

STRATUS CONSULTING

Greenhouse Gas Emissions from Fossil Energy Extracted from Federal Lands and Waters: An Update

Final

Prepared for:

The Wilderness Society
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1. Introduction

In April 2011, the Council on Environmental Quality (CEQ) released the *Greenhouse Gas Emissions Inventory for the Federal Government: 2010 Data* (CEQ, 2011). This report presented the total estimated greenhouse gas (GHG) emissions associated with federal government agency operations, including emissions from building electricity and water consumption, employee travel, and numerous other activities. However, the inventory did not account for emissions associated with a range of activities subject to federal agency oversight but conducted by private entities. Such activities include exploration, production, and development of fossil fuel resources on federal lands[1] by private sector leaseholders. Accounting for these activities could increase the federal government's total emissions of GHGs substantially.

In 2012, Stratus Consulting produced a report on behalf of The Wilderness Society entitled *Greenhouse Gas Emissions from Fossil Energy Extracted from Federal Lands and Waters* in which we developed a preliminary estimate of the magnitude of ultimate GHG emissions[2] associated with fossil fuels for the years 2008–2010 – for example, onshore and offshore oil and natural gas, natural gas liquids, coal, and coalbed methane – that leaseholders[3] extract from federal lands. The report also included an overview of many types of indirect emissions that could result from fossil fuel extraction, such as emissions from transporting fossil fuels from federal lands to refineries. The report did not address GHG emissions resulting from wind, solar, geothermal, or biomass activities.[4]

1. The term "federal lands" includes all offshore areas that the federal government leases to private companies, as well as onshore lands in this report.

2. Ultimate GHG emissions refer to carbon dioxide (CO_2), methane, and nitrous oxide emissions that result from fossil fuel extracted from federal lands (i.e., the quantity of gas emitted if an amount of a fossil fuel was combusted downstream in various applications, such as coal-fired power plants).

3. In both the 2012 report and the current update, we focus on GHG emissions resulting from the extraction of fossil fuels from federal lands by private companies holding leases for these purposes, even in instances where the federal government holds subsurface rights but does not hold surface rights. As such, the 2012 report and the current report does not account for emissions resulting from the extraction of fossil fuels in instances where the federal government owns the surface rights but private or other government entities own the subsurface rights.

4. In both the 2012 report and the current update, we cover a subset of energy extraction activities on federal lands and waters. We focus on fossil fuel extraction from federal lands, where the U.S. Department of the Interior (DOI) manages subsurface leasing. The DOI manages subsurface leasing for all federal lands, including public lands under the jurisdiction of the Bureau of Land Management (BLM) and other lands under the jurisdiction of other federal surface management agencies. The data that we collected from DOI sources for the analysis includes information on all leases that the DOI manages.

Our current report provides an updated analysis of the magnitude of GHG emissions currently accounted for from federal lands and waters. Specifically, we add emissions estimates for calendar year 2012 using the same methodology utilized in the 2012 analysis.[5] We also include an appendix characterizing indirect emissions from natural gas and oil production. We focus on methane emissions from natural gas and oil production to highlight the importance of these emissions and their contribution to climate change. These emissions also highlight the growing importance of unconventional – fracking and tight gas – natural gas production and venting and flaring during oil production. Methane is 25 times more potent than CO_2 as a GHG, and emissions from natural gas and oil production could be significant.

1.1 Background

Federal lands and waters supply a considerable portion of the nation's fossil energy resources, including approximately 42% of produced coal, 26% of crude oil, and 13% of natural gas.[6] Rather than developing, extracting, transporting, and converting these resources directly, federal agencies typically operate through permits, leases, contracts, and concessions to private sector firms.

> **Total U.S. GHG emissions and emissions related to energy consumption**
>
> The U.S. Environmental Protection Agency (EPA) produces an annual GHG inventory every year that provides estimates of the nation's source- and sector-specific emissions of CO_2, methane (CH_4), nitrous oxide (N_2O), and other GHGs. According to EPA's most recent (2014) inventory, GHG emissions in the United States in 2012, the most recent year for which data were available, totaled approximately 6,526 million metric tons of carbon dioxide equivalent ($MMTCO_2e$). Energy-related GHG emissions totaled 5,499 $MMTCO_2e$.
>
> Source: U.S. EPA, 2014b.

Executive Order (E.O.) 13514, *Federal Leadership in Environmental, Energy, and Economic Performance* (74 Federal Register 52117, October 9, 2009; The White House Office of the Press Secretary, 2009), directed federal agencies to meet a range of energy, water, and waste-reduction targets. The E.O. included requirements that federal agencies inventory, report, and adopt targets for reducing their direct and indirect GHG emissions. The CEQ developed the *Federal Greenhouse Gas Accounting and Reporting Guidance* (CEQ, 2010b) to provide federal agencies with clear information on which emissions fall within the scope of E.O. 13514 and how to calculate these emissions. The report included guidance on how to quantify emissions resulting from a range of source categories. Table 1 lists the GHG emissions source categories included in the guidance and ultimately accounted for in the federal government inventory. Federal government agencies reported their emissions for 2010 and made them public in April 2011.

5. Our current report draws heavily on the 2012 report for structure, methodology, and presentation.

6. We collected data for fossil fuel produced from federal lands for this analysis (BOEMRE, 2014; ONRR, 2014b), and data on total fossil fuel production for the entire United States (EIA, 2014b, 2014c, 2014d).

Table 1. Sources of emissions accounted for in the *Greenhouse Gas Emissions Inventory for the Federal Government: 2010 Data*, released by the CEQ in April 2011

On-site fuel combustion
Non-highway vehicles, aircraft, ships, and equipment
Passenger fleet vehicles
Fluorinated gases and other fugitive emissions
On-site wastewater treatment
On-site landfills, solid waste facilities, and incinerators
Manufacturing and industrial process emissions
Purchased electricity
Purchased biomass energy
Purchased steam and hot water
Purchased chilled water
Purchased combined heat and power, electricity, steam, and hot water
Transmission and distribution losses from purchased electricity
Federal employee business air travel
Federal employee business ground travel
Federal employee commuting
Off-site wastewater treatment
Off-site solid waste disposal

Source: CEQ, 2011.

In the report *Greenhouse Gas Emissions Inventory for the Federal Government: 2010 Data*, the CEQ estimated that GHG emissions from federal government operations totaled approximately 66.4 $MMTCO_2e$ in 2010. According to the inventory, DOI, which is responsible for managing a significant majority of federal fossil fuel leases, contributed approximately 1.3 $MMTCO_2e$ (CEQ, 2011). The CEQ guidance did not include requirements for reporting emissions associated with activities, including fossil fuel extraction on federal lands, which are subject to federal agency oversight but that private entities conduct. Federal government agencies, therefore, did not estimate these emissions in the reports they compiled for the inventory.[7]

7. Federal agencies are required to account for GHG emissions under other obligations. For example, federal agencies are obligated under the National Environmental Policy Act (NEPA), 42 U.S.C. § 4321, et seq., to analyze the impacts of major federal actions that have significant impacts on the environment, including the impacts on global climate change. However, emissions resulting from federal leasing are not explicitly addressed in the NEPA guidance for federal agencies (CEQ, 2010a). Agencies within the DOI are additionally bound by Secretarial Order 3289, which requires the analysis of potential climate change effects when undertaking planning, setting priorities for scientific research, developing management plans, and making major decisions regarding the potential use of resources.

Our first report on behalf of The Wilderness Society, entitled *Greenhouse Gas Emissions from Fossil Energy Extracted from Federal Lands and Waters,* estimated that ultimate downstream GHG emissions from federal lands in 2010 could have been more than 20 times the estimate of total GHG emissions in the CEQ report.

1.2 Overview

The remainder of this report is structured as follows:

- ***Section 2 – Methodology*.** In this section, we describe the methodology used in the analysis. We include an overview of the process we used to quantify ultimate GHG emissions from fossil fuel extraction on federal lands by private leaseholders.

- ***Section 3 – Results*.** Here, we summarize the results of the quantitative analysis of ultimate GHG emissions resulting from the extraction of fossil fuels on federal lands by private leaseholders in 2012. We provide fuel-, location-, and GHG-specific estimates.

- ***Section 4 – Conclusions*.** This section presents key points based on the analysis we describe in this report.

- ***References.*** This section includes references that we cite in the report.

- ***Appendix – Indirect GHG Emissions Associated with Natural Gas and Oil Production.*** Here, we summarize the results of a literature review of indirect GHG emissions from natural gas production. We focus on methane emissions from natural gas and oil production, and quantify emissions for various scenarios involving venting, flaring, and unintentional leaks of natural gas.

2. Methodology

This section describes the methodology used for this analysis. We include an overview of the process used to quantify ultimate GHG emissions from fossil fuel extraction from federal lands by private leaseholders. We discuss data collection including the quantities of fossil fuels extracted from federal lands by private leaseholders, energy flows, and emissions factors. Then we present the steps involved in data processing: converting units, matching quantities of fossil fuels to sectors and emissions factors, and performing calculations.

2.1 Methodology for Quantifying Ultimate GHG Emissions from Fossil Fuel Extraction from Federal Lands by Private Leaseholders

Quantifying ultimate GHG emissions from fossil fuel extraction on federal lands by private leaseholders involved two broad steps: data collection and data processing. This section describes the steps involved in each step.

2.1.1 Data collection

This section describes the data collection portion of the analysis, including the types of data we collected and our data sources.

Quantities of fossil fuels extracted from federal lands by private leaseholders

The primary data collection effort involved gathering information on the quantities of fossil fuels extracted from federal lands by private leaseholders, based on reports by federal government agencies. The data included the quantity of fuel extracted by relevant metric (e.g., barrels of oil, cubic feet of natural gas, and short tons of coal), the year,[8] and the state in which the lease was held (or region, in the case of offshore data). We collected data for the following fuel categories: onshore and offshore oil, onshore and offshore natural gas, natural gas liquids, coal, and coalbed methane.[9]

We collected data from several DOI sources. Table 2 provides a list of these sources by fuel type.

8. Our analysis used the calendar year as our unit of temporal measure.

9. For onshore oil, onshore natural gas, natural gas liquids, coal, and coalbed methane, quantities were only available in terms of sales volume (as indicated in royalty reports), rather than production volume. In theory, sales volumes for a given year can be smaller or larger than production volumes for that year because companies can vary sales depending on market conditions. For offshore oil and natural gas, quantities were available in terms of production volume.

Table 2. Sources of data on quantities of fossil fuels produced from federal leases

Fossil fuel	Federal government agency and program
Coal and coalbed methane	DOI, BLM – Public Land Statistics: Federal Coal Leases (BLM, 2011) DOI, Office of Natural Resources Revenue (ONRR) – Reported Royalty Revenues (ONRR, 2014b)
Oil, natural gas (onshore), and natural gas liquids	DOI, ONRR – Reported Royalty Revenues (ONRR, 2011, 2014b)
Oil, natural gas (onshore and offshore)	DOI, ONRR – Oil and Natural Gas Report (ONRR, 2014a)
Oil and natural gas (offshore)	DOI, Bureau of Ocean Energy Management, Regulation, and Enforcement – Outer Continental Shelf Oil and Gas Production (BOEMRE, 2014)

Energy flows

We also collected information that enabled us to match the quantities of fuel to specific downstream combustion methods, each of which has a distinct set of emissions factors for key GHGs.[10] We discuss the importance of this fuel type-combustion method matching in the following section. Estimates for 2012 were derived from the Energy Information Administration's (EIA's) *Annual Energy Outlook 2012 with Projections to 2035*, which provided information for the base year, 2012, as well as future projections (EIA, 2009b, 2010, 2011a, 2012a, 2013).

Emissions factors

We identified emissions conversions factors to determine the quantity of GHGs emitted for each unit of fossil fuel extracted. The most widely accepted emissions factors used to calculate GHG emissions were provided in the Intergovernmental Panel on Climate Change's (IPCC's) *IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC, 2006). These guidelines included tables that presented estimates of the kilograms of CO_2, CH_4, and N_2O emitted for every terajoule, or measure of energy content, of energy consumed. These tables included specific fossil fuel- and combustion-type emissions factors. For example, IPCC guidelines provided emissions factors to estimate the kilograms of CH_4, CO_2, and N_2O emitted for every terajoule of energy consumed from burning sub-bituminous coal in a coal-fired power plant for electricity generation.

10. For example, coal combustion for electricity generation has a different set of emissions factors from oil combustion for residential heating.

For the transportation sector, the IPCC presented a number of subsector-specific sets of emissions factors based on the type of fuel used and the combustion process used in each subsector (e.g., for on-road vehicles, IPCC presented different sets of emissions factors for light-duty vehicles and heavy-duty vehicles). We also collected data on the percentages of transportation-related energy that the different subsectors used from EIA's *Annual Energy Outlook 2014 with Projections to 2040* (EIA, 2014a).

For coal, GHG emissions vary depending on the type of coal combusted (e.g., lignite versus sub-bituminous). We collected information on the type of coal extracted in states where private leaseholders extract coal from federal lands from the DOI's *2010 Public Lands Statistics: Federal Coal Leases* (BLM, 2011), which includes reports of the states from which private leaseholders extract coal, and EIA's *Annual Coal Report – 2009* (EIA, 2009a), which provides information on the typical type of coal extracted in each state. Table 3 combines these two sets of information.

Table 3. Coal type by state (states with private leasing on federal lands for coal extraction)

States with private leasing for coal	Dominant coal type
Alabama	Bituminous
Arizona	Bituminous
Colorado	Bituminous
Kentucky	Bituminous
Montana	Sub-bituminous
New Mexico	Sub-bituminous
North Dakota	Lignite
Oklahoma	Bituminous
Ohio	Bituminous
Utah	Bituminous
Washington	Bituminous
Wyoming	Sub-bituminous

Sources: EIA, 2009a; BLM, 2011.

2.1.2 Data processing

To calculate the ultimate GHG emissions from fossil fuel extraction on federal lands by private leaseholders, the data described above were processed in several ways. This section describes the steps we took.

Converting units

The calculation of ultimate GHG emissions involves a number of conversions. For example, the quantities of fossil fuels extracted by private leaseholders from federal lands were reported in volume-based metrics (e.g., short tons, barrels, cubic feet), but the emissions factors provided by the IPCC were characterized in terms of the amount of energy produced by burning the fossil fuel. For this reason, the quantities of fossil fuel extracted were converted into energy-based measures using common conversion factors, such as those available at http://www.natgas.info/html/natgasunitsconversion.html (Chandra, 2011). EIA and the International Energy Agency also provided conversion information that was used in this analysis [http://www.eia.gov/kids/energy.cfm?page = about_energy_conversion_calculator-basics (EIA, 2011b) and http://www.i.e.a.org/stats/unit.asp (IEA, 2011), respectively].

Matching quantities of fossil fuels to sectors and emissions factors

As noted above, GHG emissions from each fuel type can be determined by multiplying a given quantity of combusted fuel by an emissions factor that is specific to a particular type of combustion. For each of the five sectors identified by the EIA, corresponding sets of combustion-type emissions factors were identified in the *IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC, 2006). For example, the guidelines offered default sets of emissions factors for combustion in stationary power plants, which we deemed appropriate for coal; or combustion in residential settings, which were viewed as appropriate for natural gas.

Information from the EIA was used to classify combustion type by fuel type. These classification "splits" were determined for 2012 by consulting the *Annual Energy Review* publications (EIA, 2012b).

Performing calculations

Equation 1 provides a general illustration of how the above information was combined to produce an estimate of the total amount of GHGs emitted from the combustion of a particular quantity of fossil fuel:

Equation 1. Simplified illustration of equation used to calculate GHG emissions.

$$\begin{aligned} &\mathit{Quantity\ of\ GHG\ emitted\ (in\ kilograms)} \\ &\quad = \sum \mathit{Quantity\ of\ fossil\ fuel\ (in\ terajoules)} \\ &\quad \times \mathit{Emissions\ factor\ (in\ kilograms\ per\ terajoule)} \times \mathit{Sector\ weight} \end{aligned}$$

where the sector weight represents the percentage of the quantity of fossil fuel that was consumed in the specific sector (e.g., transportation), thus using the sector-specific set of emissions factors, and the total amount of GHG emitted for a given quantity of fossil fuel is a sum of the calculations for each sector.

Calculations were run to determine the ultimate GHG emissions from federal leases, based on the following:

- Year
- GHG (i.e., CO_2, CH_4, or N_2O)
- Carbon dioxide equivalent (CO_2e; accounting for all three GHGs)[11]
- Fossil fuel type
- Location (onshore versus offshore).

We present the results of these calculations in Section 3.1.

3. Results

This section presents the results of the analysis of ultimate GHG emissions from extraction of fossil fuels from federal lands by private leaseholders. We provide estimates of ultimate GHG emissions by fuel, location, and GHG for 2012.

3.1 Quantification of Ultimate GHG Emissions from Fossil Fuel Extraction from Federal Lands by Private Leaseholders

Table 4 presents estimates of the GHG emissions associated with fossil fuels extracted from federal lands by private leaseholders for 2012.[12] According to this analysis, in 2012 the GHG emissions resulting from the extraction of fossil fuels from federal lands by private leaseholders totaled approximately 1,344 $MMTCO_2e$.

GHG equivalencies

The GHG emissions from federal lands total 1,344 $MMTCO_2e$ in 2012. These GHG emissions are equivalent to the annual GHG emissions emitted by 283,000,000 passenger vehicles.

Source: U.S. EPA, 2014b.

Figure 1 shows the percentage breakdown of emissions by fossil fuel in 2012.

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11. CO_2e were based on the 100-year global warming potentials (GWPs) for these gases, as cited in the IPCC's Fourth Assessment Report on Climate Change (IPCC, 2007).

12. Note that the estimates we present in Tables 5 through 9 are rounded.

Table 4. GHG emissions associated with fossil fuels extracted from federal lands by private leaseholders in 2012

Fossil fuel	Metric tons of CH_4	Metric tons of CO_2	Metric tons of N_2O	Total $MTCO_2e$
Oil (onshore)	2,999	56,346,510	2,985	57,311,142
Oil (offshore)	11,368	213,556,048	11,315	217,212,051
Natural gas (onshore)	12,358	144,135,798	480	144,587,927
Natural gas (offshore)	8,390	97,851,370	326	98,158,313
Natural gas liquids	11,161	26,134,702	503	26,563,487
Coal	13,080	765,241,950	12,037	769,155,909
Coalbed methane	2,656	30,973,401	103	31,070,559
Total	62,012	1,334,239,779	27,749	1,344,059,388

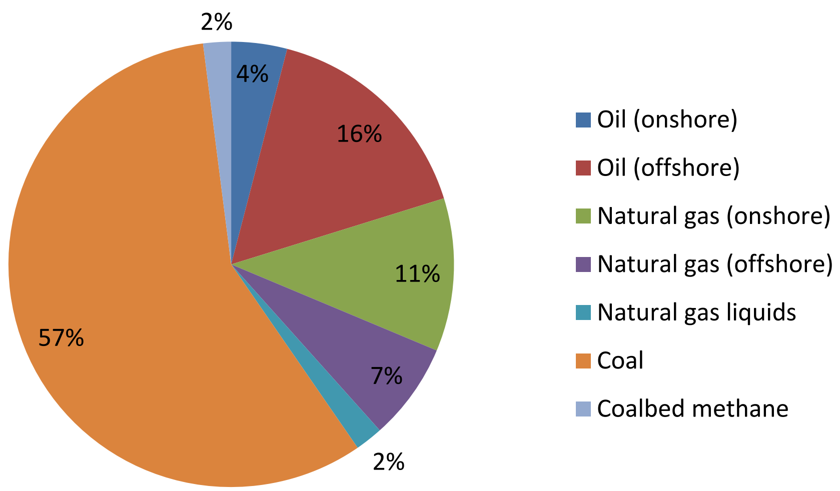

Figure 1. Percentage of total $MTCO_2e$ emissions associated with fossil fuels extracted from federal lands by private leaseholders in 2012.

The estimates above suggest how fossil fuel extraction from federal lands by private leaseholders may contribute to the total amount of GHG emissions included in EPA's national GHG inventory. As noted above, EPA produces a GHG inventory every year that includes estimates of the nation's source- and sector-specific emissions of CO_2, CH_4, N_2O, and other GHGs. According to the 2014 inventory, GHG emissions in the United States in 2012 totaled approximately 6,500 MMTCO_2e, of which 5,500 MMTCO_2e came from energy consumption. Our current analysis suggests that ultimate emissions from these leases could account for approximately 21% of total U.S. GHG emissions and 24% of energy-related GHG emissions.

As the tables and figures show, coal extraction was consistently the largest contributor to overall emissions in 2012. Combined, coal and coalbed methane accounted for greater than half of all MTCO_2e. The tables also show the considerable contribution of onshore and offshore natural gas extraction to total emissions of CH_4. This contribution is significant, given the GWP of CH_4; 1 metric ton of CH_4 emitted is equal to approximately 25 metric tons of CO_2 emitted (IPCC, 2007). Table 5 presents coal production and emissions totals by state in 2012.

Indirect methane emissions from natural gas production

Methane emissions from natural gas venting on public lands for which royalties are paid could total almost 1.3 million metric tons CO_2e.

CO_2 emissions from natural gas flaring on public lands for which royalties are paid could total 173,077 metric tons CO_2. These emissions are significantly higher when accounting for emissions from vented and flared natural gas from public lands for which royalties have not been paid.

Source: Appendix to this report.

Table 5. Coal production and emissions by state in 2012

	Type of coal	Sales volume (short ton)	CH_4 emissions (metric tons)	CO_2 emissions (metric tons)	N_2O emissions (metric tons)	CO_2e (metric tons)
Alabama	Bituminous	1,934,725	80	4,634,439	73	4,658,333
Colorado	Bituminous	20,586,124	850	49,311,984	782	49,566,232
Kentucky	Bituminous	207,931	9	498,078	8	500,646
Montana	Sub-bituminous	21,811,626	656	38,701,250	604	38,897,676
New Mexico	Sub-bituminous	4,957,756	149	8,796,747	137	8,841,394
North Dakota	Lignite	3,839,502	86	531,882	79	557,567
Oklahoma	Bituminous	352,171	15	843,590	13	847,940
Utah	Bituminous	13,392,915	553	32,081,377	509	32,246,786
Wyoming	Sub-bituminous	354,972,808	10,683	629,842,604	9,831	633,039,334
Total		422,055,558	13,080	765,241,950	12,037	769,155,909

Note: Totals may not sum due to rounding.

Table 6 presents the total GHG emissions split by onshore and offshore production of fossil fuels. As the table shows, approximately 77% of the emissions evaluated in 2012 came from onshore locations. This was largely driven by the dominance of coal extraction from federal lands, which only occurred onshore. Figure 2 presents the amount of fossil fuels extracted onshore and offshore.

Table 6. GHG emissions (in CO_2e) associated with fossil fuels extracted from federal lands by private leaseholders by location

Fossil fuel	2012 $MTCO_2e$
Onshore	1,028,689,025
Offshore	315,370,364

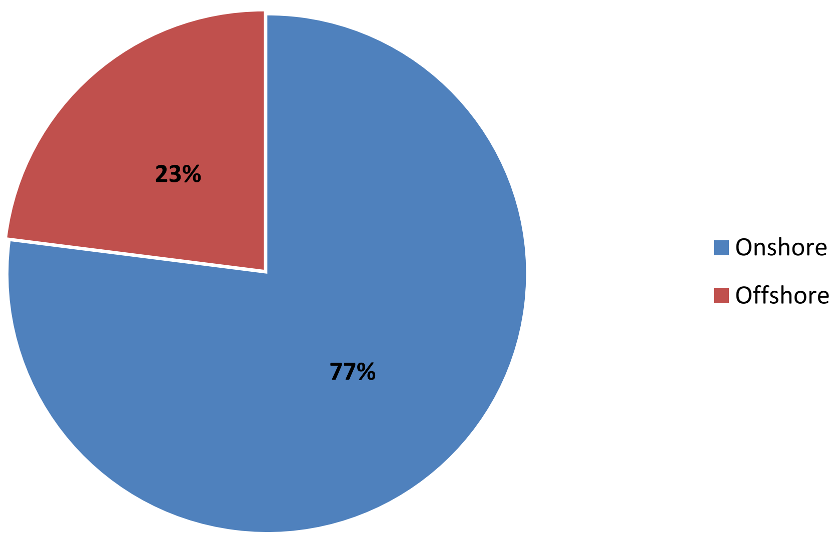

Figure 2. Percentage of $MTCO_2e$ emissions associated with fossil fuels extracted from federal lands by private leaseholders, by location of extraction.

4. Conclusions

This report presents a preliminary estimate of the magnitude of GHG emissions associated with fossil fuel extraction from federal lands by private leaseholders. Our findings suggest that in 2012, the most recent year for which total U.S. GHG emissions data were available, the estimated 1,344 $MMTCO_2e$ in ultimate downstream GHG emissions from fossil fuel extraction from federal lands by private leaseholders could have accounted for approximately 21% of total U.S. GHG emissions and 24% of energy-related GHG emissions. We include an appendix in this report that presents the results of a quantitative analysis of indirect emissions associated with natural gas and oil production.

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Appendix. Indirect GHG Emissions Associated with Natural Gas and Oil Production

Indirect emissions are associated with nearly all stages of fossil fuel extraction, broadly defined as any GHG emissions caused by the exploration, production, refinement, or transportation of fossil fuels that are not otherwise accounted for in the ultimate GHG emissions calculations we describe in Section 2.1.

In this appendix, we quantify indirect GHG emissions[13] associated with natural gas and oil production including venting, flaring, and fugitive emissions. Our focus is on CH_4 emissions from natural gas and oil production, the second largest contributor to climate change after CO_2. CH_4 is 25 times more potent than CO_2 over a 100-year time horizon (IPCC, 2007).

Significant CH_4 emissions are associated with natural gas and oil production. This is driven by the increase in unconventional gas production methods, such as shale and tight gas, as well as venting and flaring during oil production. But, CH_4 emissions are not well quantified and are worthy of further research. Specifically, characterization and accounting for leaks during natural gas production are subject to ongoing review. For example, EPA has revised CH_4 emissions estimates from the natural gas sector several times in the past few years (U.S. EPA, 2014a).

Natural gas venting and flaring data

ONRR collects data on royalties for natural gas specifically reported as "gas lost – flared or vented" on public lands. These data do not separate venting and flaring quantities nor do they differentiate between conventional and unconventional natural gas production. Because we do not know the fraction of natural gas that producers vent versus flare, we present two emissions scenarios for this specifically reported volume of gas lost to venting and flaring – a scenario that assumes 100% venting and a scenario that assumes 100% flaring – in order to provide a range of possible emissions using the ONRR data. We also assume that this venting is occurring in the production, rather than the pipeline, stage.

ONRR also collects reported data on venting and flaring from U.S. natural gas and oil production in its Oil and Gas Operations Report (OGOR). These data are separated into venting and flaring categories, but include both federal and some non-federal leases that are part of the same communitization agreement.[14] Because we do not know the fraction of these releases that come

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13. We have included CH_4 and CO_2 in the indirect emissions estimates. Natural gas also includes nitrogen and non-methane volatile organic compounds, which are not included in the current analysis.

14. In most cases a portion of the federal leases are managed as part of communitization agreements, which are a collection of federal and some non-federal leases that draw from the same oil and gas reservoir. A non-federal lease could include an American Indian, state, and/or fee lease.

directly from federal lands, the estimates provided reflect venting and flaring emissions for both federal and some non-federal sources.

Emissions scenarios

Venting and fugitive (unintentional) leaks of natural gas emit primarily CH_4, while natural gas flaring emits primarily CO_2. To evaluate indirect GHG emissions associated with natural gas production on federal lands, we present the following four emissions scenarios:

1. ***Scenario 1:*** 100% venting, using ONRR data on royalties reported for venting and flaring in natural gas production (ONRR, 2014b)

2. ***Scenario 2:*** 100% flaring, using ONRR data on royalties reported for venting and flaring in natural gas production (ONRR, 2014b)

3. ***Scenario 3:*** Venting and flaring for onshore and offshore U.S. natural gas and oil production, using ONRR OGOR data (ONRR, 2014a)

4. ***Scenario 4:*** CH_4 emissions from a literature review.

Scenario 1: 100% venting, using ONRR data on royalties reported for venting and flaring in natural gas production

The first step in calculating venting emissions based on natural gas reported as lost to venting or flaring from the ONRR royalty data was to convert the volume of natural gas (Mcf) into the mass of natural gas (pounds) using a natural gas density of 0.042 lb/cf (NETL, 2011). The second step was to estimate the emissions of CH_4 and CO_2, assuming that natural gas in the production stage is 78.8% CH_4 and 1.52% CO_2 by mass (NETL, 2011), and convert them to metric tons (2,205 lb/metric ton). The third step was to convert the CH_4 emissions to CO_2e metric tons using a GWP factor of 25 (IPCC, 2007).

We present the CH_4, CH_4–CO_2e, and CO_2 emissions associated with the ONRR royalties data reported for natural gas reported as lost to venting or flaring assuming 100% venting in Table A.1.

Table A.1. CH_4 and CO_2 emissions associated with natural gas venting: ONRR royalties reported data for natural gas reported as lost to venting or flaring

Emissions (metric tons)	2008	2009	2010	2011	2012
CH_4	2,538	2,285	1,852	5,846	51,080
CH_4–CO_2e	63,447	57,122	46,312	146,149	1,277,009
CO_2	49	44	36	113	985

Scenario 2: 100% flaring, using ONRR data on royalties reported for venting and flaring in natural gas production

The first step in calculating flaring emissions based on natural gas reported as lost to venting or flaring from the ONRR royalty data was to convert the volume of natural gas (Mcf) into the mass of natural gas (pounds) using a natural gas density of 0.042 lb/cf (NETL, 2011). The second step was to apply emissions factors of 2.67 lb CO_2/lb of flared natural gas and 1.53E-02 lb CH_4/lb of flared natural gas (NETL, 2011) to estimate the mass emissions of CO_2 and CH_4 and convert them to metric tons (2,205 lb/metric ton). The third step was to convert the CH_4 emissions to CO_2e metric tons using a GWP factor of 25 (IPCC, 2007).

We present the CH_4, CH_4–CO_2e, and CO_2 emissions associated with the ONRR royalties data reported for natural gas reported as lost to venting or flaring assuming 100% flaring in Table A.2.

Table A.2. CH_4 and CO_2 emissions associated with natural gas flaring: ONRR royalties reported data for natural gas reported as lost to venting or flaring

Emissions (metric tons)	2008	2009	2010	2011	2012
CH_4	49	44	36	114	992
CH_4–CO_2e	1,232	1,109	899	2,838	24,795
CO_2	8,599	7,742	6,277	19,808	173,077

We assume that actual emissions based on the ONRR royalties data are bounded by these two scenarios since emissions are both flared and vented.

Scenario 3: Venting and flaring for onshore and offshore U.S. natural gas and oil production, using ONRR OGOR data

Table A.3 presents GHG emissions using both onshore and offshore venting and flaring data from the OGOR. As noted above, the OGOR data include reported volumes of natural gas venting and flaring from both natural gas and oil production, and include both federal and some non-federal leases. Table A.4 presents GHG emissions from the onshore venting and flaring data from the OGOR data, and Table A.5 presents GHG emissions from the offshore venting and flaring data from the OGOR data.

Table A.3. CH_4 and CO_2 emissions from venting and flaring gas in oil and natural gas production: OGOR data

Emissions (metric tons)	2008	2009	2010	2011	2012	2013
CH_4	87,731	91,138	118,900	160,460	172,217	192,136
CH_4–CO_2e	2,193,265	2,278,442	2,972,493	4,011,488	4,305,431	4,803,391
CO_2	2,722,902	2,410,903	2,435,347	2,689,634	3,492,473	3,964,003

Table A.4. CH_4 and CO_2 emissions from venting and flaring gas in onshore oil and natural gas production: OGOR data

Emissions (metric tons)	2008	2009	2010	2011	2012	2013
CH_4	83,358	87,458	90,564	96,710	117,095	126,221
CH_4–CO_2e	2,083,956	2,186,444	2,264,106	2,417,752	2,927,378	3,155,531
CO_2	2,104,544	1,861,373	1,844,068	2,323,508	3,018,254	3,635,350

Table A.5. CH_4 and CO_2 emissions from venting and flaring gas in offshore oil and natural gas production: OGOR data

Emissions (metric tons)	2008	2009	2010	2011	2012	2013
CH_4	4,372	3,680	28,335	63,749	55,122	65,914
CH_4–CO_2e	109,308	91,997	708,387	1,593,736	1,378,053	1,647,860
CO_2	618,358	549,529	591,278	366,126	474,219	328,654

Scenario 4: CH_4 emissions from a literature review

The venting and flaring emissions discussed above do not account for all leakage. To provide a more comprehensive characterization of CH_4 emissions that may be associated with natural gas production, including unintentional or "fugitive" leaks, we conducted a review of recent studies that have estimated leakage rates as a percentage of the production over the lifecycle of a well. We found a wide range of estimates for CH_4 emissions estimates for all stages of natural gas production. The following tables present CH_4 and CO_2 emissions resulting from scenarios derived through the literature review. We recognize that different leakage rates could be applied. The CH_4 leakage estimates are applied to ONRR onshore gas production data. We calculate CH_4 and CO_2 emissions for the low and high estimates of CH_4 leakage for both upstream/midstream and downstream from unconventional (shale and tight gas) and conventional natural gas production. Upstream leakage refers to emissions at the well site, midstream leakage refers to emissions at gas processing plants, and downstream leakage refers to emissions from transmissions pipelines and storage and distribution systems.

CH_4 emissions are calculated using either bottom-up or top-down studies. CH_4 emissions for official inventories are estimated from the "bottom up," in which emissions factors are multiplied by activity data from U.S. GHG inventories (e.g., the EPA GHG Inventory). In contrast, top-down studies use direct CH_4 measurements in natural gas production basins (Petron et al., 2012; Karion, 2013). We include estimates derived from both methodologies in the scenarios below.

The first step in calculating emissions for the leakage scenarios was to convert the relevant ONRR-reported volumes of natural gas (Mcf) into the mass of natural gas (pounds) using a natural gas density of 0.042 lb/cf (NETL, 2011). The second step was to assign this mass to conventional and unconventional production methods using available national information on the distribution of natural gas production by these methods for the years considered in this study. The third step was to adjust these reported totals using the range of the combined upstream and midstream leakage estimates described below to develop a range of potential wellhead production estimates. Fourth, we estimate the leakage of CH_4 and CO_2, assuming that natural gas in the upstream and midstream production stages is 78.8% CH_4 and 1.52% CO_2 by mass, and 93.4% CH_4 and 0.47% CO_2 by mass in the downstream stage (NETL, 2011). The range of calculated leakages was then converted to metric tons (2,205 lb/metric ton). The final step was to convert the CH_4 emissions to CO_2e metric tons using a GWP factor of 25 (IPCC, 2007).

We have included bottom-up and top-down estimates of percent CH_4 leakage (combined upstream and midstream methane emissions) from unconventional natural gas production in Table A.6. In applying these rates, we assumed the rates effectively address the mass of natural gas being leaked and used it to calculate CO_2 as well as CH_4 leakage. As stated above, the range of emissions estimates is significant. These leakage rates, which reflect the full lifecycle of a well, range from 0.6% to 17.3%.[15]

15. Other recent studies that are not included in the compiled emissions estimates illustrate the uncertain nature of these estimates. In their 2013 study, Allen et al. (2013) found lower CH_4 emissions than EPA estimates, using scaled actual measurements. The Allen et al. (2013) study covered 190 onshore natural gas sites in the United States. Another study, by Miller et al. (2013), used atmospheric data for the United States; the authors found that EPA inventories underestimated CH_4 emissions. Still another study, Brandt et al. (2014), found that measured natural gas emissions rates were higher than inventory estimates, possibly because of a small number of "superemitting" wells.

Table A.6. Estimates of upstream and midstream methane emissions from unconventional gas systems(% CH_4 produced over lifecycle of a well)[a]

Stephenson et al. (2011)	0.6%
U.S. EPA (2011)[b]	3.0%
Howarth et al. (2011)	3.3%
Caulton et al. (2014)	2.8–17.3%
Petron et al. (2012)	2.3–7.7%
Karion (2013)	6.2–11.7%

a. The CH_4 estimates were reviewed in Howarth et al. (2012b) and Caulton et al. (2014).
b. The EPA estimate in this table is calculated in Howarth et al. (2012a), using national emissions from EPA reports and national gas production data from DOE.

Using the lowest and highest combined upstream and midstream leakage estimates from the studies listed above in Table 6, we calculated the range of potential indirect CH_4 and CO_2 leakage from unconventional natural gas produced on public lands, as shown in Tables A.7 and A.8.

Table A.7. CH_4 and CO_2 emissions associated with natural gas production from public lands: Unconventional gas, upstream and midstream, low leakage rate scenario (0.6% CH_4 leakage)

Emissions (metric tons)	2008	2009	2010	2011	2012
CH_4	98,488	91,288	108,377	122,197	128,207
CH_4–CO_2e	2,462,211	2,282,210	2,709,427	3,054,924	3,205,169
CO_2	1,900	1,761	2,091	2,357	2,473

Table A.8. CH_4 and CO_2 emissions associated with natural gas production from public lands: Unconventional gas, upstream and midstream, high leakage rate scenario (17.3% CH_4 leakage)

Emissions (metric tons)	2008	2009	2010	2011	2012
CH_4	3,413,194	3,163,672	3,755,892	4,234,831	4,443,106
CH_4–CO_2e	85,329,853	79,091,790	93,897,299	105,870,786	111,077,659
CO_2	65,838	61,025	72,449	81,687	85,705

We provide estimates for combined upstream and midstream leakage from conventional natural gas production below. Table A.9 presents leakage estimates from the literature, expressed as the percentage of CH_4 produced over the lifecycle of a well. As with the unconventional production estimates above, we assumed the rates effectively address the mass of natural gas being leaked and used it to calculate CO_2 leakage as well as CH_4 leakage. The estimates in the studies included leakage rates that range from 0.4% to 2.0%, as we present in Table A.9.

Table A.9. Estimates of upstream and midstream methane emissions from conventional gas systems (% CH_4 produced over the lifecycle of a well)[a]

U.S. EPA (2011)	1.6%
Howarth et al. (2011)	1.4%
Hayhoe et al. (2002)	1.2%
Hultman et al. (2011)	1.3%
Venkatesh et al. (2011)	1.8%
Burnham et al. (2011)	2.0%
Stephenson et al. (2011)	0.4%
Cathles et al. (2012)	0.9%

a. The CH_4 estimates from each study were reviewed in Howarth et al. (2012b).

Using the lowest and highest combined upstream and midstream leakage estimates from the studies listed above in Table A.9, we calculated the resulting CH_4 and CO_2 leakage that may be associated with natural gas produced conventionally on public lands. Table A.10 presents the low-leakage rate scenario and Table A.11 presents the high-leakage rate scenario for upstream and midstream emissions.

Table A.10. CH_4 and CO_2 emissions associated with natural gas production from public lands: Conventional gas, upstream and midstream, low-leakage rate scenario (0.4% CH_4 leakage)

Emissions (metric tons)	2008	2009	2010	2011	2012
CH_4	102,852	76,172	76,568	60,288	55,494
CH_4–CO_2e	2,571,293	1,904,301	1,914,211	1,507,212	1,387,359
CO_2	1,984	1,469	1,477	1,163	1,070

Table A.11. CH_4 and CO_2 emissions associated with natural gas production from public lands: Conventional gas, upstream and midstream, high-leakage rate scenario (2.0% CH_4 leakage)

Emissions (metric tons)	2008	2009	2010	2011	2012
CH_4	522,655	387,078	389,093	306,364	282,002
CH_4–CO_2e	13,066,366	9,676,958	9,727,318	7,659,098	7,050,048
CO_2	10,082	7,466	7,505	5,910	5,440

Recent estimates in peer-reviewed literature for downstream leakage of CH_4 from natural gas systems range from 0.07% to 10% of the CH_4 produced over the lifecycle of a well. Downstream leakage refers to leakage that occurs in storage, and transmission and distribution pipelines. Table A.12 presents the range of downstream CH_4 leakage rates from various studies.

Table A.12. Estimates of downstream methane emissions (% CH_4 produced over the lifecycle of a well)[a]

Hayhoe et al. (2002)	0.2–10%
Lelieveld et al. (2005)	1.0–2.5%
Howarth et al. (2011)	1.4–3.6%
U.S. EPA (2011)	0.9%
Jiang et al. (2011)	0.4%
Hultman et al. (2011)	0.9%
Venkatesh et al. (2011)	0.4%
Burnham et al. (2011)	0.6%
Stephenson et al. (2011)	0.07%
Cathles et al. (2012)	0.7%

a. The CH_4 estimates from each study were reviewed in Howarth et al. (2012b) and Caulton et al. (2014).

Tables A.13 and A.14 present the low and high scenarios for CH_4 and CO_2 emissions for downstream emissions, respectively, for natural gas produced unconventionally from public lands. The low scenarios are based on using the lowest leakage rates for the combined upstream and midstream leakage rates as well as the lowest downstream leakage rate (see Tables 6 and 12). The high scenarios are based on using the highest leakage rates for the combined upstream and midstream leakage rates as well as the highest downstream leakage rate (see Tables 6 and 12).

Table A.13. CH_4 and CO_2 emissions associated with natural gas production from public lands: Unconventional gas, downstream, low scenario (0.07% CH_4 leakage)

Emissions (metric tons)	2008	2009	2010	2011	2012
CH_4	13,619	12,624	14,987	16,898	17,729
CH_4–CO_2e	340,481	315,590	374,666	422,443	443,219
CO_2	69	64	75	85	89

Table A.14. CH4 and CO_2 emissions associated with natural gas production from public lands: Unconventional gas, downstream, high scenario (10.0% CH_4 leakage)

Emissions (metric tons)	2008	2009	2010	2011	2012
CH_4	2,338,490	2,167,534	2,573,284	2,901,421	3,044,116
CH_4–CO_2e	58,462,253	54,188,354	64,332,090	72,535,514	76,102,912
CO_2	11,768	10,907	12,949	14,600	15,318

Tables A.15 and A.16 present the corresponding low and high scenarios for CH_4 and CO_2 emissions for downstream emissions, respectively, for natural gas produced conventionally from public lands.

Table A.15. CH_4 and CO_2 emissions associated with natural gas production from public lands: Conventional gas, downstream, low scenario (0.07% CH_4 leakage)

Emissions (metric tons)	2008	2009	2010	2011	2012
CH_4	21,334	15,800	15,882	12,505	11,511
CH_4–CO_2e	533,347	394,997	397,053	312,632	287,771
CO_2	107	80	80	63	58

Table A.16. CH_4 and CO_2 emissions associated with natural gas production from public lands: Conventional gas, downstream, high scenario (10.0% CH_4 leakage)

Emissions (metric tons)	2008	2009	2010	2011	2012
CH_4	3,097,458	2,293,979	2,305,918	1,815,634	1,671,255
CH_4–CO_2e	77,436,459	57,349,482	57,647,939	45,390,845	41,781,378
CO_2	15,587	11,544	11,604	9,136	8,410

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