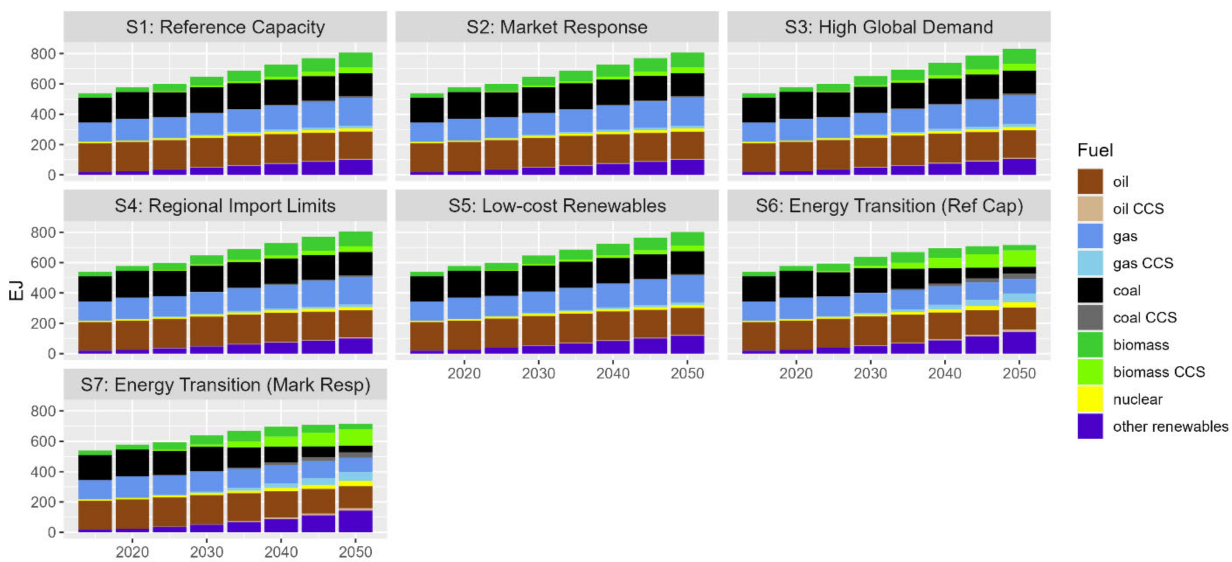


Figure A-6. Global primary energy consumption by fuel across all scenarios

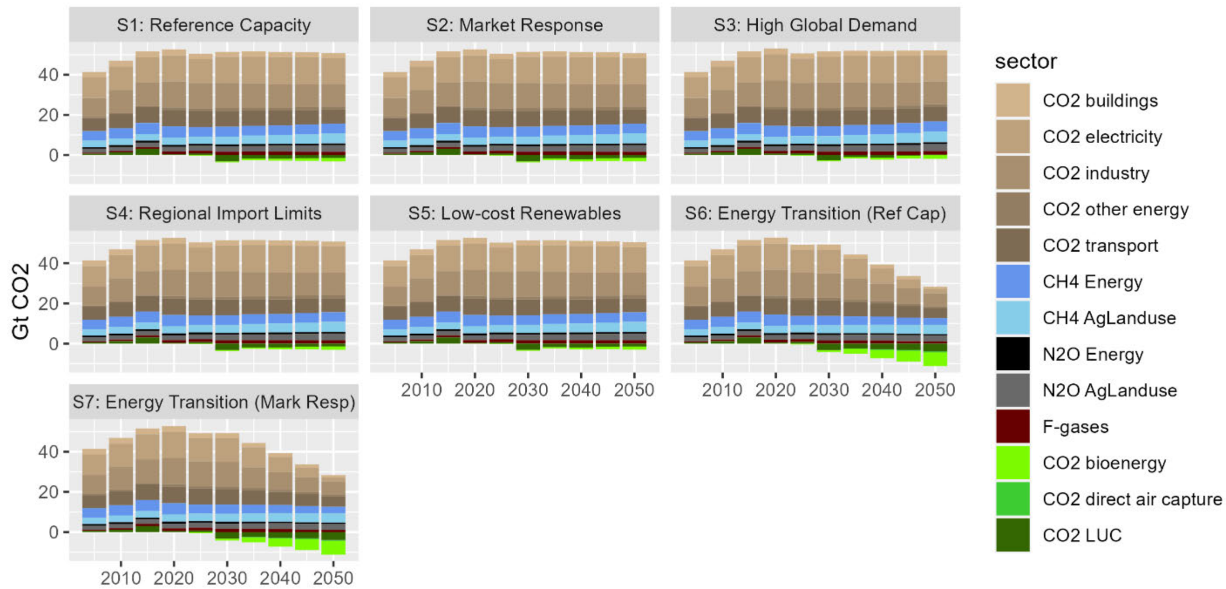


Figure A-7. Global GHG emissions by sector across all scenarios

Appendix B: U.S. Analysis and Description of AEO2023-NEMS and FECM-NEMS

A. Modeling U.S. LNG exports

AEO2023-NEMS and FECM-NEMS have two methods available to calculate LNG export capacity: endogenous and exogenous. There is a switch in the input files that can be toggled between the two methods before executing a run. *S1* uses the EIA AEO2023 reference case, which calculates LNG export capacity endogenously; *S2* through *S6* are initialized with exogenous export capacity, which use exogenous LNG export values from the GCAM model for each scenario. Both AEO2023-NEMS and FECM-NEMS follow a similar process with only minor differences in a small number of input values. In most cases (including all cases discussed in this report) LNG exports will equal LNG export capacity because the cost to construct capacity is so high that capacity will rarely be left unused once built. Therefore, the following description can be treated as an explanation for how AEO2023-NEMS and FECM-NEMS calculate LNG Export volumes.

The algorithm for calculating LNG export capacity endogenously has two steps. In the first step, AEO2023-NEMS considers LNG exports from existing or planned LNG export facilities. Beginning with Cheniere's Sabine Pass facility, which started exporting LNG in 2016, AEO2023-NEMS runs through a list of export facilities specified in an input file. This list is updated with each version of the AEO; AEO2023-NEMS includes existing and planned facilities expected to start or expand production by the end of 2025. For each facility, AEO2023-NEMS slowly increases production over the first few months to represent an export facility ramping up to full capacity.

The second step in the endogenous algorithm involves a prediction of future LNG exports. AEO2023-NEMS uses a set of exogenous values in an input file to specify how much demand Europe and Asia will have for LNG imports, as well as how much supply of non-U.S. LNG will exist on the market. Then, considering the volume of U.S. LNG exports at a given model year, AEO2023-NEMS calculates how the ratio of supply and demand changes over time. This ratio, together with the world oil price, is used to calculate the price at which international customers will purchase U.S. LNG. The purchase price algorithm is constructed in such a way that rises in the oil price, decreases or slowdowns in future LNG supply, or increases in future LNG demand will all increase the purchase price of LNG, and vice-versa. The influence that each factor has on LNG purchase price is controlled by several input parameters.

In addition to a purchase price, AEO2023-NEMS calculates the price at which U.S. LNG could be sold for. This "sale price" combines the natural gas Henry Hub price with various costs that represent the stages of preparing pipeline gas for LNG transport (including liquefaction, fuel consumption, shipping, and regasification). AEO2023-NEMS then compares the sale price to purchase prices at different destinations and determines a discounted net present value (NPV) of new LNG construction over the subsequent 20 years. Depending on the NPV, AEO2023-NEMS will decide to increase LNG export capacity by 0 to 600 Bcf/d. The increase in capacity takes effect after a four year "construction" period and brief "phase-in" period.

The algorithm in AEO2023-NEMS to calculate LNG export capacity exogenously is far simpler. A table in an input file lists LNG export capacity by year; these values are used by AEO2023-NEMS to set LNG exports for that year. In *S2* through *S6*, various parameters, including LNG export volumes, are calculated by the GCAM model. The LNG export volumes are converted to the correct input format and adopted by AEO2023-NEMS as the exogenous LNG export capacity.

B. Additional detail on U.S. natural gas markets

1. Regional natural gas production

Figure B-1 and Figure B-2 plot onshore natural gas production by region for the first five scenarios and the net-zero scenarios, respectively, in 2025 and 2050. Offshore natural gas production comprises a small portion of the total (<4 % in all scenarios and years) and is omitted from these figures.

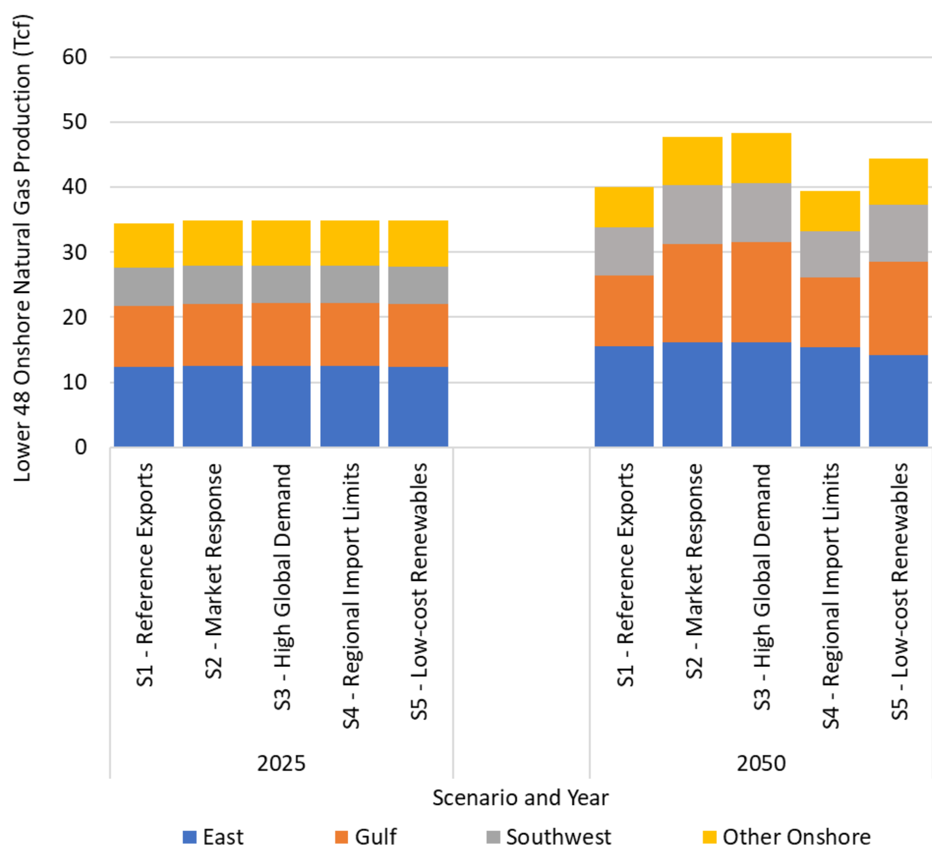


Figure B-1. U.S. Regional Natural gas production, S1 through S5

Natural gas production experienced an upward trend across all scenarios by 2050, equaling or exceeding 39 Tcf. *S3* exhibited the highest production level at 48 Tcf, influenced by the global demand for natural gas. Expansion is primarily characterized by a significant increase in production in the Gulf region, subsequently followed by the Southwest and the East. Conversely, scenario *S4* sees the lowest natural gas production at 39 Tcf with least production growth in the Gulf region.

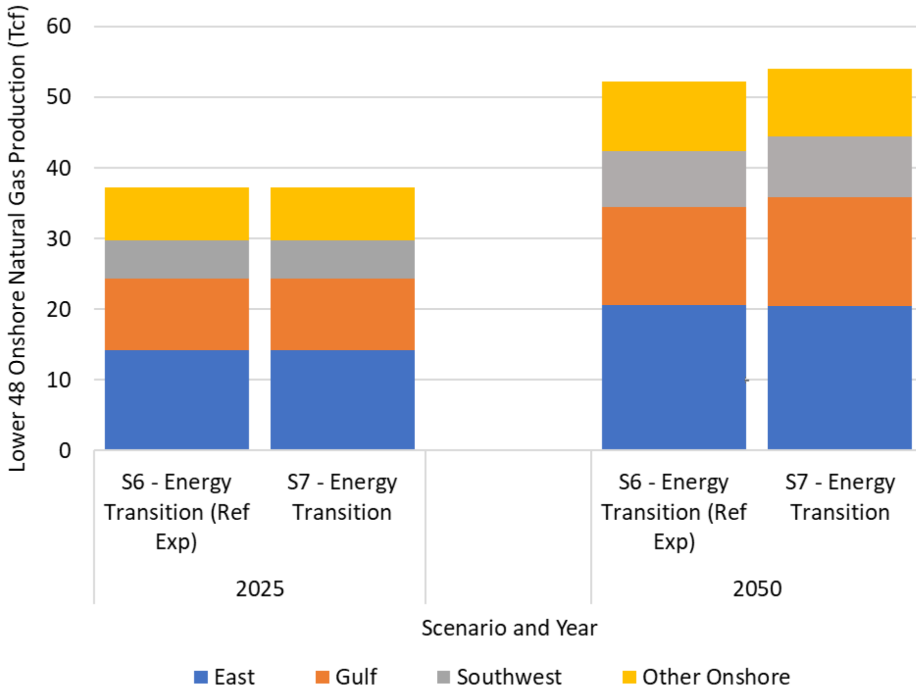


Figure B-2. U.S. regional natural gas production in S6 and S7

Onshore natural gas production grows significantly from 2025 to 2050 for both net-zero scenarios, rising from 37 Tcf in 2025 to 52 Tcf in *S6* and 54 Tcf in *S7*, respectively, by 2050. The large growth in natural gas production is primarily due to demand from DAC facilities, with only a small increase associated with elevated LNG exports in the *S7* scenario. Natural gas production rises in all regions, with the largest absolute increases coming from the East (6.4 Tcf in *S6* and 6.2 Tcf in *S7*) and Gulf (3.8 Tcf in *S6* and 5.3 Tcf in *S7*) regions and the largest increase by percentage coming from the Southwest (47% in *S6* and 58% in *S7*).

2. Natural gas consumption by economic sector

Figure B-3 plots natural gas consumption for electric power, industry, residential use, commercial use, and transportation over time for *S1* through *S5*.

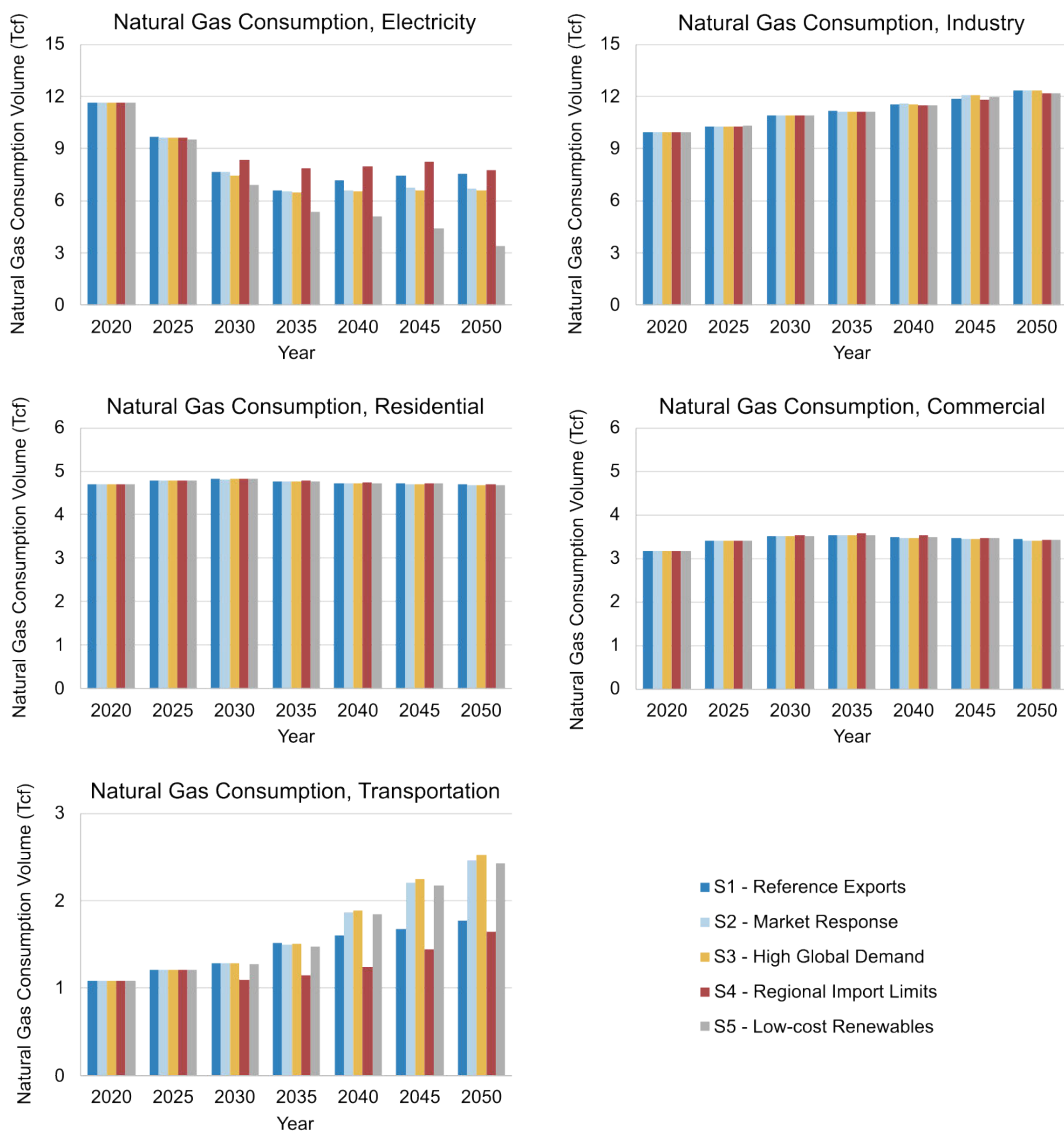


Figure B-3. U.S. natural gas consumption by sector, S1 through S5

Natural gas consumed for electricity was inversely correlated with LNG exports and natural gas prices for *S1*-*S4*. From a starting point of 11.6 Tcf in 2020, the first three scenarios drop to similar consumption volumes of 6.5-6.6 Tcf in 2035 before slightly increasing to 7.6 Tcf (*S1*) or plateauing at 6.7 and 6.6 Tcf (*S2* and *S3*, respectively) in 2050. The increased consumption of natural gas for electricity in *S1* can be explained as a response to price reductions caused by plateauing LNG exports, whereas high prices and exports in *S2* and *S3* lead to a flat consumption trend. *S4* – the scenario with the fewest exports and lowest prices through the first half of the model – exhibited the highest consumption for electricity in 2035 of 7.9 Tcf, which rises and falls slightly to a similar level to *S1* in 2050 (7.8 Tcf). *S5* is again an outlier here, reporting consistently lower natural gas consumption that hit a minimum of 3.4 Tcf in 2050. This trend is a consequence of its low renewable costs reducing the demand for natural gas in the electric sector.

Unlike for electricity, there was no significant difference between scenarios in the rate of natural gas consumption in the industrial, residential, or commercial sectors. Industrial natural gas consumption rises from 9.9 Tcf in 2020 to 12.2-12.4 Tcf in 2050 across the five scenarios; residential consumption remains relatively unchanged at 4.7 Tcf from 2020 to 2050 with some small variations; and commercial consumption rises and falls slightly from 3.2 Tcf in 2020 to 3.4 Tcf in 2050.

Natural gas consumed for transportation has a different response to changes in LNG exports, compared with the other consumptions sectors. The transportation category is dominated by pipeline fuel: natural gas consumed to power infrastructure underlying the natural gas supply chain, which includes LNG exports. Increases in natural gas consumption for transportation therefore correlate strongly with the quantity of LNG exports; *S3* exhibits the highest consumption in the transportation sector by 2050, followed by *S2* and *S5*, *S1*, and finally *S4*.

The sector-by-sector changes across the five scenarios end up cancelling each other out for *S1*-*S4*, leading to nearly identical total natural gas consumption values, as seen in Figure 16 in the main text. Only *S5*, thanks to its low renewable costs, exhibits a lower overall U.S. natural gas consumption trend.

Comparisons of *S1* through *S5* with *S6* and *S7* are complicated because of the many significant changes to the energy economy (going from AEO2023-NEMS to FECM22-NEMS) that occur to satisfy the net-zero criteria. Relative to *S1*, natural gas consumption values decline across most sectors in *S6* and *S7* but are substantially higher in the industry sector (where DAC consumption is categorized). Figure B-4 plots natural gas consumption for the net-zero cases on a sector-by-sector basis.

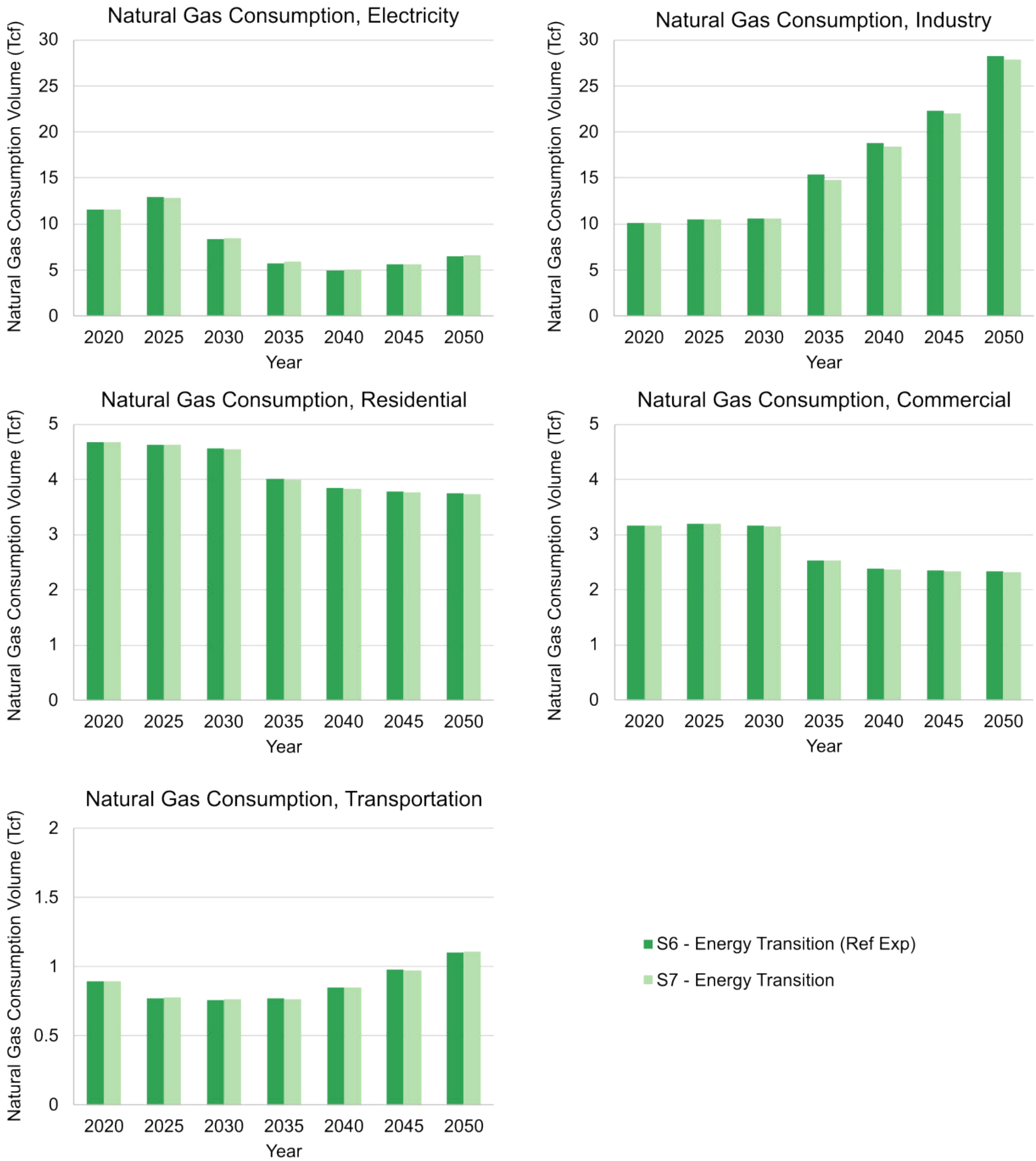


Figure B-4. U.S. natural gas consumption by sector, net-zero scenarios

Differences in historical natural gas consumption and subsequent short-term effects cause a difference in natural gas consumption for electricity in 2020 and 2025 between *S6* and *S7* (from the FECM-NEMS model) and *S1* through *S5* (from the AEO2023-NEMS model). Similar differences in the historical data exist for all sector-specific consumption values. Volumes of natural gas consumed for electricity track closely between the two net-zero cases across most of the modeling years, ranging from 5.7 to 5.9 Tcf in 2035 for *S6* and *S7*, respectively, and rising in later years to 6.5 Tcf and 6.6 Tcf. *S6* reports a lower natural gas consumption value in 2050 than *S1* (7.6 Tcf), but the corresponding result for *S7* is fairly close to *S2* (6.7 Tcf).

Industry-sector natural gas consumption exhibits the largest change between S6 and S7 and *S1* through *S5*, thanks to the strong influence of DAC. Whereas industry consumption of natural gas in *S1* and *S2* both increase from 9.9 Tcf to 12.3 Tcf over the 50 model years, the net-zero scenarios diverge after 2030 and grow rapidly to 28.2 and 27.8 Tcf for *S6* and *S7*, respectively, by 2050. The difference in consumption values is consistent with the natural gas consumption for DAC, which is plotted below in Figure B-5.

Residential- and commercial-sector natural gas consumption follow similar behavior. These values decrease in both net-zero scenarios across the model years from 4.7 to 3.7 Tcf (residential) and from 3.2 to 2.3 Tcf (commercial). By comparison, both *S1* and *S2* have static or slightly increasing trends, with both reporting 4.7 Tcf in 2020 and 2050 for residential consumption and 3.2 to 3.4 Tcf from 2020 to 2050 for commercial consumption.

Transportation is the smallest of the five sectors in terms of natural gas consumption volumes, and calculation differences between AEO2023-NEMS and FECM-NEMS lead to large impacts on the consumption values. As a result, these values are not directly comparable between the three scenarios. *S6* and *S7* have nearly identical volumes of natural gas consumed for the transportation sector, varying from 0.9 Tcf in 2020 to 0.8 Tcf in 2035 and 1.1 Tcf in 2050. By comparison, *S1* and *S2* report consistently higher natural gas consumption for transportation across the model years, ranging from 1.1 Tcf in 2020 to 1.8 and 2.3 Tcf, respectively, in 2050.

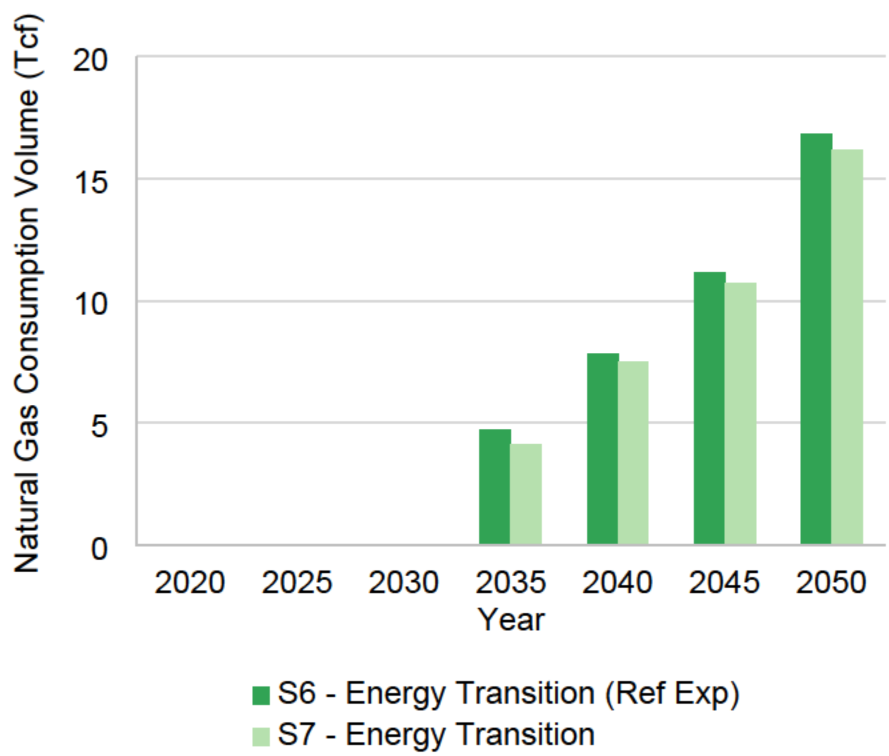


Figure B-5. Natural gas consumed for DAC, net-zero scenarios

DAC is the main technology used by FECM-NEMS to meet the CO_2 cap and by 2050 is responsible for removing 1930 MMT CO_2 per year in *S6* and 1850 MMT CO_2 per year in *S7*. A considerable amount of natural gas is consumed to support these levels of DAC: 16.8 Tcf and 16.2 Tcf in 2050 for *S6* and *S7*, respectively. More detail on CO_2 removal technologies in FECM-NEMS is given in the section below.

In conclusion, even though four out of the five sectors exhibit decreases when comparing natural gas consumption in the net-zero scenarios to *S1* and *S2*, the strong increases in the industrial sector (mainly from increases in DAC) cause overall U.S. natural gas consumption to be significantly higher by 2050 in *S6* and *S7*. There is minimal difference between the *S6* and *S7* results, suggesting that the differences in LNG exports between the net-zero scenarios play a limited role in altering natural gas consumptions trends.

C. CO_2 removal technologies in FECM-NEMS

CO_2 removals in FECM-NEMS are driven by three technologies: production of hydrogen with sequestered biomass, BECCS, and DAC. Figure B-6 plots CO_2 removals for each technology and scenario by year.

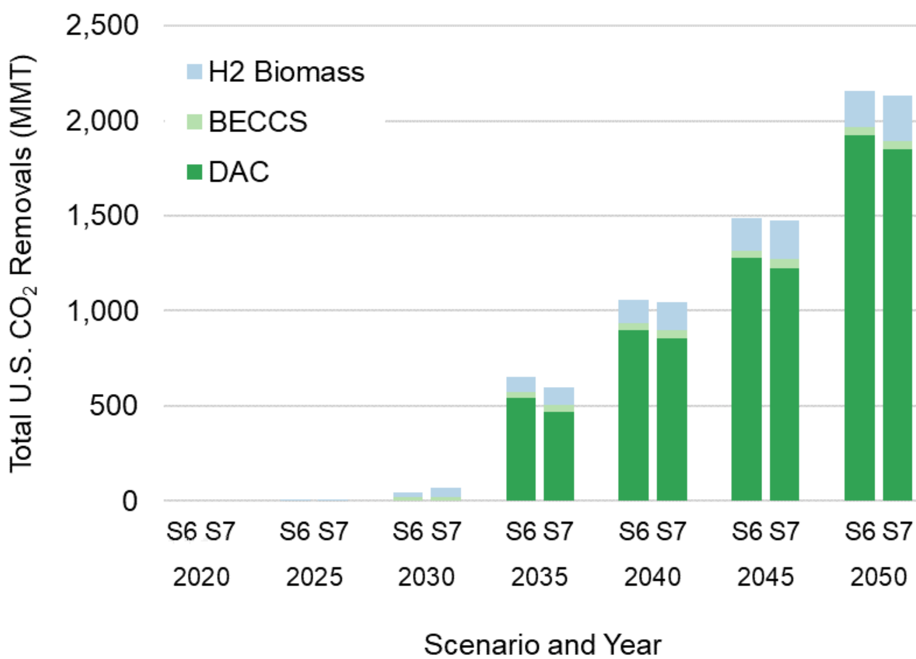


Figure B-6. U.S. CO_2 emissions and removals, net-zero scenarios

DAC is most widely used in both net-zero scenarios and scales up rapidly after 2030 to account for 1930 MMT CO_2 removed in *S6* and 1850 MMT CO_2 removed in *S7* (89% and 87% of total removals, respectively) by 2050. H2 biomass and BECCS see significantly less adoption by 2050 in both scenarios; the former reaches 200 (9% of total) and 240 (11% of total) MMT CO_2 removed in *S6* and *S7*, respectively, whereas the later reaches approximately 40 MMT CO_2 removed in both scenarios (2% of total removals).

FECM-NEMS relies on two sets of DAC technology assumptions: "grid", and "NG only," derived from the literature using updated cost and performance data from FECM.[24] Both use natural gas to power the capture process; DAC-grid offsets some of the natural gas demand by using electricity as well as lists the specific technical assumptions underlying the two DAC options.

Table B-1. DAC technology assumptions in FECM-NEMS

	Capex, \$/ton-year	CRF	Capex, \$/ton	Opex, \$/ton	Electricity demand, kwhr/ton	Natural gas demand, MMBtu/ton
Grid	\$1,300	7.1%	\$112	\$71	450	8.75
NG Only	\$1,500	7.1%	\$129	\$83.6	0	9.27

The effect of DAC on natural gas markets in *S6* and *S7* can be seen in the rapid growth of total natural gas consumption and subsequent rise in natural gas prices (Figure 18) in the main text. By 2050, natural gas consumption equals 16.8 Tcf and 16.2 Tcf for *S6*, and *S7*, respectively, reaching natural gas prices of \$5.90 2022/Mcf and \$5.77 2022/Mcf.

FECM-NEMS models the deployment of carbon removal technologies by determining a CO_2 price that represents the market equilibrium cost to capture and abate CO_2 emissions. FECM-NEMS adjusts the CO_2 price in accordance with the imposed carbon cap to ensure that the correct number of CO_2 emissions are abated each year.

[24] National Academies of Sciences, Engineering, and Medicine. (2019). Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. Washington, DC: The National Academies Press. https://doi.org/10.17226/25259.

Appendix C: Supporting LCA Analysis

A. NEMS and NETL LCA model comparison

The NEMS modeling done in this project focused on domestic changes that would be expected to occur in the seven scenarios modeled. NETL reviewed the NEMS data to evaluate if the regional production mix of natural gas would be expected to change over time. 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 adjustments would be recommended to the assumed GHG intensity for U.S. natural gas in the results.

For *S1* - *S7*, NEMS modeled data of dry natural gas production of "Production by OGSM District" was mapped to a state and then to an NETL natural gas model region as shown in Table C- 1. Note that several "states" are offshore regions.

Table C- 1. Matching NEMS (OGMP States) to NETL states and subsequently regions

Production by OGSM District	State	Region
Alabama, North	Alabama	Southeast
Alabama, South	Alabama	Southeast
Arizona	Arizona	Southwest
Arkansas	Arkansas	Southeast
California	California	Pacific
Colorado	Colorado	Rocky Mountain
Connecticut	Connecticut	Northeast
Delaware	Delaware	Northeast
Washington, D.C.	Washington	Pacific
Florida	Florida	Southeast
Georgia	Georgia	Southeast
Idaho	Idaho	Rocky Mountain
Illinois	Illinois	Midwest
Indiana	Indiana	Midwest
Iowa	Iowa	Midwest
Kansas	Kansas	Midwest
Kentucky	Kentucky	Southeast
Louisiana, North	Louisiana	Southeast
Louisiana, South	Louisiana	Southeast
Maryland	Maryland	Northeast
Massachusetts	Massachusetts	Northeast
Michigan	Michigan	Midwest
Minnesota	Minnesota	Midwest
Mississippi, North	Mississippi	Southeast
Mississippi, South	Mississippi	Southeast
Missouri	Missouri	Midwest

Production by OGSM District	State	Region
Montana	Montana	Rocky Mountain
Nebraska	Nebraska	Midwest
Nevada	Nevada	Rocky Mountain
New Hampshire	New York	Northeast
New Jersey	New Jersey	Northeast
New Mexico, East	New Mexico	Southwest
New Mexico, West	New Mexico	Southwest
New York	New York	Northeast
North Carolina	North Carolina	Southeast
North Dakota	North Dakota	Midwest
Ohio	Ohio	Midwest
Oklahoma	Oklahoma	Southwest
Oregon	Oregon	Pacific
Pennsylvania	Pennsylvania	Northeast
Rhode Island	Rhode Island	Northeast
South Carolina	South Carolina	Southeast
South Dakota	South Dakota	Midwest
Tennessee	Tennessee	Southeast
Texas RRC 1	Texas	Southwest
Texas RRC 2	Texas	Southwest
Texas RRC 3	Texas	Southwest
Texas RRC 4	Texas	Southwest
Texas RRC 5	Texas	Southwest
Texas RRC 6	Texas	Southwest
Texas RRC 7B	Texas	Southwest
Texas RRC 7C	Texas	Southwest
Texas RRC 8	Texas	Southwest
Texas RRC 8A	Texas	Southwest
Texas RRC 9	Texas	Southwest
Texas RRC 10	Texas	Southwest
Utah	Utah	Rocky Mountain
Virginia	Virginia	Northeast
Washington	Washington	Pacific
West Virginia	West Virginia	Northeast
Wisconsin	Wisconsin	Midwest
Wyoming	Wyoming	Rocky Mountain
North Atlantic State Offshore	North Carolina	Southeast
South Atlantic State Offshore	South Carolina	Southeast
Alabama State Offshore	Alabama	Southeast
Louisiana State Offshore	Louisiana	Southeast

Production by OGSM District	State	Region
Texas State Offshore	Texas	Southwest
California State Offshore	California	Pacific
North Atlantic Federal Offshore	North Carolina	Southeast
Mid Atlantic Federal Offshore	Federal Offshore - GoM	Southeast
South Atlantic Federal Offshore	South Carolina	Southeast
Eastern GOM Federal Offshore	Federal Offshore - GoM	Southeast
Central GOM Federal Offshore	Federal Offshore - GoM	Southeast
Western GOM Federal Offshore	Federal Offshore - GoM	Southeast
California Federal Offshore	California	Pacific
Northern Pacific Federal Offshore	Federal Offshore - GoM	Southeast
Alaska Federal Offshore	Federal Offshore - GoM	Southeast

This classification enables the aggregation of dry production data (excluding extraction losses) by region for each respective year, as summarized with every 10 years of data in Table C-2.

Table C-2 Regional dry production (trillion cubic feet) between 2020 and 2050, S1

Region	2020	2030	2040	2050
Midwest	3.26778	2.82406	2.40796	2.094116
Northeast	9.540964	11.14082	13.03394	14.08478
Pacific	0.163061	0.285247	0.296763	0.280681
Rocky Mountain	3.328845	2.899944	2.796355	2.687115
Southeast	4.587738	6.084166	6.64734	5.720366
Southwest	12.2792	13.3737	15.27886	16.65195

From this aggregated data, the production ratio is calculated by dividing the region-specific production by the total U.S. production for each year and summarized in Table C-3.

Table C-3 Regional dry production ratio, S1

Region	2020	2030	2040	2041	2050
Midwest	9.85	7.71	5.95	5.79	5.04
Northeast	28.77	30.43	32.21	32.75	33.92
Pacific	0.49	0.78	0.73	0.71	0.68
Rocky Mountain	10.04	7.92	6.91	6.94	6.47
Southeast	13.83	16.62	16.43	15.94	13.78
Southwest	37.02	36.53	37.76	37.87	40.11

Figure C-1 shows the percent of natural gas dry production for each region of *S1* as compared to total production in each year between 2020 and 2050. The same process was done for the other scenarios.

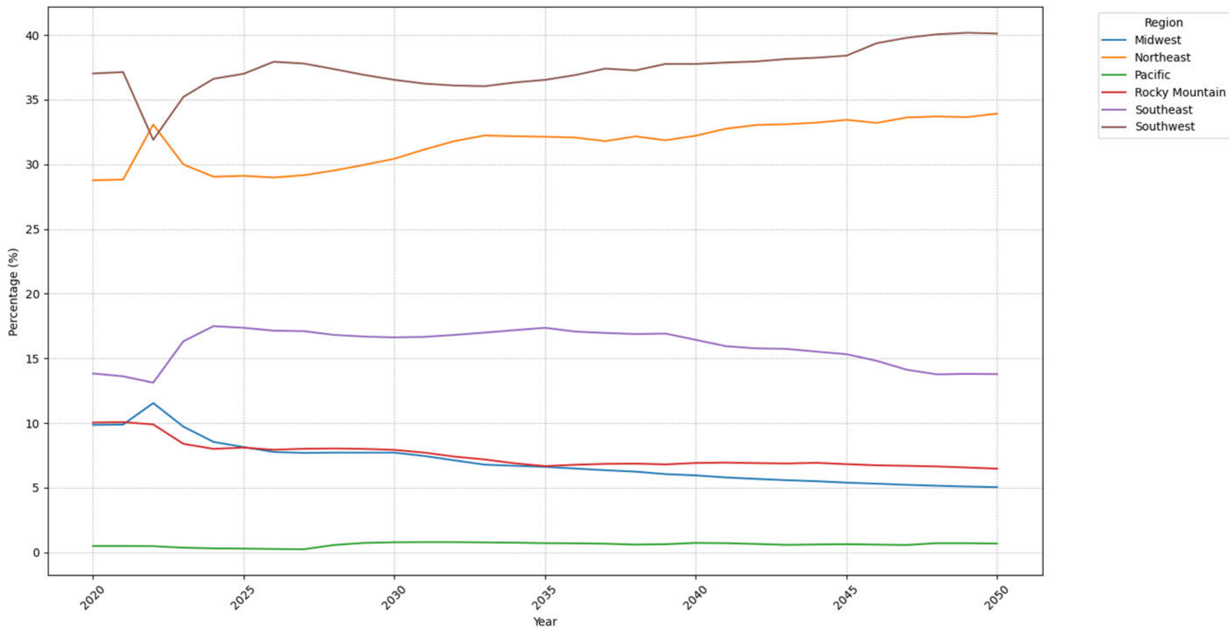


Figure C-1. Dry NG production percentage time-series for each region

This percentage can be multiplied with the 2020 GHG intensity values for each region from the NETL Natural Gas report[16] (shown in Table C-4) to estimate future GHG intensity results, as described in this mathematical representation:

$$GHG_{Midwest,2021} = GHG_{Midwest,2020} \times \; dry\,production\,ratio_{Midwest,\,2021}$$

and finding the weighted US average GHG intensity across regions.

Table C-4. Regional GHG Intensities (gCO_2e/MJ) from 2020 NETL Natural Gas Report

Region	GHG (gCO_2e/MJ)
Midwest	8.44
Northeast	6.23
Pacific	11.3
Rocky Mountain	10.01
Southeast	9.02
Southwest	8.80

Overall, Figure C-2 suggests that the NEMS-modeled changes in domestic production by region across the scenarios are not expected to have a significant effect on the GHG intensity of domestic production (given the 2020 data on GHG intensity by region) if only the trend in “dry production” (based on delivery shares) is considered.

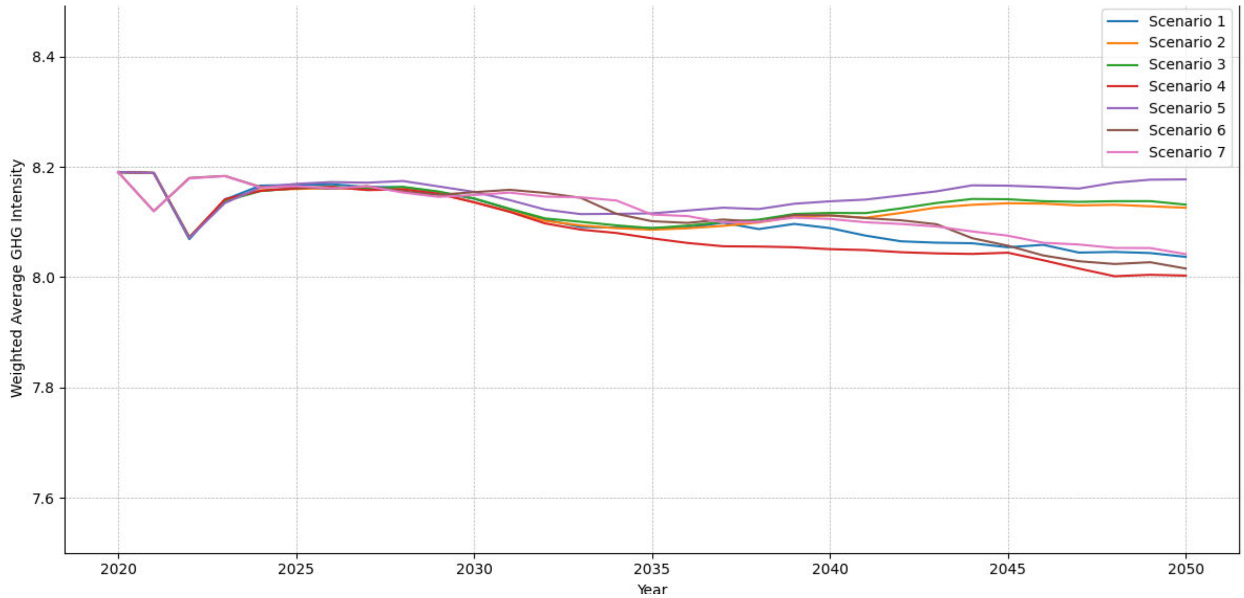


Figure C-2. Estimated U.S. Average GHG Intensity (g CO_2e/MJ) (S1 through S7), Production through Transmission (2020 - 2050)

B. 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 factors is relevant to this analysis (i.e., with a focus on the natural gas sector).

Results provided by PNNL for the various Scenarios (1-7) and years modeled were provided as described in Table C-5, and were processed accordingly.

Table C-5. 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.
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 and 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.

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 CO_2 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 CO_2 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., CH4, N2O, HFC125, 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).

C. GCAM and NETL emissions intensity comparison

As noted in the main report, only three sectors of the GCAM model have information relevant to the upstream natural gas supply chain. The GCAM *gas pipeline* and *natural gas* sectors are assumed to wholly incorporate natural gas-relevant emissions, and so total emissions are 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. GCAM incorporates a variety of data sources to represent activity in this sector. Relevant to natural gas activities 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, as in Table C-6. The provided data (not shown) details what percent of energy use in the sector was from the IEA energy flows (e.g., 25% of total sectoral energy use in a region from Extraction and Gathering and Boosting). As 99.5% of GHG emissions in the *other industrial energy use* sector are CO_2, only the IEA data source was used and only CO_2 data for that sector was adjusted.

Table C-6. LCA Stage Cross-Mapping

NETL 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

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 are excluded from the analysis, consistent with the focus on upstream natural gas effects.

The emissions intensity cells in Table C-7 show the underlying equation used to generate values on an AR6-100 basis, where the numerator is the total emissions from the GCAM model for the USA region for Scenario *S1* for the year 2020 for each of the three greenhouse gases (if available), normalized by the total production of U.S. natural gas and oil from the GCAM model in 2020 (32.46 EJ and 22.46 EJ, respectively). 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 C-7show comparisons to those of the NETL model.

As implemented, this adjustment factor of 0.96 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. The existing methane mitigation trend in the GCAM emissions data for the *natural gas* sector was preserved by using this adjustment method.

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 in emissions associated with only natural gas activity 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 (i.e., it does not lead to a 4% reduction in emissions intensity for the other industrial energy use sector), it avoids the outcome where that sector's emissions are reduced for all of the other activities.

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).

Table C-7. GCAM Emissions Intensities for Sectors (S1, 2020, USA region, AR6-100 basis)

			Estimated GCAM Emissions Intensity (LHV) (Tg CO_2e / EJ, g CO_2e / MJ) [IPCC AR6 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.	38.0/32.5 = 1.17	-	-
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.	-	139.0/32.5 = 4.28	.015/32.5 = 4.5 E-4
other industrial energy use (technology = gas or gas cogen)[a]	**For 2015**, Extraction, Gathering & Boosting	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	92.9/32.5 = 2.86	-	-
other industrial energy use (technology = refined liquids and refined liquids cogen)[a]			11/(32.5+22.5) = 0.2	-	-

other industrial energy use (electricity)[a]		natural gas and crude oil products on an energy (EJ) produced basis from GCAM output data.	-	-	-
Total GCAM by gas (LHV)			= 1.17 + 2.86 + .2 = 4.23	4.28	4.5 E-4
Total GCAM (LHV)			8.52		
Subtotal from NETL Model, Processing through Transmission boundary – LHV basis			8.18		
Adjustment factor (LHV)			8.18/8.52 = 0.96		

Using the same detailed approach, Tables C-8 through C-10 more succinctly summarize the provided GCAM values and adjustments identified for the IPCC AR values.

Table C-8. GCAM Emissions Intensities for Sectors (S1, 2020, USA region, AR6-20 basis)

	Estimated GCAM Emissions Intensity ($Tg\ CO_2e$ / EJ, $g\ CO_2e$ / MJ) [IPCC AR6 20 yr]		
GCAM Sector	CO_2	CH_4	N_2O
gas pipeline	1.17	-	-
natural gas	-	11.86	4.5 E-4
other industrial energy use (technology = gas or gas cogen)	2.86	-	-
other industrial energy use (technology = refined liquids and refined liquids cogen)	0.2	-	-
Total GCAM by gas (LHV)	= 1.17 + 2.86 + .2 = 4.23	11.86	4.5 E-4
Total GCAM (LHV)	16.1		
NETL (LHV basis)	13.8		
Adjustment Factor (LHV)	0.86		

Table C-9. GCAM Emissions Intensities for Sectors (S1, 2020, USA region, AR5-100 basis)

	Estimated GCAM Emissions Intensity ($Tg\ CO_2e$ / EJ, $g\ CO_2e$ / MJ) [IPCC AR5 100 yr]		
GCAM Sector	**CO_2**	**CH_4**	**N_2O**
gas pipeline	1.17	-	-
natural gas	-	5.18	4.9 E-4
other industrial energy use (technology = gas or gas cogen)	2.86	-	-
other industrial energy use (technology = refined liquids and refined liquids cogen)	0.2	-	-
Total GCAM by gas (LHV)	= 1.17 + 2.86 + .2 = 4.23	5.18	4.9 E-4
Total GCAM (LHV)	9.41		
NETL (LHV basis)	8.84		
Adjustment Factor (LHV)	0.94		

Table C-10. GCAM Emissions Intensities for Sectors (S1, 2020, USA region, AR5-20 basis)

	Estimated GCAM Emissions Intensity ($Tg\ CO_2e$ / EJ, $g\ CO_2e$ / MJ) [IPCC AR5 20 yr]		
GCAM Sector	**CO_2**	**CH_4**	**N_2O**
gas pipeline	1.17	-	-
natural gas	-	12.36	4.4 E-4
other industrial energy use (technology = gas or gas cogen)	2.86	-	-
other industrial energy use (technology = refined liquids and refined liquids cogen)	0.2	-	-
Total GCAM by gas (LHV)	= 1.17 + 2.86 + .2 = 4.23	12.36	4.4 E-4
Total GCAM (LHV)	16.6		
NETL (LHV basis)	14.2		
Adjustment Factor (LHV)	0.86		

Table C-11 shows the GWP of key greenhouse gases which were used in conjunction with the emissions factors to derive the overall life-cycle greenhouse gas intensity.

Table C-11. GWP Values used in this analysis

Greenhouse Gas	AR5-100 (with ccf)	AR5-20 (with ccf)	AR6-100	AR6-20
CH4 (fossil)	36	86	29.8	82.5
CH4 (non-fossil)	34	84	27.2	80.8
N2O (fossil)	298	268	273	273
N2O (non-fossil)	298	268	273	273
HFC125	3691	6207	3740	6740
HFC134a	1549	3789	1530	4140
HFC143a	5508	7064	5810	7840
HFC23	13856	11005	14600	12400
HFC32	817	2502	771	2690
SF6	26087	17783	24300	18200
HFC245fa	1032	2992	962	3170
HFC365mfc	966	2724	914	2920
C2F6	12340	8344	12400	8940
CF4	7349	4954	7380	5300
HFC43	1952	4403	1600	3960
HFC152a	167	524	164	591
HFC227ea	3860	3860	3600	5850
HFC236fa	8998	9810	8690	7450

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.

1. Market Adjustment Factors for other IPCC GWP Values

Table C-12 shows all MAF results for Scenario 2.

Table C-12. NETL-adjusted MAF results for S2

Results (g CO_2e/ MJ, LHV basis)					
MAF Case	**AR5, 100 with ccf**	**AR5, 20 with ccf**	**AR6-100**	**AR6-20**	**Scenario Difference**
***S2* vs. *S1* - unadjusted**	-5.85	-9.17	-5.34	-8.86	Adds economic solution for LNG exports.
***S2* vs. *S1* - adjusted**	-5.86	-9.12	-5.35	-8.74	

Table C-13 shows all MAF results for *Scenario 7*.

Table C-13 NETL-adjusted MAF results for S7

Results (g CO_2e/ MJ, LHV basis)					
MAF Case	**AR5, 100 with ccf**	**AR5, 20**	**AR6-100**	**AR6-20**	**Scenario Difference**
***S7* vs. *S6* - unadjusted**	-3.54	-7.54	-3.01	-7.25	S6 1.5°C pathway, economic solution for LNG exports
***S7* vs. *S6* - adjusted**	-3.44	-7.26	-2.95	-6.61	

Table C-14 shows the underlying annual CO_2e emissions and US LNG export volumes used in the MAF calculations above for the AR6-100 case (with adjustments).

Table C-14. Annual Export Volumes of US LNG and Adjusted Global CO_2 Emissions (AR6-100 basis)

Scenario	Year	US Export LNG (EJ)	Global CO_2e Emissions (Tg)
S1	2015	0.018	49656.4
S1	2016	0.538	50410.5
S1	2017	1.058	51164.6
S1	2018	1.578	51918.8
S1	2019	2.097	52672.9
S1	2020	2.617	53427.0
S1	2021	3.086	52816.1
S1	2022	3.555	52205.2
S1	2023	4.023	51594.3
S1	2024	4.492	50983.3
S1	2025	4.961	50372.4
S1	2026	5.372	50692.9
S1	2027	5.782	51013.5
S1	2028	6.193	51334.0
S1	2029	6.603	51654.5
S1	2030	7.014	51975.0
S1	2031	7.544	51974.5
S1	2032	8.074	51973.9
S1	2033	8.605	51973.4
S1	2034	9.135	51972.9
S1	2035	9.665	51972.3
S1	2036	9.766	51862.9
S1	2037	9.867	51753.5
S1	2038	9.968	51644.2
S1	2039	10.069	51534.8
S1	2040	10.170	51425.4
S1	2041	10.170	51339.6

Scenario	Year	US Export LNG (EJ)	Global CO_2e Emissions (Tg)
S1	2042	10.170	51253.8
S1	2043	10.170	51168.0
S1	2044	10.170	51082.2
S1	2045	10.170	50996.5
S1	2046	10.170	50853.8
S1	2047	10.170	50711.2
S1	2048	10.170	50568.6
S1	2049	10.170	50426.0
S1	2050	10.170	50283.4
S2	2015	0.018	49656.4
S2	2016	0.538	50410.5
S2	2017	1.058	51164.6
S2	2018	1.578	51918.8
S2	2019	2.097	52672.9
S2	2020	2.617	53427.0
S2	2021	3.086	52816.1
S2	2022	3.555	52205.2
S2	2023	4.023	51594.3
S2	2024	4.492	50983.3
S2	2025	4.961	50372.4
S2	2026	5.372	50692.9
S2	2027	5.782	51013.5
S2	2028	6.193	51334.0
S2	2029	6.603	51654.5
S2	2030	7.014	51975.0
S2	2031	7.462	51975.0
S2	2032	7.910	51975.0
S2	2033	8.358	51975.0
S2	2034	8.806	51975.0
S2	2035	9.254	51975.0
S2	2036	9.996	51862.2
S2	2037	10.738	51749.4
S2	2038	11.481	51636.5
S2	2039	12.223	51523.7
S2	2040	12.965	51410.9
S2	2041	13.561	51323.2
S2	2042	14.157	51235.6
S2	2043	14.753	51147.9
S2	2044	15.350	51060.3
S2	2045	15.946	50972.7

Scenario	Year	US Export LNG (EJ)	Global CO_2e Emissions (Tg)
S2	2046	16.271	50824.2
S2	2047	16.597	50675.8
S2	2048	16.922	50527.3
S2	2049	17.248	50378.9
S2	2050	17.573	50230.4
S3	2015	0.018	49656.4
S3	2016	0.538	50440.8
S3	2017	1.058	51225.3
S3	2018	1.578	52009.7
S3	2019	2.097	52794.2
S3	2020	2.617	53578.6
S3	2021	3.086	52949.2
S3	2022	3.555	52319.7
S3	2023	4.023	51690.2
S3	2024	4.492	51060.8
S3	2025	4.961	50431.3
S3	2026	5.371	50776.7
S3	2027	5.781	51122.1
S3	2028	6.191	51467.5
S3	2029	6.601	51812.9
S3	2030	7.011	52158.3
S3	2031	7.486	52193.5
S3	2032	7.961	52228.6
S3	2033	8.435	52263.8
S3	2034	8.910	52298.9
S3	2035	9.385	52334.1
S3	2036	10.148	52260.8
S3	2037	10.910	52187.4
S3	2038	11.673	52114.0
S3	2039	12.435	52040.7
S3	2040	13.198	51967.3
S3	2041	13.826	51922.6
S3	2042	14.453	51877.9
S3	2043	15.081	51833.2
S3	2044	15.709	51788.5
S3	2045	16.337	51743.8
S3	2046	16.697	51646.1
S3	2047	17.057	51548.4
S3	2048	17.417	51450.7
S3	2049	17.777	51353.0

Scenario	Year	US Export LNG (EJ)	Global CO_2e Emissions (Tg)
S3	2050	18.136	51255.3
S4	2015	0.018	49656.4
S4	2016	0.538	50410.5
S4	2017	1.058	51164.6
S4	2018	1.578	51918.8
S4	2019	2.097	52672.9
S4	2020	2.617	53427.0
S4	2021	3.086	52816.7
S4	2022	3.555	52206.5
S4	2023	4.023	51596.2
S4	2024	4.492	50985.9
S4	2025	4.961	50375.7
S4	2026	4.873	50698.7
S4	2027	4.784	51021.8
S4	2028	4.696	51344.8
S4	2029	4.607	51667.8
S4	2030	4.519	51990.9
S4	2031	4.602	51989.4
S4	2032	4.685	51987.8
S4	2033	4.768	51986.3
S4	2034	4.851	51984.8
S4	2035	4.934	51983.2
S4	2036	5.080	51874.4
S4	2037	5.226	51765.6
S4	2038	5.371	51656.7
S4	2039	5.517	51547.9
S4	2040	5.662	51439.1
S4	2041	6.004	51348.5
S4	2042	6.345	51257.9
S4	2043	6.687	51167.4
S4	2044	7.028	51076.8
S4	2045	7.370	50986.3
S4	2046	7.612	50840.2
S4	2047	7.854	50694.2
S4	2048	8.096	50548.1
S4	2049	8.338	50402.1
S4	2050	8.580	50256.1
S5	2015	0.018	49656.4
S5	2016	0.538	50409.0
S5	2017	1.058	51161.6

Scenario	Year	US Export LNG (EJ)	Global CO_2e Emissions (Tg)
S5	2018	1.578	51914.1
S5	2019	2.097	52666.7
S5	2020	2.617	53419.3
S5	2021	3.086	52803.6
S5	2022	3.555	52187.8
S5	2023	4.023	51572.1
S5	2024	4.492	50956.3
S5	2025	4.961	50340.6
S5	2026	5.372	50661.1
S5	2027	5.782	50981.7
S5	2028	6.193	51302.2
S5	2029	6.604	51622.8
S5	2030	7.015	51943.3
S5	2031	7.467	51939.6
S5	2032	7.920	51935.9
S5	2033	8.373	51932.2
S5	2034	8.826	51928.5
S5	2035	9.279	51924.8
S5	2036	10.020	51808.5
S5	2037	10.760	51692.1
S5	2038	11.500	51575.8
S5	2039	12.241	51459.5
S5	2040	12.981	51343.2
S5	2041	13.561	51248.0
S5	2042	14.141	51152.9
S5	2043	14.722	51057.7
S5	2044	15.302	50962.5
S5	2045	15.882	50867.3
S5	2046	16.216	50710.9
S5	2047	16.550	50554.5
S5	2048	16.884	50398.1
S5	2049	17.219	50241.7
S5	2050	17.553	50085.3
S6	2015	0.018	49656.4
S6	2016	0.538	50410.9
S6	2017	1.058	51165.4
S6	2018	1.578	51920.0
S6	2019	2.097	52674.5
S6	2020	2.617	53429.0
S6	2021	3.086	52542.1

Scenario	Year	US Export LNG (EJ)	Global CO_2e Emissions (Tg)
S6	2022	3.555	51655.2
S6	2023	4.023	50768.2
S6	2024	4.492	49881.3
S6	2025	4.961	48994.3
S6	2026	5.067	49084.3
S6	2027	5.173	49174.3
S6	2028	5.278	49264.3
S6	2029	5.384	49354.3
S6	2030	5.490	49444.3
S6	2031	5.782	48082.7
S6	2032	6.075	46721.2
S6	2033	6.367	45359.6
S6	2034	6.659	43998.0
S6	2035	6.951	42636.4
S6	2036	7.481	41287.6
S6	2037	8.010	39938.9
S6	2038	8.539	38590.1
S6	2039	9.068	37241.3
S6	2040	9.597	35892.5
S6	2041	9.712	34455.5
S6	2042	9.827	33018.4
S6	2043	9.941	31581.4
S6	2044	10.056	30144.4
S6	2045	10.170	28707.3
S6	2046	10.170	27334.6
S6	2047	10.170	25961.9
S6	2048	10.170	24589.1
S6	2049	10.170	23216.4
S6	2050	10.170	21843.7
S7	2015	0.018	49656.4
S7	2016	0.538	50410.9
S7	2017	1.058	51165.4
S7	2018	1.578	51920.0
S7	2019	2.097	52674.5
S7	2020	2.617	53429.0
S7	2021	3.086	52542.1
S7	2022	3.555	51655.2
S7	2023	4.023	50768.2
S7	2024	4.492	49881.3
S7	2025	4.961	48994.3

Scenario	Year	US Export LNG (EJ)	Global CO_2e Emissions (Tg)
S7	2026	5.067	49084.3
S7	2027	5.173	49174.3
S7	2028	5.278	49264.3
S7	2029	5.384	49354.3
S7	2030	5.490	49444.3
S7	2031	5.782	48082.7
S7	2032	6.075	46721.2
S7	2033	6.367	45359.6
S7	2034	6.659	43998.0
S7	2035	6.951	42636.4
S7	2036	7.481	41287.6
S7	2037	8.010	39938.9
S7	2038	8.539	38590.1
S7	2039	9.068	37241.3
S7	2040	9.598	35892.5
S7	2041	10.012	34454.7
S7	2042	10.427	33016.8
S7	2043	10.842	31578.9
S7	2044	11.257	30141.1
S7	2045	11.671	28703.2
S7	2046	11.836	27329.8
S7	2047	12.001	25956.4
S7	2048	12.166	24583.1
S7	2049	12.331	23209.7
S7	2050	12.496	21836.3