

Comparing Life-Cycle Greenhouse Gas Emissions from Natural Gas and Coal



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Executive Summary

- **Research conclusion and key messages—natural gas offers greenhouse gas advantages over coal:** Natural gas has been widely discussed as a less carbon-intensive alternative to coal as a power sector fuel. In April 2011, the U.S. Environmental Protection Agency released revised methodologies for estimating fugitive methane emissions from natural gas systems. These revisions mostly affected the production component of the natural gas value chain (namely, gas well cleanups), causing a very substantial increase in the methane emissions estimate from U.S. natural gas systems.² This large increase in the upstream component of the natural gas value chain caused some to question the GHG advantage of gas versus coal over the entire life-cycle from source to use. As a result of this renewed attention, while it remains unambiguous that natural gas has a lower carbon content per unit of energy than coal does, several recent bottom-up studies have questioned whether natural gas retains its greenhouse gas advantage when the entire life cycles of both fuels are considered.³

Particular scrutiny has focused on shale formations, which are the United States' fastest growing marginal supply source of natural gas. Several recent bottom-up life-cycle studies have found the production of a unit of shale gas to be more GHG-intensive than that of conventional natural gas.⁴ Consequently, if the upstream emissions associated with shale gas production are not mitigated, a growing share of shale gas would increase the average life-cycle greenhouse gas footprint of the total U.S. natural gas supply.

Applying the latest emission factors from the EPA's 2011 upward revisions, our top-down life-cycle analysis

¹ EPA, *Inventory of U.S. Greenhouse Gas Emissions And Sinks:1990 – 2009*, U.S. EPA, EPA 430-R-11-005, http://www.epa.gov/climatechange/emissions/downloads11/US-GHG-Inventory-2011-Complete_Report.pdf, cited in Mark Fulton, et al., "Comparing Life Cycle Greenhouse Gas Emissions from Natural Gas and Coal," 14 March 2011, available at http://www.dbcca.com/dbcca/EN/media/Comparing_Life_Cycle_Greenhouse_Gas.pdf.

² Note: For example, the EPA's estimates of methane emissions from U.S. natural gas systems in the base year of 2008 increased 120 percent between the 2010 and 2011 versions of their *Inventory of U.S. Greenhouse Gas Emissions and Sinks*.

³ The two approaches for an LCA study are bottom-up and top-down. A bottom-up study analyzes the emissions from an individual representative or prototype process or facility and calculates the emissions of that specific part of the value chain. It then combines each step of the value chain to compute the total lifecycle emissions from source to use. A top-down study, in contrast, looks at the total national emissions for a particular use or sector and depicts the national average life-cycle emissions for each discrete part of source to use for that sector to arrive at an aggregate estimate. Each approach has benefits and limitations. The bottom-up approach provides insights into the emissions for a particular process or fuel source, but also depicts only that specific process or source. The top-down approach represents the emissions across an entire sector but does not focus on specific processes or technologies. Some of the data sources for a top-down analysis may be built up from bottom-up sources, but the top-down analysis still yields a more general result.

⁴ Robert W. Howarth, et al., "Methane and the greenhouse-gas footprint of natural gas from shale formations," *Climatic Change* (2011); Timothy J. Skone, National Energy Technology Laboratory (NETL), "Life Cycle Greenhouse Gas Analysis of Natural Gas Extraction & Delivery in the United States," presentation (Ithaca, NY: 12 May 2011; revised 23 May 2011); Mohan Jiang, et al., "Life cycle greenhouse gas emissions of Marcellus Shale gas," *Environmental Research Letters* 6 (3), 5 August 2011.



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(LCA)⁵ finds that the EPA's new methodology increases the life-cycle emissions estimate of natural gas-fired electricity for the baseline year of 2008 by about 11 percent compared with its 2010 methodology. But even with these adjustments, we conclude that **on average, U.S. natural gas-fired electricity generation still emitted 47 percent less GHGs than coal from source to use using the IPCC's 100-year global warming potential for methane of 25.** This figure is consistent with the findings of all but one of the recent life-cycle analyses that we reviewed.

While our LCA finds that the EPA's updated estimates of methane emissions from natural gas systems do not undercut the greenhouse gas advantage of natural gas over coal, methane is nevertheless of concern as a GHG, and requires further attention. In its recent report on improving the safety of hydraulic fracturing, the U.S. Secretary of Energy's Advisory Board's Subcommittee on Shale Gas Production recommended that immediate efforts be launched to gather improved methane emissions data from shale gas operations.⁶ In the meantime, methane emissions during the production, processing, transport, storage, and distribution of all forms of natural gas can be mitigated immediately using a range of existing technologies and best practices, many of which have payback times of three years or less.⁷ Such capture potential presents a commercial and investment opportunity that would further improve the life-cycle GHG footprint of natural gas. Although the adoption of these practices has been largely voluntary to date, the EPA proposed new air quality rules in July 2011 that would require the industry to mitigate many of the methane emissions associated with natural gas development, and in particular with shale gas development.⁸

Our research methodology: This paper seeks to assess the current state of knowledge about the average greenhouse gas footprints of average coal and natural gas-fired electricity in the system today, how the growing share of natural gas production from shale formations could change this greenhouse gas footprint at the margin, and what the findings imply for policymakers, investors and the environment. In the first part of the paper, we examine recent bottom-up life-cycle analyses to provide context for our top-down analysis. These bottom-up analyses' estimation of the life-cycle GHG footprint of shale gas provides information about the potential marginal GHG impact of shale's rising share in the U.S. natural gas supply, as well as which emissions streams can be targeted for the greatest GHG mitigation. In the second part of the paper, we conduct our own top-down life-cycle analysis of GHGs from natural-gas and coal-fired electricity in 2008 using the EPA's revised 2011 estimates as well as other publically available government data. We make three key adjustments to the data sets in order to calculate a more accurate and meaningful national level inventory: we include: 1) emissions associated with net natural gas and coal imports; 2) natural gas produced as a byproduct of petroleum production, and 3) the share of natural gas that passes through distribution pipelines before reaching power plants. This top-down analysis examines the implications of the EPA's revised (2011) estimates for the current and future average greenhouse gas footprint of U.S. natural gas-fired electricity and its comparison with coal-fired electricity.

GWP and power plant efficiency matter: Global warming potentials (GWPs) are used to convert the volumes of greenhouse gases with different heat-trapping properties into units of carbon dioxide-equivalent (CO₂e) for the purpose of examining the relative climate forcing impacts of different volumes of gas over discrete time periods. The Intergovernmental Panel on Climate Change's (IPCC) most recent assessment, published in 2007, estimates methane's GWP to be 25 times greater than that of carbon dioxide over a 100-year timeframe and 72 times greater than that of carbon dioxide over a 20-year timeframe.⁹ Unless

⁵ "Life-cycle analysis" (LCA) is a generic term, and the methodology and scope of analysis can vary significantly across studies. Our analysis assesses GHGs during the production, processing, transport, and use of natural gas and coal to generate electricity. Some studies include not only the direct and indirect emissions from the plant or factory that provides or makes a certain product, but also the emissions associated with the inputs used to manufacture and create the production facilities themselves. This study does not address the manufacturing, construction, or decommissioning of the equipment used in energy production. As with any study, the certainty of conclusions drawn from an LCA can only be as strong as the underlying data.

⁶ U.S. Department of Energy, Secretary of Energy Advisory Board, Shale Gas Production Subcommittee, 90-Day Report, 18 August 2011, http://www.shalegas.energy.gov/resources/081811_90_day_report_final.pdf.

⁷ Numerous technologies and best practices to capture methane that would otherwise be vented during natural gas production, processing, transport, or distribution have been detailed by the U.S. EPA's voluntary Natural Gas STAR Program. Many of these have payback periods under 3 years. U.S. Environmental Protection Agency, Natural Gas STAR Program, "Recommended Technologies and Practices," available at <http://www.epa.gov/gasstar/tools/recommended.html>, viewed 29 July 2011.

⁸ EPA, "Oil and Natural Gas Air Pollution Standards," <http://epa.gov/airquality/oilandgas/>, viewed 18 August 2011.

⁹ Piers Forster et al., 2007: Changes in Atmospheric Constituents and in Radiative Forcing. In: *Climate Change 2007: The Physical Science Basis. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change* [Solomon, S., D.

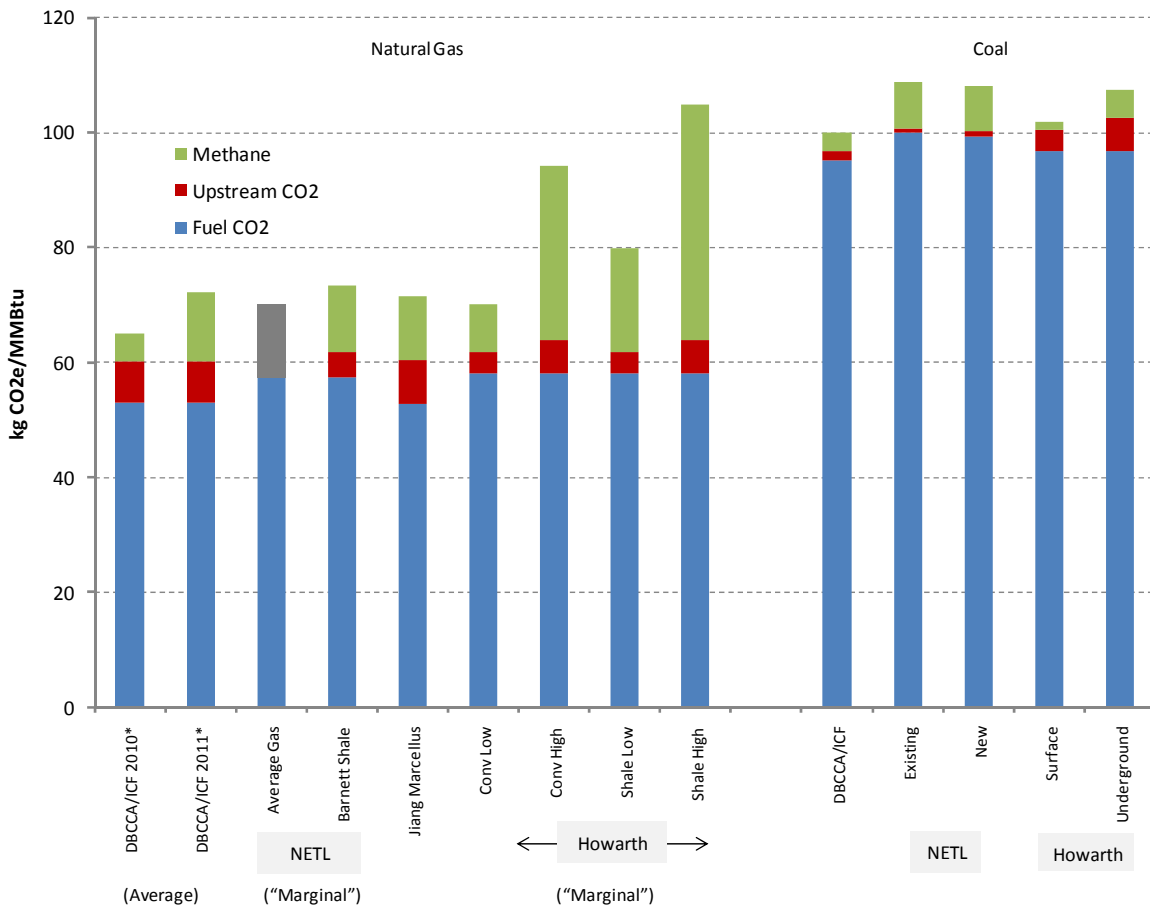


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otherwise specified, our analysis uses the 100-year GWP of 25 but we also calculate life-cycle emissions using a range of methane GWPs that have been proposed—including 72 and 105—in Appendix B of this report in order to show the sensitivities of the outputs to GWP. The choice of GWP does impact the relative GHG footprint between coal and gas. However, the life-cycle GHG footprint of gas is lower than coal under all GWPs tested, with the smallest difference calculated using a GWP of 105, where the GHG emissions in kilograms CO₂ per megawatt-hour of electricity generated (kg CO₂e/MWh) are 27 percent less than those of coal-fired generation.

In addition, assumed power plant efficiencies also have a measurable impact on the life-cycle comparison between natural gas and coal-fired electricity generation. Unless otherwise specified, our analysis uses average U.S. heat rates for coal and natural gas plants for the existing capital stock: 11,044 Btu/kWh (31% efficiency) for coal and 8,044 Btu/kWh (41% efficiency) for natural gas plants. We also calculate life-cycle emissions using heat rate estimates for new U.S. natural gas and coal plants in Appendix A (Exhibit A-11).

ES-1. Comparison of Recent Life-Cycle Assessments



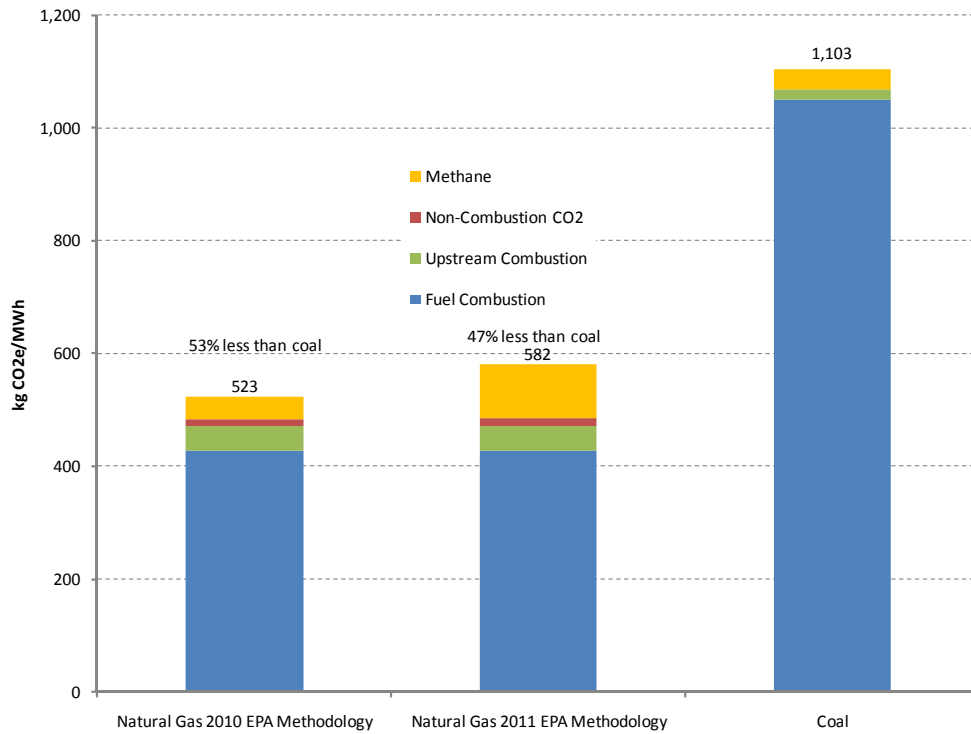
Source: DBCCA Analysis 2011; NETL 2011; Jiang 2011; Howarth 2011. Note: NETL Average Gas study includes bar shaded grey due to inability to segregate upstream CO₂ and methane values, which were both accounted for in the study. See page 10 for more information. *2011 EPA methodology compared to 2010.

Qin, M. Manning, Z. Chen, M. Marquis, K.B. Averyt, M. Tignor and H.L. Miller (eds.]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA., p. 212.



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**ES-2. Average U.S. Life-Cycle GHG Emissions from Coal and Gas Electricity Generation, 2008
Comparing EPA 2010 Methodology with EPA 2011 Methodology**



Source: DBCCA Analysis 2011. See pages 19 and 20 for more details.



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Introduction and Key Exhibits

- **Our methodology:** Our top-down analysis addresses the emissions of three GHGs emitted during the production, processing, storage, transmission, distribution, and use of natural gas and coal in power plants:
 1. Carbon dioxide (CO₂);
 2. Methane (CH₄) and;
 3. Nitrous oxide (N₂O)

Carbon dioxide is a product of fossil fuel combustion and is also released during some stages of gas processing. Methane, the primary component of natural gas (roughly 98 percent of pipeline-quality gas), is a potent GHG.¹⁰ It is released at many points during the life-cycle of natural gas production and use and also during coal mining, and it is an important component of the life-cycle emissions of both fuels, but especially of natural gas. Methane emissions can be categorized as “fugitive” or “vented” emissions. Fugitive emissions include unintentional “leaks” from poorly sealed valves, flanges, meters, and other equipment.¹¹ Venting is the intentional release of methane as part of the operating procedure for a particular process. For example, when a compressor or a pipeline is taken out of service for repair, the compressed gas in the equipment may be released. There are a variety of venting operations associated with natural gas production that account for the majority of methane emissions in the natural gas sector. Because the amount of fugitive and vented methane is highly dependent on the practices and technologies that are used, the amount of methane emitted can vary significantly by facility and/or the stripping and “clean up” process employed. Although small amounts of methane and nitrous oxide are also emitted during fossil fuel combustion, carbon dioxide is by far the largest greenhouse gas product. In this paper, because the amounts of methane and nitrous oxide are such a small fraction of the total combustion-related emissions, we include them together with CO₂ on tables and figures under the heading “combustion.”¹²

- **Reader roadmap:** In the section that follows, we start with a review of recent LCA studies. These studies have attempted to measure the life-cycle GHG footprint of shale gas and are valuable from our perspective in framing the marginal impact of shale gas on the GHG intensity of average natural gas-fired electricity. We then build up to a full comparison of the life-cycle emissions between natural gas and coal-fired electricity generation at a national level based on different assumptions and data adjustments in order to assess the impact that the EPA 2011 methodology change on GHG inventory has on the LCA comparison between average U.S. natural gas- and coal-fired electricity generation. We use emissions data for 2008 as a comparable baseline to show the impact of the 2010 and 2011 changes in EPA methane methodology to the life-cycle GHG emissions comparison between coal and natural gas in that year. (Note the Global Warming Potential used throughout this analysis is 25 unless otherwise noted – see Appendix B.) This overview provides a roadmap to follow the logic of our analytic approach.
 - **Step 1:** In Exhibit 2, page 10 we compare the most recent bottom-up studies of the LCA of gas from hydraulically fractured shale formations versus coal as a starting point;
 - **Step 2:** In Exhibit 4, page 13 we list the baseline EPA data for 2008 on the upstream natural gas emissions expressed as million metric tons of CO₂ equivalent (MMTCO_{2e});

¹⁰ Methane remains in the atmosphere for ~9-15 years, compared to 100+ years for CO₂; Methane, however, is much more effective at trapping heat in the atmosphere than CO₂, particularly over 20 year time periods (Please see Appendix B at the end of this report).

¹¹ Of critical importance, such leaks can be fairly easily mitigated from a technical perspective at reasonable cost, which means that there is scope for improvement.

¹² The EPA Greenhouse Gas Reporting Rule gives CH₄ and N₂O emission factors for the combustion of different fossil fuels. For CH₄, emission factors of 0.001 kg/MMBtu of natural gas and 0.011 kg/MMBtu of coal were used. For N₂O, emission factors of 0.0001 kg/MMBtu of natural gas and 0.0016 kg/MMBtu of coal were used. The emission factors are in table C-2, page 38 of Subpart C of the rule. (Please see: <http://www.epa.gov/climatechange/emissions/downloads09/GHG-MRR-FinalRule.pdf>)

These were then adjusted using GWPs for CH₄ and N₂O to obtain emissions factors in kg CO_{2e}/MMBtu. Unless otherwise noted in the paper, 100-year GWP values from the IPCC's Fourth Assessment Report (2007) were used: 25 for CH₄ and 298 for N₂O. Using these values, the total GHGs emitted during the combustion of natural gas are 53.07 kg CO_{2e}/MMBtu (99.90% CO₂, 0.05% CH₄, 0.06% N₂O) and the total GHGs emitted during the combustion of coal are 95.13 kg CO_{2e}/MMBtu (99.21% CO₂, 0.29% CH₄, 0.50% N₂O).



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- **Step 3:** In Exhibit 5, page 14, we adjust these baseline estimates to account for additional factors such as natural gas imports, methane emissions from other parts of the industry and other types of emissions associated with natural gas production;
- **Step 4:** In Exhibit 6, page 15, we combine our adjusted upstream and downstream natural gas emissions to derive a normalized life-cycle emissions expressed as kg/MMBTU (volume of greenhouse gases per unit of energy value delivered to the power plant) and compare with coal on an equivalent carbon-dioxide equivalent basis for the electricity sector using 2008 data and the EPA's 2011 methane emissions methodology;
- **Step 5:** In Exhibit 7, page 15, we rerun Step 3 above for 2008 emissions but using the EPA 2010 methane emission methodology from the EPA in order to show the impact of the revisions pre-combustion in kg CO₂e/MMBtu;
- **Step 6:** In Exhibit 8, page 15, we use EPA's 2011 methane emissions methodology to calculate emissions for 2009, the most recent year data available;
- **Step 7:** In Exhibit 10, page 17, we adjust upstream emissions from coal into standard volume units of MMTCO₂e in order to assess the emissions associated with the production and transportation from the mine to the power plant using 2008 data for an apples-to-apples comparison with gas;
- **Step 8:** In Exhibit 11, page 17, we then normalize these upstream coal emission factors into kg CO₂e/MMBtu (emission volume per unit of energy delivered);
- **Step 9:** In Exhibit 12, page 19, we compare the life-cycle emissions of natural gas and coal delivered to the power plant in kg CO₂e/MMMBtu using 2008 data but adjusted for both 2010 and 2011 EPA methane emission factor methodologies for natural-gas to show the impact of EPA's revisions;
- **Step 10:** In Exhibit 13, page 20, we show the LCA in terms of emissions per megawatt-hour of electricity generated from gas and coal using the national average power plant efficiencies for 2008. The life-cycle emissions for gas are 11 percent higher using the updated methodology. The Exhibit shows a six percentage point change with gas producing 47 percent lower emissions than coal using EPA's 2011 methane methodology compared to producing 53 percent lower emissions using EPA 2010 methane methodology based on a 100-year GWP value for methane of 25.
- **Sensitivity Analysis Using Alternative GWPs:** In Appendix B, we show the sensitivities of our LCA to different GWPs.



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Overview of Natural Gas Systems and Emission Sources

Between its 2010 and 2011 editions of the Inventory, the EPA significantly revised its methodology for estimating GHG emissions from natural gas systems, resulting in an estimate of methane emissions from Natural Gas Systems in 2008 that was 120 percent higher than its previous estimate. Up until 2010, the Inventory had relied extensively upon emission and activity factors developed in a study by the EPA and the Gas Research Institute in 1996. For the 2011 Inventory, the EPA modified its treatment of two emissions sources that had not been widely used at the time of the 1996 study, but have since become common: gas well completions and workovers with hydraulic fracturing. It also significantly modified the estimation methodology for emissions from gas well cleanups, condensate storage tanks, and centrifugal compressors.

The bulk of the EPA's recent upward revisions of natural gas emissions estimates are related to the production part of the gas value chain. The largest component of the increase is due to revised estimates of methane released from liquids unloading: In some natural gas wells, downhole gas pressure is used to blow reservoir liquids that have accumulated at the bottom of the well to the surface.¹³ The revisions also include an increase in the share of gas that is produced from hydraulically fractured shale gas wells and a change in the assumption as to how much of the flow-back emissions are flared. Previously, the EPA assumed that 100 percent of these emissions were flared or captured for sale. The new estimate assumes that approximately one third are flared and another third are captured through "reduced emission completions." Both of these are based on estimated counts of equipment and facility and associated emission factors.

These revisions have caused some to question whether replacing coal with natural gas would actually reduce GHGs, when emissions over the entire life cycles of both fuels are taken into account. Addressing these questions requires an understanding of:

- 1) The best available data on emissions throughout the life cycles of natural gas and coal;
- 2) The specific sources and magnitudes of GHG emissions streams for natural gas produced from shale versus conventional formations; and
- 3) How an increase in the contribution of shale gas to the U.S. natural gas supply might impact the overall life-cycle GHG footprint of natural gas-fired electricity in the future as the marginal skews the average.

Up until the past few years, most of the U.S. natural gas supply came from the Gulf of Mexico and from western and southwestern states. More recently, mid-continental shale plays have been a growing source of supply. Natural gas is produced along with oil in most oil wells (as "associated gas") and also in gas wells that do not produce oil (as "non-associated gas").

Exhibit 1 illustrates the primary sources of GHG emissions during natural gas production, processing, transmission and distribution. The equipment for drilling both oil and gas wells is powered primarily by large diesel engines and also includes a variety of diesel-fueled mobile equipment. Raw natural gas is vented at various points during production and processing prior to compression and transport by pipeline. In some cases, the gas may be flared rather than vented to maintain safety and to relieve over-pressuring within different parts of the gas extraction and delivery system. Flaring produces CO₂, a less potent GHG than methane.

¹³ The technique of blowing out liquids is most frequently used in vertical wells containing "wet" or liquids-rich gas. It is being replaced by many producers with "plunger lifts" that remove liquids with much less gas release. In many shale wells, a technique is used where liquids are allowed to collect in a side section of the well and removed with a pump. EPA, Natural Gas Star, "Lessons Learned: Installing Plunger Lift Systems in Gas Wells," October 2006, available at http://www.epa.gov/gasstar/documents/ll_plungerlift.pdf.

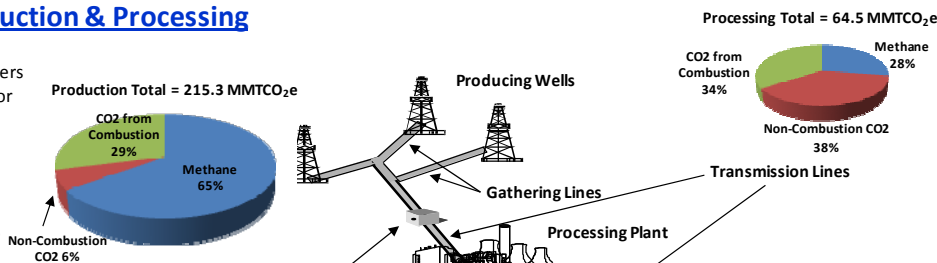


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Exhibit 1. Natural Gas Industry Processes and Methane Emission Sources

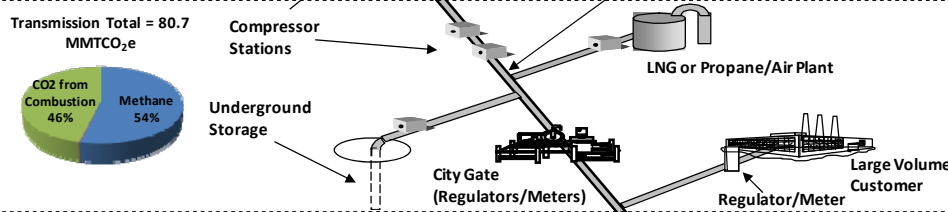
Natural Gas Production & Processing

- Well completions, blowdowns, and workovers
- Reciprocating compressor rod packing
- Processing plant leaks
- Gas-driven pneumatic devices
- Venting from glycol reboilers on dehydrators



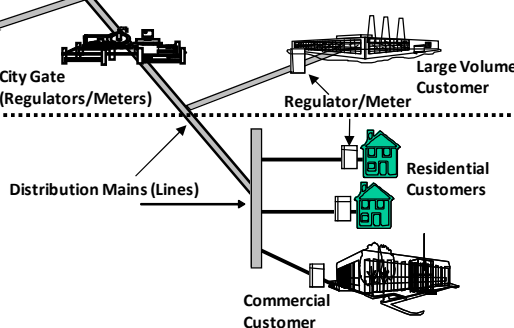
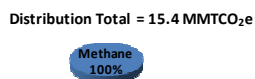
Gas Transmission

- Venting of gas for maintenance or repair of pipelines or compressors
- Centrifugal compressor seal oil de-gassing
- Leaks from pipelines, compressor stations



Gas Distribution

- Leaks from unprotected steel mains and service lines
- Leaks at metering and regulating stations
- Pipeline blowdowns



Sources: American Gas Association; EPA Natural Gas STAR Program, DBCCA analysis, 2011.

The recent focus of new natural gas development has been shale gas, which currently represents about 14 percent of U.S. domestic production but is expected to reach 45 percent or more by 2035.¹⁴ Most gas-bearing shale formations lie 8,000 to 12,000 feet below the surface and are tapped by drilling down from the surface and then horizontally through the target formation, with lateral drills extending anywhere from 3,000 to 10,000 feet. After drilling is complete, operators hydraulically fracture the shale, pumping fluids at high pressure into the well to stimulate the production of the gas trapped in the target rock formation. Horizontal drilling and pumping water for hydraulic fracturing release additional engine emissions compared to conventional production techniques. In addition, when the produced water “flows back” out of the well, raw gas from the producing formation can be released into the atmosphere at the wellhead.¹⁵

In both associated and non-associated gas production, water and hydrocarbon liquids are separated from the gas stream after it is produced at the wellhead. The gas separation process may involve some fuel combustion and can also involve some venting and/or flaring. Shale plays in particular are geologically heterogeneous, and the energy requirements to extract gas can vary widely. Moreover, the methane content of raw gas varies widely among different gas formations. Although some gas is pure enough to be used as-is, most gas is first transported by pipeline from the wellhead to a gas processing plant. Gas processing plants remove additional hydrocarbon liquids such as ethane and butane as well as gaseous impurities from the raw gas, including CO₂, in order for the gas to be pipeline-quality and ready to be compressed and transported. This “formation” CO₂ is vented at the gas processing plant and represents another source of GHG emissions along with the combustion emissions from the plant’s processing equipment.

From the gas processing plant, natural gas is transported, generally over long distances by interstate pipeline to the “city gate” hub and then to the power plant. The vast majority of the compressors that pressurize the pipeline to move

¹⁴ EIA Annual Energy Outlook 2011. DOE/EIA-0383ER(2011). Energy Information Administration, U.S. Department of Energy. [http://www.eia.gov/forecasts/aeo/pdf/0383\(2011\).pdf](http://www.eia.gov/forecasts/aeo/pdf/0383(2011).pdf)

¹⁵ The GHG comparison between conventional and shale wells is important given the rapidly evolving industrial landscape with a share shift toward shale wells. For its part, the International Energy Agency (IEA) in a June 2011 Special Report: “Are We Entering a Global Age of Gas?” concluded that the LCA emissions of natural gas from shale wells is between 3.5 and 12 percent more than from conventional gas. IEA, June 2011, page 64.



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the gas are fueled by natural gas, although a small share is powered by electricity.¹⁶ Compressors emit CO₂ emissions during fuel combustion and are also a source of fugitive and vented methane emissions through leaks in compressor seals, valves, and connections and through venting that occurs during operations and maintenance. Compressor stations constitute the primary source of vented methane emissions in natural gas transmission. Actual leakage from the pipelines themselves is very small.

Some power plants receive gas directly from transmission pipelines, while others have gas delivered through smaller distribution pipelines operated by local gas distribution companies (LDCs). Distribution lines do not typically require gas compression; however, some relatively small methane emissions do occur due to leakage from older distribution lines and valves, connections, and metering equipment.

Review of Recent Bottom-Up Life-Cycle Analyses: The Marginal Impact on Emissions

The assessment of how much more methane is released from shale gas production than from conventional production is a key factor in the discussion of possible changes in the life-cycle emissions of natural gas. As the shale gas component of U.S. production increases, a higher marginal greenhouse gas footprint from shale gas would raise the average greenhouse gas footprint of the U.S. natural gas supply overall. On the other hand, changing production technology and regulation could reduce emissions from both shale and other natural gas wells. The life-cycle GHG comparison between shale and conventional natural gas therefore has important implications for stakeholders who are considering policies and investment on the basis of how carbon-intensive natural gas is today and how carbon-intensive it is likely to be in the future.

A number of recent bottom-up life-cycle analyses attempt to quantify the GHG comparison between conventional and shale gas. Exhibit 2 shows the results of several of these analyses and how they compare to our top down analysis, which follows later.¹⁷ Bottom-up figures are taken from studies by Skone, et al. (NETL), Jiang et al. (Jiang), and Howarth, et al. (Howarth). Because these and other life-cycle studies each make different assumptions as to the global warming potential of methane and the product whose greenhouse gas footprint is being measured—some use units of natural gas produced, others use units of natural gas delivered, and still other use units of electricity generated—we have normalized these figures using a GWP of 25. Any remaining variability in the GHG estimates are the result of differences in underlying emissions factors used. Despite differences in methodology and coverage, all of the recent studies except Howarth et al. estimate that life-cycle emissions from natural gas-fired generation are significantly less than those from coal-fired generation on a per MMBtu basis. As can be seen in Exhibit 2, our GHG estimate for average U.S. gas based on EPA's 2011 data (72.3 kg/MMBtu) is very similar to the National Energy Technology Laboratory's (NETL) bottom-up estimate for Barnett Shale gas (73.5 kg/MMBtu).

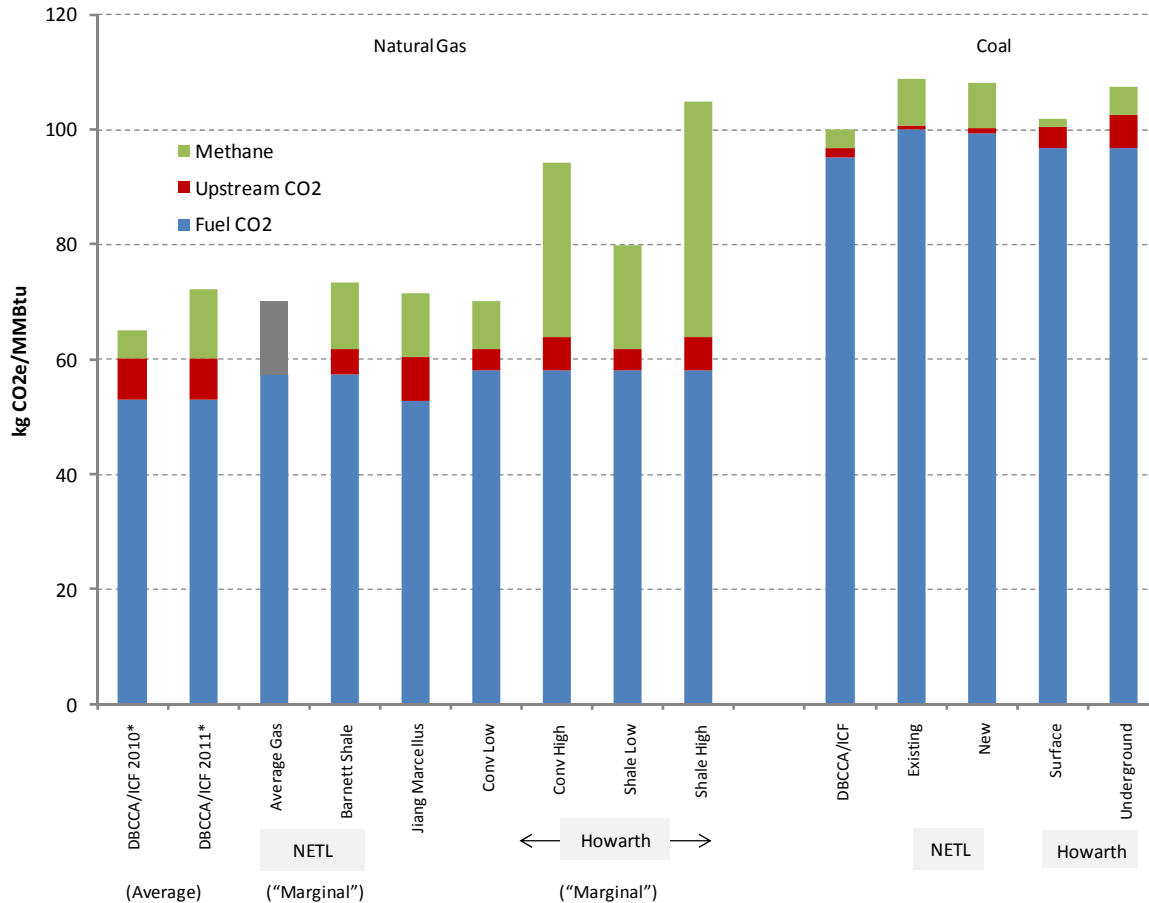
¹⁶ ORNL, *Transportation Energy Data Book*, Oak Ridge National Laboratory, U.S. Department of Energy, June 2010, <http://cta.ornl.gov/data/index.shtml>

¹⁷ The results of the top-down life-cycle analysis conducted in the present study are displayed for reference. Bottom-up figures are taken from studies by Skone, et al. 2011 (NETL), Jiang et al. 2011 (Jiang), and Howarth, et al. 2011 (Howarth). All studies are normalized using a 100-year GWP for methane of 25, and given in kg CO₂e per MMBtu of fuel rather than kg CO₂e per MWh of electricity generated. Most studies use MMBtu of fuel produced as their metric; the present study uses MMBtu of fuel consumed, an explanation of which is given on p. 22. .



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Exhibit 2. Comparison of Recent Bottom-Up Life-Cycle Assessments.



Source: DBCCA Analysis, 2011. Note: NETL Average Gas study includes bar shaded grey due to inability to segregate upstream CO2 and methane values, which were both accounted for in the study. *2011 EPA methodology compared to 2010.

Many of these studies draw upon data from the U.S. Environmental Protection Agency's *Inventory of U.S. Greenhouse Gas Emissions and Sinks* (hereafter "Inventory" or "Greenhouse Gas Inventory"). The Inventory, published annually, is the official U.S. report on GHG emissions to the UN IPCC and the source for much of the analysis of U.S. emissions.¹⁸ The inventory is developed from a variety of public and private data sources on the many different kinds of GHG emission sources in different sectors. It uses a combination of "bottom-up" analysis, utilizing counts and characteristics of individual facilities, and "top-down" analysis, such as national data on fuel combustion from the Energy Information Administration (EIA) to calculate CO₂ emissions from combustion, to build an estimate for total U.S. GHG annual emissions across a range of sectors.

Greenhouse gas emissions from natural gas and coal production, processing, transport, and distribution are estimated in the Inventory's "Natural Gas Systems" and "Coal Mining." In the EPA's 2011 edition of the Inventory, Natural Gas Systems were estimated to be the largest source of non-combustion, energy-related GHG emissions in the U.S., at 296 million metric tons of CO₂ equivalent (MMT CO₂e) in 2009. Coal mining came in third, with an estimated 85 MMT CO₂e of emissions. Fossil fuel combustion accounted for the vast majority of GHG emissions from the U.S. energy sector, with an estimated 1,747.6 MMT CO₂e coming from coal-fired electricity generation alone, while natural gas-fired electricity generation accounted for an additional 373.1 MMT CO₂e (Exhibit 3).¹⁹

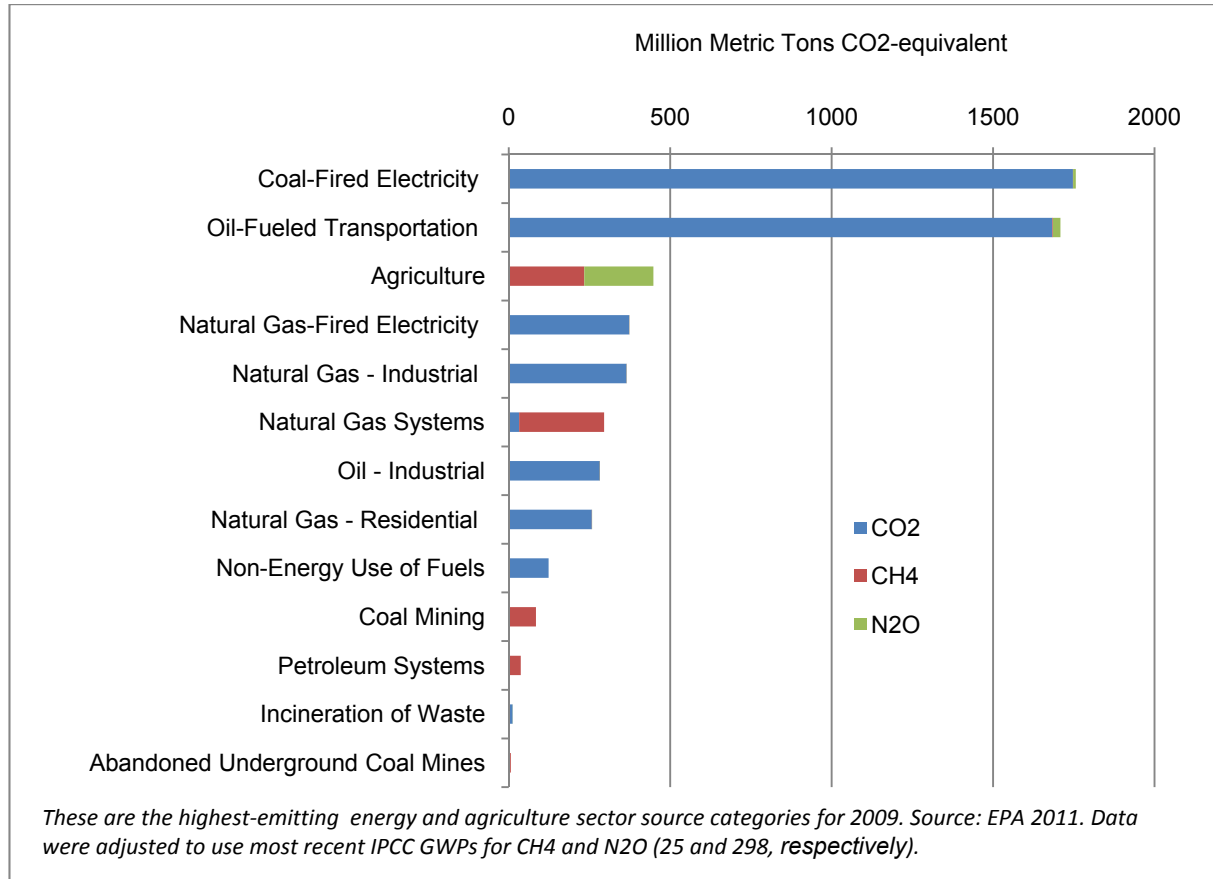
¹⁸ EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009* (April 2011), available at <http://epa.gov/climatechange/emissions/usinventoryreport.html>.

¹⁹ All figures given in CO₂-equivalent here and elsewhere assume a global warming potential of 25 for methane unless otherwise noted. The EPA's Inventory uses a GWP of 21 for reporting purposes, so these numbers were converted to make them consistent with the GWP used for



Comparing Life Cycle Greenhouse Gas Emissions from Natural Gas and Coal

Exhibit 3. U.S. Greenhouse Gas Emissions by Source Category, 2009.



We draw two main conclusions from our survey of recent bottom-up life-cycle assessments. First, **the natural gas industry's practices are evolving rapidly, and better data are essential to ensuring that life-cycle greenhouse gas assessments remain up-to-date and reflect current industry behavior.** All of the bottom-up life-cycle assessments we surveyed identified significant uncertainty around certain segments of the natural gas life cycle stemming from data inadequacy. Among the sources of uncertainty identified were: formation-specific production rates, flaring rates during extraction and processing, construction emissions, transport distance, penetration and effectiveness of green completions and workovers, and formation-specific gas compositions.

Second, because shale gas appears to have a GHG footprint some 8 to 11 percent higher than conventional gas on a life-cycle basis per mmBtu based on these bottom up studies that we reviewed, **increased production of shale gas would tend to increase the average life-cycle GHG footprint from U.S. natural gas production if methane emissions from the upstream portion of the natural gas life are unmitigated.** This fact underlines the **importance of implementing the many existing control technologies and practices that can significantly reduce the overall greenhouse gas footprint of the natural gas industry.** Many companies are already reducing vented and flared methane emissions voluntarily through the EPA's voluntary Natural Gas STAR program. For example, the Inventory estimates that the completion emissions of methane from two thirds of shale gas production are already being mitigated through flaring or reduced emission completion.²⁰ If this is correct, then bottom-up life-cycle GHG estimates that do not account for reduced emissions completions are likely too high.

the main analysis in this paper. EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009* (April 2011), available at <http://epa.gov/climatechange/emissions/usinventoryreport.html>.

²⁰ *Ibid.*



Comparing Life Cycle Greenhouse Gas Emissions from Natural Gas and Coal

Stronger regulations limiting methane and other air pollutant emissions from oil and natural gas operations are also likely to lead to lower overall GHG emissions. Some states already require the adoption of certain methane controls: Wyoming and Colorado, for example, already require “no-flare” or “green” completions and workovers, which are reported to capture 70 to 90 percent of methane vented during completions and workovers following hydraulic fracturing. Because this methane can then be sold, users of green completions have reported payback times of less than one year.²¹ Moreover, the EPA released proposed regulations for the gas production sector on July 28, 2011 that are expected to require mitigation of completion emissions from all wells.²² This regulation is currently in the comment period and is set to be implemented by court order in 1Q12. If these regulations are adopted, there will be little or no difference between the emissions of hydraulically fractured and conventional gas wells.

Top-Down Life-Cycle Analysis of U.S. Natural Gas and Coal: Impact on the Average

The remainder of this paper develops a top-down life-cycle greenhouse gas analysis of natural gas and coal for the purpose of determining the impact of recent EPA revisions to methane emissions estimation methodologies on the current comparison between U.S. natural gas and coal-fired electricity.

Natural Gas

This analysis for natural gas includes each of the industry steps described in Exhibit 1 above. (See Appendix A for a detailed methodology.) The source of information for methane emissions and non-combustion CO₂ is the EPA’s *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2009* (April 2011 release), which includes updated estimates for methane emissions from natural gas production that are approximately twice the level indicated in the previous 2010 edition.²³ This LCA uses the data from both 2010 and 2011 EPA inventory reports to illustrate the effect that the EPA’s latest increase in estimated methane emissions has on the overall LCA for gas (as discussed below), which we estimate to be about an 11 percent increase in the life-cycle emissions.

The U.S. Energy Information Administration (EIA) is the primary source for the data on natural gas consumption and associated CO₂ emissions in the various segments of the gas industry (fuel for gas compressors and gas processing plants).²⁴ In addition to the natural gas, petroleum is used for drill rigs, trucks and other mobile equipment, such as pumps for hydraulic fracturing. This analysis uses information from the Economic Census to estimate non-natural gas energy consumption and associated CO₂ emissions in the production sector.²⁵

Sources of methane emissions are many and vary widely. Apart from EIA there are very few sources of aggregated data in the public domain. As noted earlier, the EPA recently increased its estimates significantly for several processes in natural gas production, and better data availability on methane leakage and venting will be critical going forward given the rapidly evolving gas production landscape. On this score, disclosures and reporting of upstream emissions have historically been voluntary. And while there is evidence that large volumes of GHGs are being captured by industry, the actual penetration rates of these voluntary programs is unknown²⁶.

For example, the EPA Natural Gas STAR program, a voluntary methane mitigation program, reports that its members reduced methane emissions from natural gas systems by 904 billion cubic feet between 2003 and 2009—equivalent to 365 MMTCO₂e.²⁷ This program has identified and documented many methane mitigation measures that could be applied more widely across both industries and are included in the EPA’s Inventory of US Greenhouse Gas Emissions

²¹ EPA, Natural Gas STAR Program, “Reduced Emissions Completions: Lessons Learned,” available at http://www.epa.gov/gasstar/documents/reduced_emissions_completions.pdf, viewed 2 August 2011.

²² EPA, “Oil and Natural Gas Air Pollution Standards,” <http://epa.gov/airquality/oilandgas/>, viewed 18 August 2011.

²³ The new EPA data have raised questions on two ends, with some believing the estimates are too high and others believing they are too low. Some comments submitted to the EPA from gas producers about the Draft Inventory question the validity of these revisions, believing them too high. While on the other hand, there are environmental advocacy groups that question whether EPA’s “activity factors” used in its methodology accurately represent the preponderance of shale wells being drilled in the Gulf Coast and North East regions, thereby raising the question of whether the emission factors are indeed high enough.

²⁴ EIA, Natural gas navigator. Natural gas gross withdrawals and production. http://www.eia.gov/dnav/ng/ng_prod_sum_dc_u_NUS_m.htm

²⁵ U.S. Department of Commerce, Census of Mining 2007, Census Bureau, U.S. Department of Census

²⁶ Reported 2009 Natural Gas STAR voluntary emission reductions were the equivalent of ~\$344 million in revenue (assuming \$4/mmBtu gas) and the avoidance of 34.8 mn tonnes CO₂e; <http://www.epa.gov/gasstar/accomplishments/index.html#content>

²⁷ EPA Natural Gas STAR Program Accomplishments, page 2; <http://www.epa.gov/gasstar/accomplishments/index.html>



Comparing Life Cycle Greenhouse Gas Emissions from Natural Gas and Coal

and Sinks report.²⁸ Additionally, many mitigation activities are not reported to these programs. It is also possible that the EPA is missing or has underestimated some sources of upstream emissions for both natural gas and coal. Nevertheless, we expect that better information will be available in the spring of 2012 when reporting of data on upstream methane emissions through EPA's GHG Reporting Program commences.

In our LCA, the emission factors for the combustion of natural gas, coal and petroleum includes the CO₂ from complete combustion of the fuel plus the small amounts of nitrous oxide (N₂O) and unburned methane that result from the combustion. The emission factors for fuel combustion are taken from subpart C of the EPA Greenhouse Gas Reporting Program.²⁹ The N₂O and methane emissions from combustion are less than 1% of the CO₂ emissions. The total emission factors for combustion are:

- Natural gas – 53.07 kg CO₂ e/MMBtu
- Diesel fuel – 74.21 kg CO₂ e/MMBtu
- Coal – 95.11 kg CO₂ e/MMBtu

Exhibit 4 summarizes the data on total upstream GHG emissions calculated for the natural gas sector for the year 2008 using the April 2011 EPA inventory for methane adjusted for a methane GWP of 25 and the EIA data on fuel consumption. According to this inventory, U.S. production, processing, and transport of natural gas emitted 387.0 million tons of CO₂ equivalent (MMTCO₂e) in 2008.

Exhibit 4. Baseline U.S. Upstream Gas Emission Data for 2008 (MMTCO₂e)

	Methane	Non-Combustion CO ₂	CO ₂ and N ₂ O from Combustion	Total
Production	146.3	11.3	47.2	204.8
Processing	18.7	21.4	19.4	59.5
Transmission	51.5	0.1	35.4	87.1
Distribution	35.6			35.6
Total	252.1	32.8	102.1	387.0

In this analysis, we adjust several factors to more accurately and robustly capture the life-cycle emissions associated with the use of natural gas on a national basis.

First, the emissions estimates account for natural gas production in the United States; however, because 13 percent of natural gas consumed in the U.S. was imported in 2008, we increase the production and processing emissions estimates to account for emissions from gas imports. Of that 13 percent in 2008, 11.7 percent was imported by pipeline from North America, mostly from Canada. The analysis assumes that other North American production operations are similar to those in the United States, so the emissions are increased linearly to account for these imports. In addition, 1.3 percent of the gas supply arrived via liquefied natural gas (LNG) imports. The LNG life cycle includes additional emissions associated with liquefaction, transportation, and regasification from source to use. The LNG portion is escalated by 76 percent to account for these emissions, based on a bottom-up LNG LCA prepared by NETL.³⁰ These are the most significant modifications made in our analysis, increasing the overall LCA for natural gas by 39 MMTCO₂e, or about 10 percent, primarily due to the adjustment for pipeline imports.

A second adjustment relates to methane emissions from distribution lines at local gas distribution companies. Since only 52 percent of the gas used for power generation is delivered by local distribution lines, the methane emissions associated with distribution have been discounted by that amount.³¹ This reduces the total emissions by 18 MMTCO₂e, or 4 percent.

²⁸ EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009, April 2011, available at http://www.epa.gov/climatechange/emissions/downloads11/US-GHG-Inventory-2011-Complete_Report.pdf, p. 152.

²⁹ EPA, Greenhouse Gas Reporting Program, Subpart C, U.S. Environmental Protection Agency, <http://www.epa.gov/climatechange/emissions/ghgrulemaking.html>

³⁰ Skone, T.J., 2010. Life Cycle Greenhouse Gas Analysis of Power Generation Options, National Energy Technology Laboratory, U.S. Department of Energy

³¹ EIA, EIA-176, "Annual Report of Natural and Supplemental Gas Supply and Disposition", Energy Information Administration, U.S. Department of Energy. http://www.eia.gov/cfapps/ngqs/nqqs.cfm?f_report=RP1&CFID=5251631&CFTOKEN=51c7f7f0104e329d-3FD56B17-237D-DA68-24412047FB2CE3CB



Comparing Life Cycle Greenhouse Gas Emissions from Natural Gas and Coal

A final adjustment is for methane emissions from production of associated gas—gas produced from oil wells. We did this in order to accurately adjust the impact of associated gas in our net import correction. Most oil wells produce some natural gas, and some of this gas is collected and becomes part of the gas supply. The EPA inventory of U.S. GHG emissions estimates that methane emissions from petroleum systems are approximately 30 MMTCO₂e per year.³² Since some domestic natural gas is co-produced with petroleum, these emissions could be considered for inclusion in the LCA of emissions from the natural gas sector.

The associated natural gas produced and the methane emitted during petroleum production, processing, and transport are a byproduct of petroleum production. Methane emissions would occur even if no natural gas were captured and delivered for end-use consumption. In fact, the emissions might actually be higher in that case since there would be no economic incentive to capture the gas. By this assessment it would not be appropriate to count the methane emissions from petroleum production, since they are independent of the production of gas.

On the other hand, associated gas produced from oil wells represents a significant segment of U.S. gross withdrawals of natural gas, and if there are methane emissions associated with that production, it seems appropriate to include them in the LCA, even if the production is incidental to oil production. In that case, we have to evaluate how much of the methane emissions to allocate to gas production versus petroleum production. This calculation is shown in Appendix A and results in an additional 5 MMTCO₂e of emissions being added, or a 1.4 percent increase.

Exhibit 5 shows our adjusted total emissions for 2008, which come to 423.8 MMTCO₂e compared to the 387.0 baseline. The production segment is the largest contributor to GHG emissions from the natural gas supply chain, accounting for 57 percent of total emissions. Of the different gases, methane accounts for 59 percent of total GHG emissions using a GWP of 25.

Exhibit 5. Adjusted Total Upstream GHG Emissions from Natural Gas, 2008 (MMTCO₂e)

	Methane	Non-Combustion CO ₂	CO ₂ and N ₂ O from Combustion	Total
Production	173.7	12.9	62.2	248.7
Processing	21.3	24.4	22.2	67.9
Transmission	51.5	0.1	37.2	88.8
Distribution	18.3	0.0	0.0	18.3
Total	264.9	37.4	121.5	423.8

To compare emissions from coal and natural gas on an apples-to-apples basis, the emissions are normalized to the amount of GHG per million Btu (MMBtu) of *natural gas delivered to consumers* using EIA data for gas deliveries³³. Some LCAs normalize to GHG per unit of natural gas *produced*, which includes associated gas that is reinjected into the producing formation as well as natural gas liquids that are removed during gas processing and gas lost through fugitives and venting, in addition to gas actually delivered to consumers such as power plants. Using delivered rather than produced natural gas results in a slightly higher overall figure for life-cycle emissions but depicts more accurately the energy that is actually available to power plants. The total normalized upstream emissions are 19.2 kg CO₂e/MMBtu of natural gas delivered. (See Exhibit 6.) As discussed earlier, the emissions for combustion of the natural gas at the power plant are 53.1 kg CO₂e/MMBtu, so the total life-cycle GHG emissions at the point of use are 72.3 kg/MMBtu. Of this, the upstream emissions are 30 percent, 60 percent of which are from methane.

³² *Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2009*, EPA 340-R-11-005, April 2011 page, 27

³³ EIA, *Natural gas navigator. Natural gas gross withdrawals and production*. http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_m.htm



Comparing Life Cycle Greenhouse Gas Emissions from Natural Gas and Coal

Exhibit 6. Normalized Life-Cycle GHG Emissions for Natural Gas for 2008, using EPA 2011 Methane Emissions Methodology (kg CO₂e/MMBtu)

	Methane	Non-Combustion CO ₂	CO ₂ and N ₂ O from Combustion	Total
Production	7.9	0.6	2.8	11.3
Processing	1.0	1.1	1.0	3.1
Transmission	2.3	0.0	1.7	4.0
Distribution	0.8	0.0	0.0	0.8
Total Upstream	12.0	1.7	5.5	19.2
Fuel Combustion	0	0	53.1	53.1
Total	12.0	1.7	58.6	72.3

Doing the same calculation with the lower methane emissions estimated in the prior year's EPA inventory yields a value of 12.0 kg CO₂e/MMBtu for the upstream emissions. (See Exhibit 7) Including the end-use gas consumption, total life-cycle emissions are 65.1 kg CO₂/MMBtu, with the upstream portion accounting for 20 percent. In this case, methane makes up only about 40 percent of the upstream gas GHG footprint.

Exhibit 7. Normalized Life-Cycle GHG Emissions for Natural Gas for 2008, using EPA 2010 Methane Emissions Methodology (kg CO₂e/MMBtu)

	Methane	Non-Combustion CO ₂	CO ₂ and N ₂ O from Combustion	Total
Production	1.2	0.4	2.8	4.4
Processing	0.8	1.1	1.0	2.9
Transmission	2.1	0.0	1.7	3.8
Distribution	0.8	0.0	0.0	0.8
Upstream Total	4.9	1.6	5.5	12.0
Fuel Combustion	0	0	53.1	53.1
Total	4.9	1.6	58.6	65.1

Finally, Exhibit 8 applies the most recent EPA data to calculate the life-cycle emissions for 2009 using the 2011 methane emissions methodology. This is the most recent year for which data are available. The 2009 emissions are quite similar to the emissions calculated for 2008 using the same methodology (73.1 vs 72.1 expressed as kg CO₂e/MMBtu).

Exhibit 8. Normalized Life-Cycle GHG Emissions for Natural Gas for 2009, using EPA 2011 Methane Emissions Methodology (kg CO₂e/MMBtu)

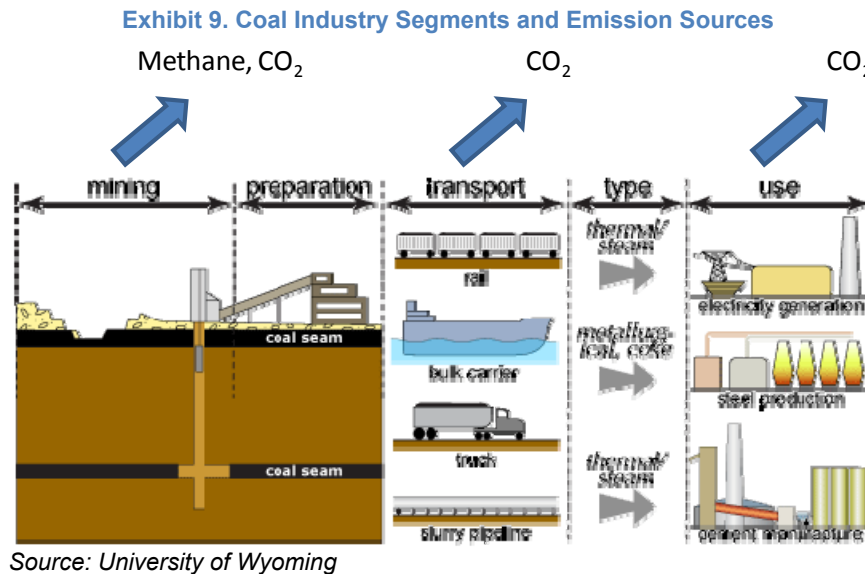
	Methane	Non-Combustion CO ₂	CO ₂ and N ₂ O from Combustion	Total
Production	8.4	0.6	3.0	12.0
Processing	1.1	1.1	1.0	3.2
Transmission	2.4	0.0	1.6	4.0
Distribution	0.8	0.0	0.0	0.8
Upstream Total	12.8	1.7	5.6	20.1
Fuel Combustion	0.0	0.0	53.1	53.1
Total	12.8	1.7	58.7	73.1



Comparing Life Cycle Greenhouse Gas Emissions from Natural Gas and Coal

Coal

The production and distribution of coal is simpler to analyze than that of natural gas because there are fewer steps in production and processing (Exhibit 9). Coal is produced in the U.S. from underground mines (40 percent) and surface mines (60 percent). In underground mines, most of the mining equipment is driven by electricity. In surface mines, the equipment runs on diesel fuel or electricity. This analysis estimates the direct and indirect emissions of the mining processes from Economic Census data³⁴. (For detailed calculations of the coal LCA, see Appendix A.)



Coal formations contain methane, which is released when the coal is mined. The methane content varies among different coal formations but is generally higher for underground mines than for surface mines. Underground mines use ventilation to remove the methane, which is a safety hazard, and in some cases the methane can be recovered for use or flared to reduce GHG emissions. The U.S. GHG Inventory estimates the methane emissions from coal mining. Coal mines that are no longer active (i.e., are “abandoned”) release methane as well: 7.0 MMTCO₂e in 2008 (at 25 GWP). This would add an additional 0.4 kg CO₂e/MMBtu to the coal LCA but is not included here since we do not have similar data on methane emissions from abandoned gas wells.

Data on coal transportation by mode are available from the Economic Census³⁵. More than 90 percent of coal is transported by train, with the remainder transported by barge, truck, or various combinations of these modes. This analysis derives the energy consumption per ton-mile from several sources to calculate CO₂ emissions. (See Appendix A.)

The United States is a net exporter of coal by 4 percent, so the production data are adjusted downward by that amount. Table 6 shows the adjusted upstream GHG emissions for coal, totaling 117.8 MMTCO₂e.

³⁴ U.S. Department of Commerce, *Census of Mining 2007*, Census Bureau, U.S. Department of Census

³⁵ *Ibid.*



Comparing Life Cycle Greenhouse Gas Emissions from Natural Gas and Coal

Exhibit 10. Adjusted Total Upstream GHG Emissions from Coal for 2008 (MMTCo₂e)

	Methane	Non-Combustion CO ₂	CO ₂ and N ₂ O from Combustion	Total
Production	79.9	0.0	14.0	93.9
Transportation	0.0	0.0	23.9	23.9
Total	79.9	0.0	37.9	117.8

As with the natural gas LCA, this analysis “normalizes” total emissions by the energy delivered to coal consumers (more than 90% power of whom are power generators), or 1,147 million short tons of coal in 2008. This yields a normalized upstream emission factor of 4.8 kg CO₂e/MMBtu consumed. (See Exhibit 11.) This value is about 25 percent of the upstream emissions from natural gas. The emission factor for combustion of coal is 95.1 kg/MMBtu, bringing the total end-use life-cycle emissions to 99.9 kg CO₂/MMBtu. In this case, although methane comprises 63 percent of the upstream emissions, the upstream component is only 5 percent of the total, with CO₂ emissions from the combustion of the coal itself being the dominant factor in the total life-cycle emissions.

Exhibit 11. Normalized Life-Cycle GHG Emissions from Coal for 2008 (kg CO₂e/MMBtu)

	Methane	CO ₂ and N ₂ O from Combustion	Total
Production	3.3	0.6	3.9
Transportation	0.0	1.0	1.0
Total Upstream	3.3	1.5	4.8
Coal Combustion	0.0	95.1	95.1
End Use Total	3.3	96.6	99.9

Electricity Generation

Finally, life-cycle GHG emissions per MMBtu of fuel delivered to power plants are normalized to GHG emissions per MWh of electricity generated to account for the difference in coal and natural gas power plant efficiencies. In 2008, essentially all coal-fired electricity in the United States was generated by steam-turbine power plants, which combust fuel to boil water and use the resulting steam to drive a turbine.³⁶ Many coal plants are run almost all the time at full capacity to provide baseload power. Technology has improved over the past several decades and new plants have improved combustion efficiencies, but many active plants in the U.S. fleet were built before 1970 and are less efficient.

By contrast, natural gas is used in a range of power plant technologies, each of which fills a different role in the electricity dispatch. In 2008, only 12 percent of natural gas-fired electricity was generated by steam-turbine plants, most of which were built before 1980 and are relatively inefficient. An additional 9 percent was generated by simple-cycle gas turbines, relatively inefficient plants that are used to provide peaking power during limited periods. Since 2000, a large portion of new natural gas capacity additions have been combined-cycle units, which use waste heat from gas turbines to run steam turbines.

Combined-cycle plants have superior heat rates and may be used to provide baseload or intermediate power, depending on the particular grid and the price of gas. In 2008, 79 percent of gas-fired electricity was generated by combined-cycle plants. Two coal plants in the U.S. currently gasify coal to generate electricity in a combined-cycle configuration, but such plants, called Integrated Gasification Combined Cycle (IGCC) plants, have very low market penetration today.

³⁶ All 2008 generation data from Energy Information Administration (EIA), Form EIA-923, 2008.



Comparing Life Cycle Greenhouse Gas Emissions from Natural Gas and Coal

The heat rate (the amount of fuel in Btus needed to generate a kilowatt-hour of electricity) of the electric generator is one of the most significant variables in estimating the GHG emissions per MWh of electricity.³⁷ Unless otherwise specified, this analysis uses heat rates representing the average efficiency of existing power plants in the U.S. fleet:

- **Average efficiency of existing capital stock:** National average values are based on EIA data for total gas or coal consumption for generation and total generation by each fuel. The heat rates are 8,044 Btu/kWh (41 percent efficiency) for gas generation and 11,044 Btu/kWh (31 percent efficiency) for coal generation.

A sensitivity analysis comparing life-cycle emissions results using average heat rates and heat rates representative of new natural gas and coal plants is shown in Appendix A (Exhibit A-12).

- **Efficiency of new plants:** In its *Annual Energy Outlook 2010*³⁸, EIA provides a value for a new plant in 2009, and for future plants that accounts for future cost reductions from learning and production efficiencies (“nth” plant). The values used here are the average of the two values for a gas combined-cycle plant (6,998 Btu/kWh, 49 percent efficiency) and a new supercritical coal plant (8,970 Btu/kWh, 38 percent efficiency).

Summary of Results and Sensitivity Analysis for Top=Down Analysis

Exhibit 12 compares the calculated LCA emissions (by GHG) for gas delivered to power plants for (a) natural gas using the EPA 2010 methodology, (b) natural gas using the EPA 2011 methodology, and (c) coal. In all cases, the emissions are dominated by CO₂ from final combustion of the fuel at the power plant. The upstream emissions are larger for gas, and the power plant combustion emissions are higher for coal. The LCA for coal is dominated by the CO₂ from the coal combustion itself. The upstream component is larger for natural gas, and methane is a larger component of the emissions. Using the increased methane emission estimate for gas from the 2011 methodology results in the LCA for natural gas being 11 percent higher than with the 2010 estimate. The gas life-cycle value using the 2011 methodology is 28 percent lower than the coal value.

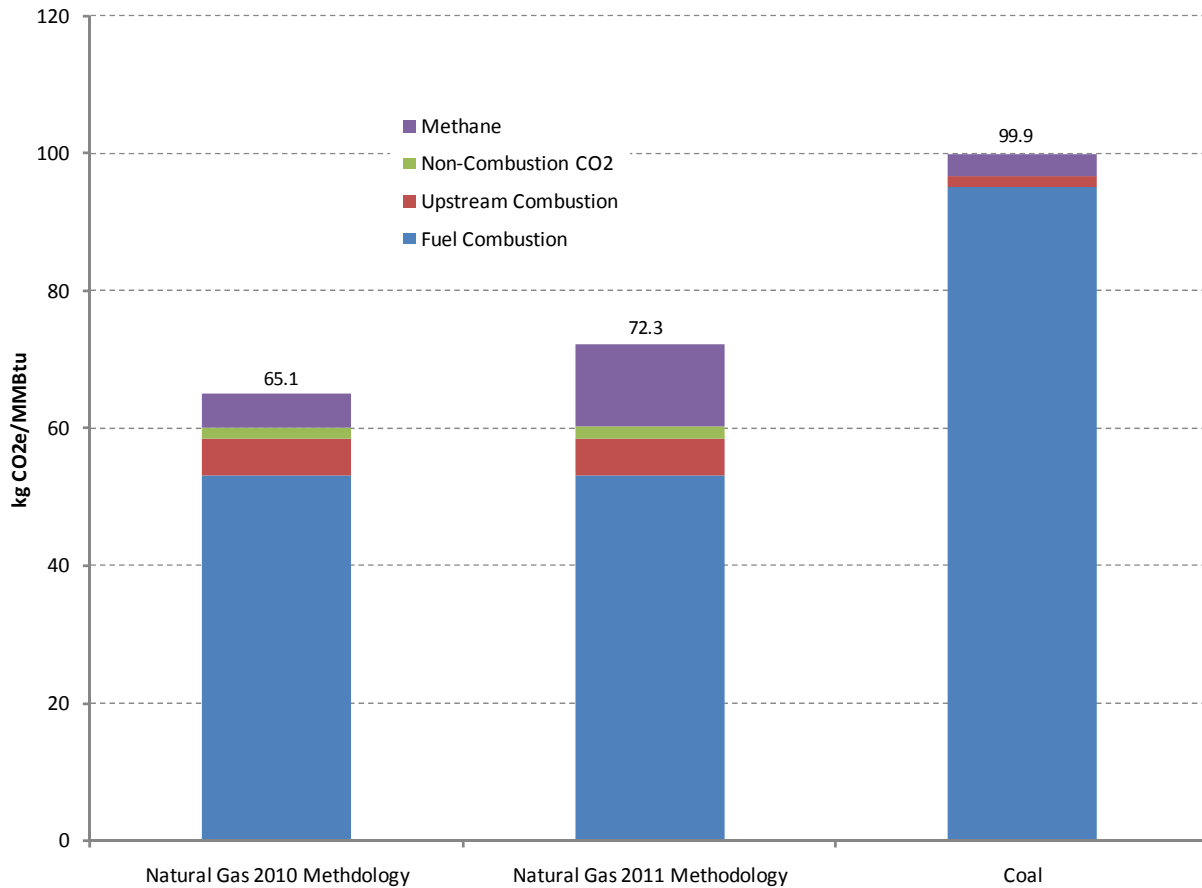
³⁷ The power industry uses efficiency and heat rate to express power plant efficiency. Heat rate in Btu/kWh = 3413/efficiency. A lower heat rate signifies a higher efficiency.

³⁸ EIA, *Assumptions to the Annual Energy Outlook 2010 – Table 8-2*, DOE/EIA-0554(2010), Energy Information Administration, U.S. Department of Energy. http://www.eia.gov/oiaf/aeo/assumption/pdf/electricity_tbls.pdf



Comparing Life Cycle Greenhouse Gas Emissions from Natural Gas and Coal

Exhibit 12: Life-Cycle Emissions as Delivered to Power Plants, 2008 (kg CO₂e/MMBtu)



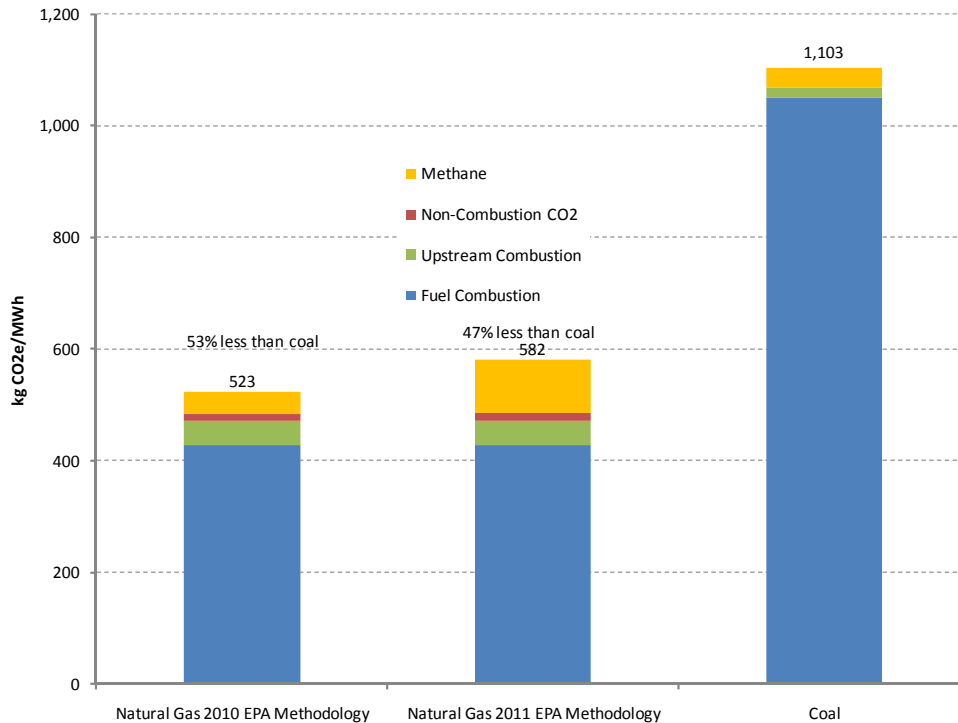
Source: DBCCA Analysis 2011

Exhibit 13 shows the LCA in terms of GHG emissions per megawatt-hour of electricity generated from gas and coal, using the national average power plant efficiencies. The gas value using the 2011 EPA methane emissions estimates is 582 kg CO₂e/MWh—or 11 percent higher than the 523 kg CO₂e/MWh calculated using data for 2010 methodology. The value for coal is 1,103 kg CO₂e/MWh. Because coal plants are on average less efficient than gas plants, the difference between gas and coal is greater than the fuel-only comparison at the burner tip prior to combustion and conversion to electricity. **Natural gas-fired electricity, using the 2011 methodology, has 47 percent lower life-cycle GHG emissions per unit of electricity than coal-fired electricity.**



Comparing Life Cycle Greenhouse Gas Emissions from Natural Gas and Coal

Exhibit 13: Electric Generating LCA, by Greenhouse Gas, 2008 (kg CO₂e/MWh)



Source: DBCCA Analysis 2011

Conclusions

Our top-down LCA of natural gas and coal-based generation using publicly available data shows that the EPA's recent revision of methane emissions increases the life-cycle GHG emissions for natural gas-fired electricity by about 11 percent from estimates based on the earlier values. Our conclusion is that, on average, natural gas-fired power generation emits significantly fewer GHGs compared to coal-fired power generation. Life-cycle emissions for natural gas generation using new EPA estimates are 47 lower than for coal-based generation when using a GWP of 25. The impact of different GWPs to our LCA can be found in Appendix B.

Nevertheless, methane, despite its shorter lifetime than carbon dioxide, is of concern as a GHG. Compared to coal-fired generation, methane emissions, including a large venting component, comprise a much larger share of natural-gas generation's GHGs. And while measurement of upstream emissions and public disclosure of those emissions still has room for improvement, methane emissions during the production, processing, transport, storage, and distribution of natural gas can be mitigated now at moderately low cost using existing technologies and best practices. Such capture potential presents a commercial and investment opportunity that would further improve the life-cycle GHG footprint of natural gas.



Comparing Life Cycle Greenhouse Gas Emissions from Natural Gas and Coal

Appendix A Detailed Methodology and Calculations

Natural Gas

The natural gas LCA addresses emissions from extraction through electricity generation for 2008. The primary data sources are the EPA *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2009* and EIA data on natural gas consumption³⁹. Exhibit A-1 shows the basic information on total emissions by industry segment for 2008. The methane emissions are from the EPA Inventory and adjusted from a GWP of 21 to a GWP of 25. The non-combustion CO₂ emissions are from the same source and include CO₂ from combustion of flared gas and the formation CO₂ vented from gas processing plants. The CO₂ from combustion is primarily from the EIA data on gas consumption in the gas industry. The gas consumed in the production segment is the “lease gas” reported by EIA, which is gas consumed in the producing areas. EIA also reports “vented and flared gas,” which is assumed here to be all flared but is already included in the EPA category of non-combustion emissions. The “processing” category includes the “plant gas” reported by EIA, and “transmission” includes the pipeline and distribution fuel reported by EIA. The total upstream emissions from these sources are 387.0 MMTCO₂e based on a 100 year GWP of 25.

Detailed data collection and verification, as well as LCA harmonization to common metrics and system boundaries are critical for improving the rigor of LCA analysis. The National Renewable Energy Laboratory’s Joint Institute for Strategic Energy Analysis, www.jisea.org, will be conducting such an evaluation in the coming months, which may improve upon the historical data sets used by EPA.

Exhibit A-1: Basic U.S. Upstream Gas Emission Data for 2008 (MMTCo₂e)

	Methane	Non-Combustion CO ₂	CO ₂ and N ₂ O from Combustion	Total
Production	146.3	11.3	47.2	204.8
Processing	18.7	21.4	19.4	59.5
Transmission	51.5	0.1	35.4	87.1
Distribution	35.6			35.6
Total	252.1	32.8	102.1	387.0

There are several additions to this basic information. First, there are some electric driven compressors on the pipeline network. This electricity consumption of 2,936.6 million kWh is from the ORNL *Transportation Data Book*⁴⁰. (That estimate is based on a fixed share of 1.5 percent of the natural gas consumption.) The emission factor for electricity throughout the analysis is 603 kg CO₂/MWh, calculated from EIA data on total generation and CO₂ emissions. This electricity consumption adds 1.8 MMTCO₂e to the pipeline emissions. There is also diesel fuel, gasoline and other petroleum fuel used in gas drilling and production that is not separately reported by EIA. This information is collected by the Economic Census⁴¹ **Error! Bookmark not defined.** but only by NAICS code and only every 10 years (the latest reporting year is 2007). The four relevant NAICS codes are: 211111 (crude petroleum and natural gas extraction); 211112 (natural gas liquid extraction); 213111 (drilling oil and gas wells); and 213112 (support activities for oil and gas operations).

Three of these codes (excepting NGL extraction) combine data for oil and gas operation. The gas portion is calculated based on the gas share of U.S. producing oil and gas wells (55.4 percent) or active drilling rigs (83.2 percent). Also, the Census lists expenditures only by fuel type. The actual consumption is estimated from the expenditures based on average price for each fuel. The consumption is then converted to CO₂ emissions using the emission factors from the EPA GHG Reporting Program. These emissions are then escalated from 2007 to 2008 based on EIA data for production (3.9 percent increase). The calculations are summarized in Exhibit A-2. Total emissions for this segment are 7.2 MMTCO₂e.

³⁹ EIA, *Natural gas navigator. Natural gas gross withdrawals and production.* http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_m.htm

⁴⁰ ORNL, *Transportation Energy Data Book, Oak Ridge National Laboratory, U.S. Department of Energy, June 2010,* <http://cta.ornl.gov/data/index.shtml>

⁴¹ U.S. Department of Commerce, *Census of Mining 2007, Census Bureau, U.S. Department of Census*



Comparing Life Cycle Greenhouse Gas Emissions from Natural Gas and Coal

Exhibit A-2: Gas Industry Upstream Non-Gas Emissions

Energy Consumption (MMBtu)						
NAICS		Distillate	Gasoline	Other	Residual Oil	Undistributed
211111	Extraction	29,055,998	10,031,608	--	6,539,144	8,502,932
211112	NGL Extraction	288,585	352,861	66,627	--	168,613
213111	Drilling	10,014,334	3,808,638	551,713	3,967,479	5,446,747
213112	Support	20,671,552	13,157,404	893,604	7,166,105	4,389,137

CO ₂ Emission Factors	Distillate	Gasoline	Other	Residual Oil	Other
	73.96	70.22	62.98	75.1	62.98

CO ₂ Emissions (MMTCO ₂ e)						
211111	Extraction	2.1	0.7	0	0.5	0.5
211112	NGL Extraction	0	0	0	0	0
213111	Drilling	0.7	0.3	0	0.3	0.3
213112	Support	1.5	0.9	0.1	0.5	0.3

Gas Share of Emissions (MMTCO ₂ e)						
21111	Extraction	1.8	0.6	0	0.4	0.4
211112	NGL Extraction	0	0	0	0	0
213111	Drilling	0.4	0.1	0	0.2	0.2
213112	Support	1.3	0.8	0	0.4	0.2

Source: EPA, ORNL, Census Bureau, DBCCA Analysis 2011

Another adjustment is for methane emissions from “associated” gas produced from oil wells. Most oil wells produce gas, much of which is captured and delivered to consumers. The EPA *Inventory of U.S. GHG Emissions* estimates methane emissions from petroleum systems to be approximately 30 MMTCO₂e per year.

Since some domestic natural gas is co-produced with petroleum, one could consider all of these emissions be included in the life-cycle analysis of emissions from the natural gas sector. However, the natural gas produced and the methane emissions are a byproduct of petroleum production. Methane emissions would occur even if no natural gas were captured and delivered for end-use consumption. In fact, the emissions might actually be higher in that case since there would be no economic incentive to capture the gas. One could also therefore maintain that it is not appropriate to count the methane emissions from petroleum production toward gas use, since they are independent of the production of gas and are related to petroleum consumption.

On the other hand, associated gas produced from oil wells is a significant segment of U.S. gross withdrawals of natural gas, and if there are methane emissions associated with that production, it seems appropriate to include them in the life-cycle analysis, even if the production is incidental to oil production. In that case, we have to evaluate how much of the methane emissions to allocate to gas production versus petroleum production.

The EPA inventory separates the methane emissions from petroleum systems at the wellhead oil separator. Methane emitted on the oil side downstream from the separator is allocated to the petroleum side, and methane emitted on the natural gas side is allocated to the natural gas side. The part that must be allocated here is the upstream production emissions, of which the largest components are miscellaneous venting and fugitives and venting from gas-powered pneumatic devices. The approach in this analysis is to simply allocate these emissions based on the energy value of oil versus gas produced from these wells.



Comparing Life Cycle Greenhouse Gas Emissions from Natural Gas and Coal

According to the EIA, the gross production of natural gas from petroleum wells in 2008 was 5.7 trillion cubic feet (Tcf)⁴². However, much of this gas (3.3 Tcf) was not gathered for sale but was reinjected into the producing formation. Some of the gas is reinjected to push more oil out of the formation. Most of the reinjection (3.0 Tcf) is from Alaska production where there is no pipeline to bring the gas to market. It is reinjected as a means of storage until the time when a pipeline may be built to the lower 48 states. In any case, the associated gas actually produced for potential sale is 2.5 Tcf. On an energy basis, this is 20 percent energy value of the net associated gas plus the 1.8 billion barrels of U.S. oil production in 2008.

Of the methane emission sources in petroleum production, we include pneumatic device venting, combustion and process upsets, miscellaneous venting and fugitives, and wellhead fugitives. Tank venting is not included because it is purely related to oil production. Total methane emissions for these sources in 2008 were 25.6 MMTCO₂e, according to the EPA inventory. Taking 20 percent of this total gives 5.0 MMTCO₂e of additional methane emissions to allocate to the natural gas LCA, increasing the unadjusted emission baseline by 1.4 percent.

With these additions (electricity, non-gas fuel, and methane from petroleum systems), total upstream gas production emissions are 402.0 MMTCO₂e.

The total emissions are then adjusted for imports. The calculations above include emissions for U.S. production, but a net 13 percent of natural gas was imported in 2008. Of this, 11.7 percent was imported by pipeline from Mexico and Canada (mostly the latter). This analysis assumes that production processes are similar throughout North America, so the production emissions are escalated by 11.7 percent to account for the pipeline imports. The remaining 1.3 percent of imports were LNG imports. LNG has a higher LCA than conventional gas due to gasification, liquefaction, and transportation processes. The LCA for LNG is estimated at 176 percent of conventional gas based on the LCA performed by NETL³⁰. The production emissions for the LNG component are increased by this amount. The adjustment for imports is the largest adjustment, increasing the emissions by about 39 MMTCO₂e, or 10 percent.

The other adjustment in this analysis is related to fugitive methane emissions from gas distribution lines at local gas distribution companies (LDCs). Methane emissions from local distribution lines are 35.6 MMTCO₂e (at 25 GWP), but many power plants receive gas deliveries directly from interstate pipelines rather than via local distribution lines. Relatively few power plants actually purchase gas from LDCs, but some receive gas deliveries from the LDCs. The EIA-176 survey⁴³ provides data on deliveries by LDCs to electric generators; however, these reported deliveries total 6.5 Tcf, which is almost equal to total gas consumption for electricity generation. This is because intrastate pipeline deliveries in California, Texas, and Florida are included in the EIA-176 survey. Excluding these three states, 59 percent of gas to electric generators is delivered by LDCs. Based on this, only 59 percent of the distribution company methane emissions are included in the adjusted values. This adjustment decreases the emissions by about 17 MMTCO₂e, or 4 percent. Exhibit A-3 shows the adjusted final upstream GHG emissions for natural gas: 423.8 MMTCO₂e. Methane emissions account for more than half of the total.

Exhibit A-3: Adjusted Total Upstream GHG Emissions from Natural Gas for 2008, using EPA 2011 Methodology for Methane (MMTCO₂e)

	Methane	Non-Combustion CO ₂	CO ₂ and N ₂ O from Combustion	Total
Production	173.7	12.9	62.2	248.7
Processing	21.3	24.4	22.2	67.9
Transmission	51.5	0.1	37.2	88.8
Distribution	18.3	0.0	0.0	18.3
Total	264.9	37.4	121.5	423.8

These total emissions are then normalized to kg CO₂e/MMBtu of delivered natural gas based on the EIA data on natural gas delivered to consumers: 21.4 trillion cubic feet (Tcf). The total normalized upstream emissions are 19.2 kg CO₂e/MMBtu. (See Exhibit A-4.) The emissions for combustion of the gas at the point of use are 53.07 kg

⁴² EIA, *Natural gas navigator. Natural gas gross withdrawals and production.* http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_m.htm

⁴³ EIA, EIA-176, "Annual Report of Natural and Supplemental Gas Supply and Disposition", Energy Information Administration, U.S. Department of Energy. <http://www.eia.gov/cfapps/ngqs/nqqs.cfm?report=RP1&CFID=5251631&CFTOKEN=51c7f7f0104e329d-3FD56B17-237D-DA68-24412047FB2CE3CB>



Comparing Life Cycle Greenhouse Gas Emissions from Natural Gas and Coal

CO₂e/MMBtu (including N₂O and unburned methane), so the total life-cycle GHG emissions at the point of use are 70.4 kg CO₂e/MMBtu. Of this, the upstream emissions are 24 percent and methane is slightly over half of the upstream component.

Exhibit A-4: Normalized Life-cycle GHG Emissions for Natural Gas for 2008, using 2011 EPA Methodology for Methane (kg CO₂/MMBtu)

	Methane	Non-Combustion CO ₂	CO ₂ and N ₂ O from Combustion	Total
Production	7.9	0.6	2.8	11.3
Processing	1.0	1.1	1.0	3.1
Transmission	2.3	0.0	1.7	4.0
Distribution	0.8	0.0	0.0	0.8
Total Upstream	12.0	1.7	5.5	19.2
Fuel Combustion	0	0	53.1	53.1
Total	12.0	1.7	58.6	72.3

The same methodology is applied using EPA's 2010 estimate of methane emissions, to show the effect of the updated, increased 2011 methane emission estimate. Exhibits A-5 and A-6 show the total and normalized emissions for this case. The normalized upstream emissions with the old data are 12.0 kg CO₂e/MMBtu. Including the end-use gas combustion; total life-cycle emissions including end-use combustion are 65.1 kg CO₂/MMBtu, with the upstream portion accounting for 20 percent. In this case, methane makes up only about 40 percent of the upstream gas GHG footprint.

Exhibit A-5: Adjusted Total Upstream GHG Emissions from Natural Gas, 2008, using 2010 EPA Methodology for Methane (MMTCo₂e)

	Methane	Non-Combustion CO ₂	CO ₂ and N ₂ O from Combustion	Total
Production	25.9	9.7	62.2	97.8
Processing	17.7	24.4	22.2	64.2
Transmission	46.9	0.1	37.2	84.2
Distribution	18.3	0.0	0.0	18.3
Total	108.8	34.2	121.5	264.6

Exhibit A-6: Normalized Life-cycle GHG Emissions for Natural Gas for 2008, using 2010 EPA Methodology for Methane (kg CO₂/MMBtu)

	Methane	Non-Combustion CO ₂	CO ₂ and N ₂ O from Combustion	Total
Production	1.2	0.4	2.8	4.4
Processing	0.8	1.1	1.0	2.9
Transmission	2.1	0.0	1.7	3.8
Distribution	0.8	0.0	0.0	0.8
Upstream Total	4.9	1.6	5.5	12.0
Fuel Combustion	0	0	53.1	53.1
Total	4.9	1.6	58.6	65.1



Comparing Life Cycle Greenhouse Gas Emissions from Natural Gas and Coal

Coal LCA

The upstream energy consumption for coal production is calculated using the 2007 Economic Census⁴⁴ data on fuel and electricity consumption in the same way as the non-gas fuel for gas production. In this case, there is a separate NAICS code for coal production, so no adjustments are necessary. The same CO₂ emission factors and the emission factor for electricity use are used as for the data on gas production. (See Exhibit A-7.) The values are adjusted from 2007 to 2008 based on the production in each year—a 2.2 percent increase. The total CO₂ emissions from energy consumption for coal production are 14.0 MMTCO₂e. Methane emissions from coal mines of 67.1 MMTCO₂e (79.9 at 25 GWP) are taken from the EPA GHG inventory. Methane from abandoned coal mines is not included.

Exhibit A-7: Upstream GHG Calculation for Coal

	Coal	Distillate	Natural Gas	Gasoline	Residual Oil	Other	Electricity (MWh)
MMBtu	3,607,020	52,597,178	2,487,920	4,846,529	25,739,212	2,039,820	11,444,477
kg CO ₂ /MMBtu	94.38	73.96	53.02	70.22	75.10	62.98	603.01
MMTCO ₂ e	0.34	3.89	0.13	0.34	1.93	0.13	6.90

The estimate of transportation emissions is based on the Commodity Flow Summary⁴⁵ developed by the U.S. Department of Transportation and Census Bureau, which provides information on ton-miles of coal transported by different modes. Rail is the primary mode of transportation, with rail-only accounting for 91 percent of the ton-miles and rail and other modes (truck and barge) accounting for the remainder. This analysis applies a ton-mile fuel consumption factor^{46, 47, 48} to calculate fuel consumption and converts the fuel consumption to CO₂ using the same EPA emission factors used for other sectors. (See Exhibit A-8.) For mixed mode, rail or barge are assumed to account for 75 percent of the ton-miles and truck for 50 percent. Most coal is delivered via dedicated equipment—e.g., a coal unit train travels only to and from the mine to the power plant. Thus, the fuel consumed in returning empty to the mine must be included. This analysis assumes 100-percent empty return as part of the energy consumption, with the empty fuel consumption being one-third of the loaded consumption based on the weight of the empty vehicle. The total consumption calculated is 23.9 MMTCO₂.

Exhibit A-8: GHG Calculation for Coal Transportation

Mode	Ton-Miles (million)	Fuel Consumption (ton-mi/gal)	GHG Emissions (MMTCO ₂)	Round-Trip Emissions (MMTCO ₂)
Truck	14,002	110.00	1.28	1.67
Rail	773,290	480.00	16.26	21.13
Water	6,548	730.00	0.09	0.12
Truck and rail	785	388.00	0.02	0.03
Truck and water	7,257	575.00	0.13	0.17
Rail and water	26,994	605.00	0.45	0.59
Other multiple modes	4,353	480.00	0.09	0.12
Other and unknown modes	2,567	480.00	0.05	0.07
Total	835,796	-	18.38	23.89

In the case of coal, the U.S. is a net exporter of about 4 percent of its production, so the total production emissions are adjusted downward by this amount to calculate the emissions attributable to coal consumed in the U.S. Exhibit A-9 shows the final adjusted upstream emissions: 117.8 MMTCO₂e.

⁴⁴ U.S. Department of Commerce, *Census of Mining 2007*, Census Bureau, U.S. Department of Census

⁴⁵ U.S. Department of Transportation, *Research and Innovative Technology Administration, Bureau of Transportation Statistics and U.S. Census Bureau, 2007 Commodity Flow Survey*.

⁴⁶ Federal Railroad Administration, "Comparative Evaluation of Rail and Truck Fuel Efficiency on Competitive Corridors", November 19, 2009.

⁴⁷ Army Corps of Engineers, "Waterborne Commerce Statistics Center", <http://www.ndc.iwr.usace.army.mil/data/data1.htm>

⁴⁸ American Railroad Association



Comparing Life Cycle Greenhouse Gas Emissions from Natural Gas and Coal

Exhibit A-9: Adjusted Total Upstream GHG Emissions from Coal, 2008 (MMTCO₂e)

	Methane	Non-Combustion CO ₂	CO ₂ and N ₂ O from Combustion	Total
Production	79.9	0.0	14.0	93.9
Transportation	0.0	0.0	23.9	23.9
Total	79.9	0.0	37.9	117.8

These values are then normalized by the total 2008 consumption of coal in the U.S. of 1,147 million tons of coal, assuming an average heating value of 10,250 Btu/lb.⁴⁹ This yields a normalized upstream emission factor of 4.3 kg CO₂/MMBtu consumed. (See Exhibit A-10.) The value is about 25 percent of the upstream emissions from natural gas. The emission factor for combustion of coal is 95.1 kg CO₂e/MMBtu, bringing the total end use life-cycle emissions to 99.9 kg CO₂/MMBtu. In this case, although methane is still 63 percent of the upstream emissions, the upstream component is only 4 percent of the total, with the CO₂ emissions from the coal itself being the dominant factor.

Exhibit A-10: Normalized Upstream GHG Emissions for Coal for 2008 (kg CO₂/MMBtu)

	Methane	CO ₂ and N ₂ O from Combustion	Total
Production	3.3	0.6	3.9
Transportation	0.0	1.0	1.0
Total Upstream	3.3	1.5	4.8
Coal Combustion	0.0	95.1	95.1
End Use Total	3.3	96.6	99.9

Electricity Generation

The efficiency⁵⁰ of the electric generator is one of the most significant variables in estimating the GHG emissions per MWh of electricity. This analysis looks at two values:

- **National average efficiency values** based on EIA data^{51, 52, 53, 54} for total gas or coal consumption for generation and total generation by each fuel. (See Exhibit A-11.)
- **Efficiency⁵⁵ for new power plants** assumed by the EIA in its *Annual Energy Outlook 2010*³⁸. EIA provides a value for a new plant in 2009 and for subsequent plants (“nth plant”) of each type for which the cost may be lower due to learning and production improvement. The values used here are the average of the values for a gas combined-cycle plant (6,998 Btu/kWh, 49 percent efficiency) and a new supercritical coal plant (8,970 Btu/kWh, 38 percent efficiency). (See Exhibit A-12.)

Exhibit A-11: Calculation of Average Power Plant Efficiencies

	Energy Consumption (Quads)	Generation (Billion kWh)	Heat Rate (Btu / kWh)	Efficiency
Gas	7	883.00	8,044.00	0.42
Coal	22	1,986.00	11,044.00	0.31

⁴⁹ EIA, *Annual Coal Data*, Energy Information Administration, U.S. Department of Energy, http://www.eia.gov/totalenergy/data/annual/pdf/sec7_5.pdf

⁵⁰ The power industry uses efficiency and heat rate to express power plant efficiency. Heat rate is Btu/kWh = 3413/efficiency. A lower heat rate signifies a higher efficiency.

⁵¹ EIA, *Electric Power Monthly*, Energy Information Administration, U.S. Department of Energy, http://www.eia.doe.gov/cneaf/electricity/epm/table2_4_a.html

⁵² EIA, *Electric Power Monthly*, Energy Information Administration, U.S. Department of Energy, <http://www.eia.doe.gov/aer/txt/ptb0802a.html>

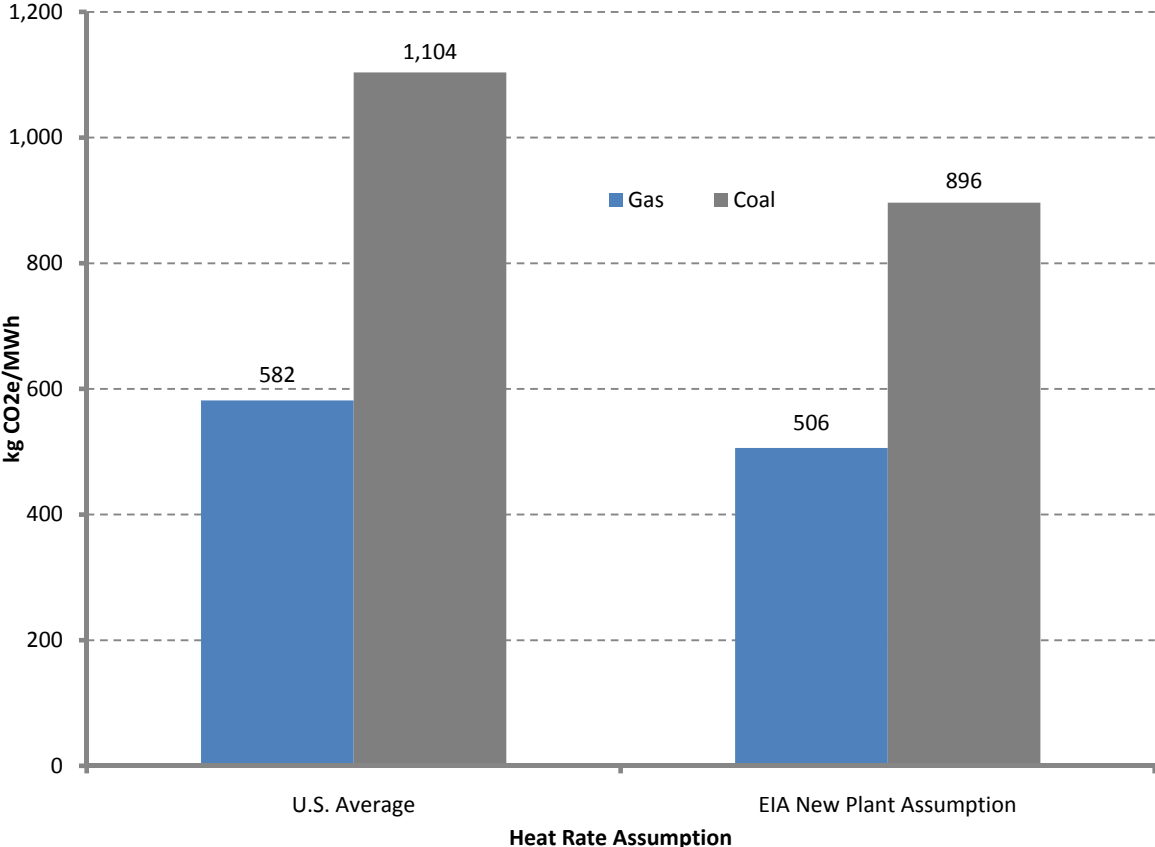
⁵³ EIA, *Annual Energy Review*, Energy Information Administration, U.S. Department of Energy, http://www.eia.doe.gov/cneaf/electricity/epm/table2_1_a.html

⁵⁴ EIA, *Quarterly Coal Report*, U.S. Department of Energy, <http://www.eia.gov/cneaf/coal/quarterly/html/t32p01p1.pdf>



Comparing Life Cycle Greenhouse Gas Emissions from Natural Gas and Coal

Exhibit A-12: Effect of Power Plant Heat Rate on Life-Cycle Emissions



Source: DBCCA analysis, 2011.



Comparing Life Cycle Greenhouse Gas Emissions from Natural Gas and Coal

Appendix B Effect of Global Warming Potential (GWP)

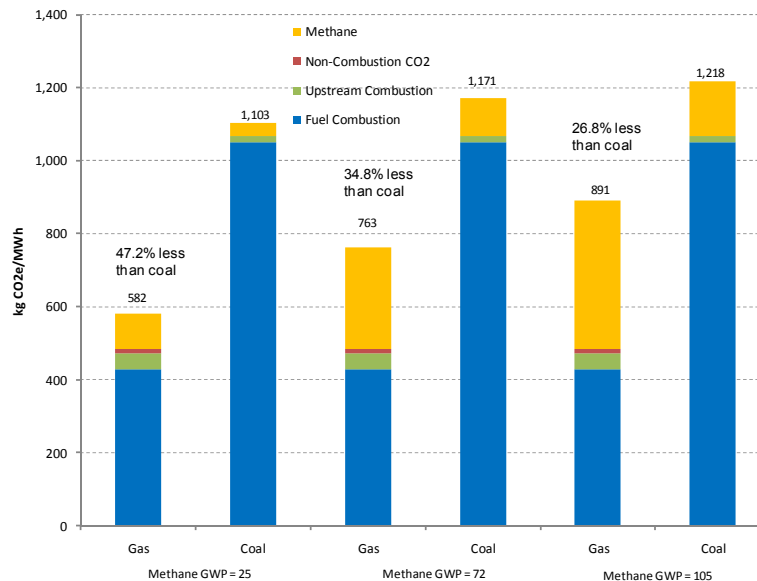
Methane is a potent GHG and its effect varies depending on the lifetime over which it is evaluated. The IPCC uses a 100 year lifetime for its analysis and a 100 year GWP of 25 for methane. Others believe that short-lived GHGs should be evaluated on a 20 year lifetime.

In its recently completed study on natural gas, MIT explains the reasons that a 100 GWP is commonly used:

“Because the various GHGs have different lives in the atmosphere (e.g., on the scale of a decade for methane, but centuries for CO₂), the calculation of GWPs depends on the integration period. Early studies calculated this index for 20-, 100- and 500-year integration periods. The IPCC decided to use the 100-year measure, and it is a procedure followed by the U.S. and other countries over several decades. An outlier in this domain is the Cornell study which recommends the application of the 20-year value in inter-fuel comparison. A 20-year GWP would emphasize the near-term impact of methane but ignore serious longer-term risks of climate change from GHGs that will remain in the atmosphere for hundreds to thousands of years, and the 500-year value would miss important effects over the current century. Methane is a more powerful GHG than CO₂, and its combination of potency and short life yields the 100-year GWP used in this study.”⁵⁶

In addition, scientific work continues on the appropriate GWPs for different GHGs. Although the IPCC 20-year GWP for methane is 72, new work by Shindell et al⁵⁷ proposes a 20-year GWP of 105 for methane. Exhibit B-1 above shows the effect of different methane GWPs on the LCA using the EPA 2011 methodology. Since methane is a much larger component of the LCA for natural gas, the GWP has a much larger effect on gas than coal. Going from the 100 year GWP to the 20-year GWP of 72 increases life-cycle emissions for natural gas by 31 percent and for coal by only 6 percent. At the GWP of 72, the power plant emissions for natural gas are 35 percent lower than those for coal. At the 105 GWP, the emissions for the gas-fired plant are 27 percent lower than those for coal.

Exhibit B-1: Effect of Methane GWP on Life-Cycle Emissions



Source: DBCCA Analysis 2011

⁵⁶ *The Future of Natural Gas*, Moniz, Ernest J.; Jacoby, Henry D.; Meggs, Anthony J.M. (Study co-chairs), MIT Energy Initiative, 2011.

⁵⁷ Shindell DT, Faluvegi G, Koch DM, Schmidt GA, Unger N, Bauer SE (2009) Improved attribution of climate forcing to emissions. *Science* 326:716–718



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