Argonne NATIONAL LABORATORY

ANL/ESD/11-11

Life-Cycle Analysis of Shale Gas and Natural Gas

Energy Systems Division

About Argonne National Laboratory

Argonne is a U.S. Department of Energy laboratory managed by UChicago Argonne, LLC under contract DE-AC02-06CH11357. The Laboratory's main facility is outside Chicago, at 9700 South Cass Avenue, Argonne, Illinois 60439. For information about Argonne and its pioneering science and technology programs, see www.anl.gov.

Availability of This Report

This report is available, at no cost, at http://www.osti.gov/bridge. It is also available on paper to the U.S. Department of Energy and its contractors, for a processing fee, from:

U.S. Department of Energy
Office of Scientific and Technical Information
P.O. Box 62
Oak Ridge, TN 37831-0062
phone (865) 576-8401
fax (865) 576-5728
reports@adonis.osti.gov

ANL/ESD/11-11

Life-Cycle Analysis of Shale Gas and Natural Gas

by
C.E. Clark, J. Han, A. Burnham, J.B. Dunn, M. Wang
Center for Transportation Research
Energy Systems Division, Argonne National Laboratory

December 2011

CONTENTS

FIGURES

TABLES

TABLES (CONT.)

ACKNOWLEDGMENTS

This study was supported by the Vehicle Technologies Program within the Office of Energy Efficiency and Renewable Energy of U.S. Department of Energy under Contract Number DE- AC02-06CH11357. We would like to thank Kevin Stork and Linda Bluestein from the Vehicle Technologies Program for their support. We also thank our Argonne National Laboratory colleagues Chris Harto for assistance in developing the methods for the management of flowback water from shale gas wells and Shabbir Shamsuddin and Michael McLamore for their expertise in natural gas pipeline infrastructure. Finally, we are grateful to Lisa Hanle, U.S. Environmental Protection Agency, and Douglas Sechler, ICF International, for providing additional information on the critical assumptions of EPA's revised emissions estimates.

LIFE-CYCLE ANALYSIS OF SHALE GAS AND NATURAL GAS

Corrie E. Clark, Jeongwoo Han, Andrew Burnham, Jennifer B. Dunn, Michael Wang
Center for Transportation Research, Argonne National Laboratory

December 2011

ABSTRACT

The technologies and practices that have enabled the recent boom in shale gas production have also brought attention to the environmental impacts of its use. Using the current state of knowledge of the recovery, processing, and distribution of shale gas and conventional natural gas, we have estimated up-to-date, life-cycle greenhouse gas emissions. In addition, we have developed distribution functions for key parameters in each pathway to examine uncertainty and identify data gaps — such as methane emissions from shale gas well completions and conventional natural gas liquid unloadings — that need to be addressed further. Our base case results show that shale gas life-cycle emissions are 6% lower than those of conventional natural gas. However, the range in values for shale and conventional gas overlap, so there is a statistical uncertainty regarding whether shale gas emissions are indeed lower than conventional gas emissions. This life-cycle analysis provides insight into the critical stages in the natural gas industry where emissions occur and where opportunities exist to reduce the greenhouse gas footprint of natural gas.

ACRONYMS AND ABBREVIATIONS

API	American Petroleum Institute
Argonne	Argonne National Laboratory
AGR	acid gas removal
CNG	compressed natural gas
EIA	Energy Information Administration
EPA	U.S. Environmental Protection Agency
EUR	estimated ultimate recovery
GAO	U.S. Government Accountability Office
GHG	greenhouse gas
GREET	Greenhouse gases, Regulated Emissions, and Energy use in Transportation model
GWP	global warming potential
IPCC	Intergovernmental Panel on Climate Change
LCA	life-cycle analysis
LUG	lost and unaccounted for gas
NESHAP	National Emission Standards and Hazardous Air Pollutants
NG	natural gas
NGCC	natural gas combined cycle
REC	reduced emission completion
SG	shale gas
T&S	transmission and storage
VMT	vehicle-mile traveled
WTW	well-to-wheels

Units of Measure

bbl	barrel(s)
Bcf	billion cubic feet
Btu	British thermal unit(s)
ft	foot, feet
gal	gallon(s)
gCO_2e/MJ	grams of carbon dioxide equivalent per megajoule
gCO_2e/kWh	grams of carbon dioxide equivalent per kilowatt-hour of electricity generated
gCO_2e/mile	grams of carbon dioxide equivalent per mile
h	hour(s)
hp	horsepower
kWh	kilowatt-hour(s)
L	liter(s)
m	meter(s)
Mcf	thousand cubic feet
MJ	megajoule(s)
mmBtu	million-Btu
s	second(s)

This page intentionally left blank.

1 INTRODUCTION

Production of natural gas (NG) from shale formations first occurred when the first gas well was completed in 1821 in Fredonia, New York; however, the low permeability of shale formations posed both technical and economic challenges to large-scale development. Large-scale shale gas production started in the Barnett Shale in the 1980s, and by 2006, through advances in drilling technologies and higher NG prices, the success in the Barnett Shale led to rapid expansion into other formations, including the Haynesville, Marcellus, and Fayetteville shales. The development of this resource has generated interest in expanding NG usage in such areas as electricity generation and transportation.

It is anticipated that shale gas will provide the largest source of growth in the U.S. natural gas supply through 2035. In 2009, shale gas contributed 16% of the U.S. natural gas supply. By 2035, it is estimated that its contribution will increase to 47% of total U.S. production of natural gas, with this anticipated growth in production raising the natural gas contribution to electricity generation from 23% in 2009 to 25% in 2035 (EIA 2011a).

The Energy Information Administration (EIA) assumes that there are 827 trillion cubic feet of technically recoverable shale gas in the United States. Shales that are considered to be important include the Marcellus, Haynesville, Fayetteville, and Barnett. Other important plays include the Antrim, Eagle Ford, New Albany, and Woodford (Figure 1).

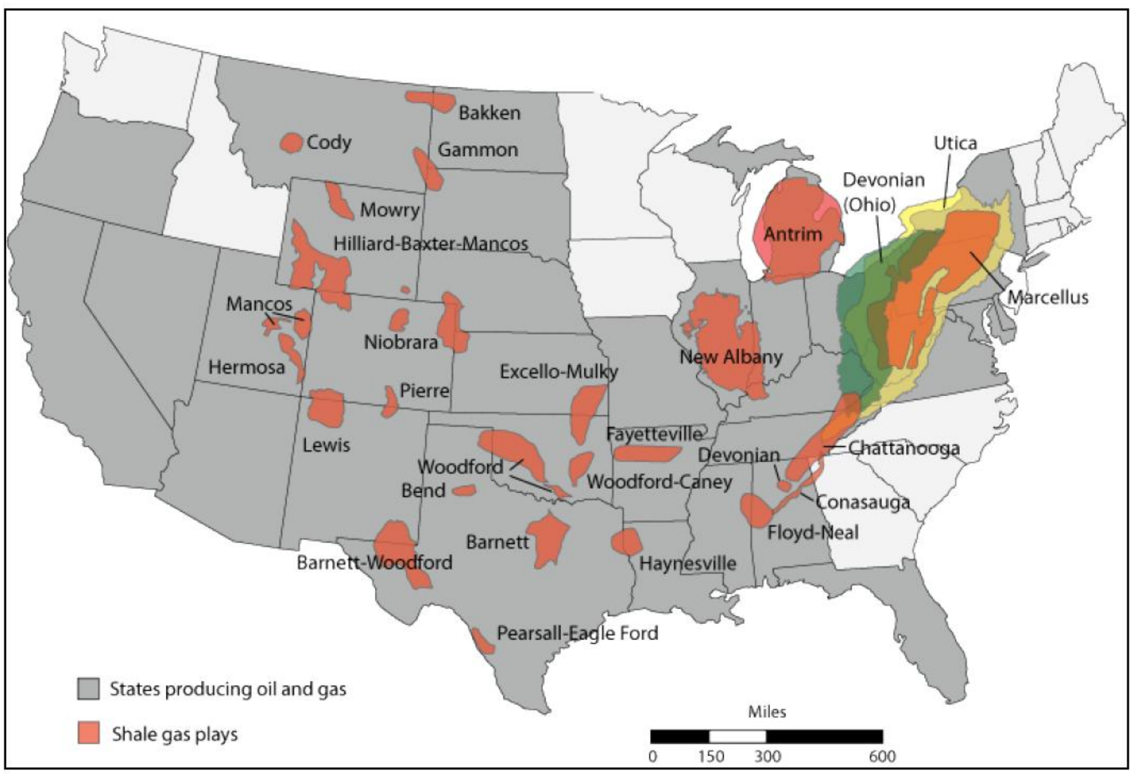

FIGURE 1 U.S. Shale Gas Plays (Veil 2010)

With significant potential growth in unconventional gas production, the life-cycle impacts of natural gas may change. “Unconventional gas” refers to gas produced from low-permeability reservoirs, which include tight sands, coal bed methane, and shale gas reservoirs. Argonne National Laboratory (Argonne) conducted a life-cycle analysis to compare the materials, energy requirements, and emissions associated with producing, processing, transporting, and consuming natural gas produced from conventional natural gas resources and shale gas resources. Argonne’s GREET (Greenhouse gases, Regulated Emissions, and Energy use in Transportation) model had previously developed the conventional gas pathway (Wang et al. 2007; Brinkman et al. 2005; Wang 1999; Wang and Huang 1999); however, prior versions did not include shale gas. Furthermore, the well field infrastructure, construction fuel consumption, and well completion emissions were not included for the conventional NG pathway. For this study, these previously excluded activities were incorporated into GREET’s conventional gas pathway, and the shale gas pathway was developed and added to GREET.

2 METHODS

The assumptions used to update the conventional gas pathway and develop the shale gas life-cycle inventory are described here. The U.S. Environmental Protection Agency (EPA) methodology for determining the greenhouse gas (GHG) emissions from the natural gas sector as part of the U.S. GHG Inventory, a significant data source for our work, is also summarized. Finally, this section contains detailed explanations of the methodology and assumptions in Howarth et al. (2011) for understanding the differences between the results of those researchers and our own.

2.1 Life-Cycle Analysis Approach

In our life-cycle analysis (LCA) of shale gas and conventional NG, we include fuel recovery, fuel processing, and fuel use, as well as transportation and distribution of fuels. In addition, we include the establishment of infrastructure, such as gas well drilling and completion. Figure 2 below shows the particular stages included in our study for both shale gas and conventional NG life cycles.

FIGURE 2 System Boundary for Shale and Conventional NG Pathways

Functional units for LCA directly affect the meaning of LCA results. In our study, we included three functional units: per-megajoule (MJ) of fuel burned (for comparison with Howarth et al. 2011), per-kilowatt-hour (kWh) of electricity produced by targeting electricity generation as an end use of shale gas and natural gas, and per-mile driven for transportation services by targeting the transportation sector for expanded gas use. The latter two functional units take into account efficiencies of energy conversion into energy services, as well as efficiencies and emissions of energy production. There are large variations and uncertainties in data for critical LCA stages in our study. Therefore, to systematically address uncertainties, we developed statistical distribution functions for the key parameters in each pathway in order to perform stochastic modeling of the pathways evaluated in this study.

2.2 Data Sources and Key Parameters Associated with Natural Gas Recovery

The EPA develops the U.S. GHG emissions inventory annually. This effort accumulates large amounts of GHG data as EPA develops methodologies to estimate emissions for different sectors, including the oil, coal, and NG sectors. The EPA methodologies and data are widely used by others, including by us, for performing GHG analyses of specific energy systems. A summary of key emission factors considered in the recovery of natural gas is provided in Table 1. Each stage and the assumptions behind its associated emissions are described in Sections 2.2.4 and 2.2.5.

TABLE 1 Selected Activity Factors for the Recovery of Natural Gas

Stage	Sample Emission Sources for Shale and Conventional Gas Unless Otherwise Noted
Well Completions	• Drill out methane (CH_4) venting • Flow back CH_4 venting (shale only)
Workovers	• CH_4 venting
Liquid Unloading	• CH_4 venting (conventional only)
Miscellaneous Venting	• Field separation equipment • Gathering compressors • Normal operations • Condensate collection • Compressor venting • Upsets
Flaring	• Carbon dioxide (CO_2) emissions

In its most recent inventory estimation, EPA made major methodological changes to how it analyzes the total CH_4 emissions of the U.S. NG system (EPA 2011). While EPA's CH_4 emission factors for the U.S. NG system are based primarily on a joint study by the gas industry and EPA (Harrison et al. 1996), the EPA updates activity factors, such as length of the U.S. pipeline network and number of producing gas wells, on an annual basis. EPA also makes minor adjustments to emission factors where appropriate and includes additional CH_4 sources when data become available. We note that in its 2011 inventory estimation, EPA made a significant upward adjustment of CH_4 emissions from the U.S. NG system, such that total CH_4 emissions more than doubled from levels used in the previous inventory. Table 2 presents the changes to selected EPA emission factors.

TABLE 2 Comparison of Changes to Selected EPA Emissions Factors (EPA 2010b)

Emissions Source	Previous Emissions Factor	Revised Emissions Factor	Units
Well venting for liquids unloading	1.02	11	CH_4 metric tons/year-well
Gas venting during well completions			
Conventional well	0.02	0.71	CH_4 metric tons/year-completion
Unconventional well	0.02	177	CH_4 metric tons/year-completion
Gas venting during well workovers			
Conventional well	0.05	0.05	CH_4 metric tons/year-workover
Unconventional well	0.05	177	CH_4 metric tons/year-workover
Centrifugal compressor wet seal degassing venting	0	233	CH_4 metric tons/year-compressor

Note: Conversion factor of 0.01926 metric tons = 1 Mcf.

The underlying reasons for these adjustments are explained in Sections 2.2.4 and 2.2.5. Burdens associated with NG recovery as part of the EPA GHG inventory and those burdens outside of the GHG inventory are detailed in the following subsections.

Table 3 summarizes the key parameters that are discussed in the following subsections and are included in the natural gas pathways.

TABLE 3 Key Parameters for Natural Gas Simulation in GREET (mean values with ranges in parentheses)

Parameter	Units	Conventional	Shale	Source
Well Lifetime	Years	30	30	Industry and Argonne Assumption
Bulk Gas Methane Content	%	85 (69–95)	80 (40–97)	Hanle 2011
Production over Well Lifetime (estimated ultimate recovery)	NG million cubic feet	1,550 (1,320–1,780)	3,460 (1,600–5,320)	Conv: EIA 2011b; Shale: Chesapeake Energy 2010
Well Completion and Workovers (venting)	Metric ton CH_4 per completion or workover	0.71	177 (13.5–385)	EPA 2010b
CH_4 Reductions for Completion or Workovers	%	0	41 (37–70)	EPA 2011; EPA 2010a
Number of Workovers per well lifetime	Workovers per lifetime	2	2	EPA 2010b
Liquid Unloadings (venting)	Metric ton CH_4 per unloading	0.86	0	EPA 2010b
Liquid Unloading Events	Unloadings per year	31 (11–51)	0	EPA 2010b
CH_4 Reductions for Liquid Unloadings	%	12 (8–15)	0	EPA 2011; EPA 2010a
Wells Requiring Unloadings	%	41.3	0	EPA 2010b
Well Equipment (leakage and venting)	Grams CH_4 per million Btu NG	209 (114–303)	209 (114–303)	GAO 2010; EPA 2011
CH_4 Reductions for Well Equipment	%	28 (18–37)	28 (18–37)	EPA 2011; EPA 2010a
Well Equipment (CO_2 from flaring)	Grams CO_2 per million Btu NG	454 (369–538)	454 (369–538)	GAO 2010; EPA 2011
Well Equipment (CO_2 from venting)	Grams CO_2 per million Btu NG	41	41	EPA 2011
Processing (leakage and venting)	CH_4: % of NG produced	0.15 (0.06–0.23)	0.15 (0.06–0.23)	EPA 2011
Processing (CO_2 from venting)	Grams CO_2 per million Btu NG	878 (615–1140)	878 (615–1140)	EPA 2011
Transmission and Storage (leakage and venting)	CH_4: % of NG produced	0.39 (0.2–0.58)	0.39 (0.2–0.58)	EPA 2011
Distribution (leakage and venting)[a]	CH_4: % of NG produced	0.28 (0.09–0.47)	0.28 (0.09–0.47)	EPA 2011

[a] Distribution accounts for leakage and venting from terminals to refueling stations. It does not apply to major industrial users, such as electricity generators.

2.2.1 Estimated Ultimate Recovery

Given that the EPA GHG inventory emissions from NG well completions and liquid unloadings are estimated on a per-well basis, it was necessary to determine the estimated ultimate recovery (EUR) of gas from a well to amortize these periodic emissions over the total amount of natural gas produced. For shale gas wells, a range was developed for EURs according to the per-well weighted average of four major plays: Marcellus, Barnett, Haynesville, and Fayetteville. The high estimates were based upon industry average–targeted EURs (Mantell 2010b). The low estimates were based upon a review of emerging shale resources developed by INTEK, Inc., for the EIA (INTEK 2011). The INTEK analysis captured the variability in EUR within a play by evaluating the EUR for the best area, the average area, and the below-average area in a play. INTEK further presented EURs for active portions and undeveloped portions of major plays, and generally, the active portions of the play had larger EURs than did the undeveloped areas. Comparing the EURs with the industry average–targeted EURs, the active EURs reported in INTEK were similar, with the exception of the Marcellus play. While the active reported EURs reported by INTEK were lower for the Marcellus than the industry average–targeted EUR, the industry average–targeted EUR was contained within the range of EURs presented for the best, average, and below-average EURs for the Marcellus-developed area. We averaged the high and low values to estimate our Base Case shale gas well EUR of 3.5 billion cubic feet (Bcf), as shown in Table 4.

TABLE 4 Lifetime Production Estimates According to Play (INTEK 2011; Mantell 2010b)

	Low EUR Estimates (Bcf)	High EUR Estimates (Bcf)
Barnett	1.4	3.0
Marcellus	1.4	5.2
Fayetteville	1.7	2.6
Haynesville	3.5	6.5
Per-Well Weighted Average	1.6	5.3

The estimates in Table 4 are for the bulk gas, which is a mixture containing methane in addition to other gases such as ethane, propane, carbon dioxide, and nitrogen.

For the conventional NG EUR, we assumed an average production rate over the lifetime of the well according to EIA production data and EPA well compositional makeup, recognizing that production rates typically decline over time, to estimate a Base Case EUR of 1.6 Bcf (EPA 2011, EIA 2011b). Our estimate of conventional EUR is comparable to a value from an analysis of Texas wells prior to large-scale shale gas production (Swindell 2001). It should be noted when comparing the EURs that shale gas recovery typically uses horizontal drilling to access large rock volumes, whereas conventional gas recovery often uses multiple vertical wells, each accessing a smaller rock volume. To account for these differences and enable comparison, the analysis evaluates impacts on a per-million-Btu (mmBtu) basis. In addition, in the case of conventional gas, it may be that the highly productive wells have ceased production and modern wells return relatively less gas, as shown by the fall in the EUR for Texas over the years (Swindell 2001). As the large-scale recovery of NG from shale plays is a relatively new pursuit, the EUR may not reflect future conditions when the technologies that support large-scale shale gas recovery are more mature. For emissions associated with processing, transmission, storage, and distribution, we based our emissions calculations on total production of shale gas (SG) and NG as we did not need to differentiate by gas source (EIA 2011b).

2.2.2 Well Design, Drilling, and Construction

The drilling phase of the NG life cycle requires the use of drill rigs, fuel, and materials, including the casing, cement, liners, mud constituents, and water. Water is used during the well construction stage in drilling fluids, for cementing the casing in place, and for hydraulically fracturing the well in the case of shale gas. For the purposes of our analysis, the horizontal shale gas wells were based on designs for the 4H, 5H, and 6H Carol Baker wells and modified according to the depth of the shale play (Range Resources 2011a–c). For horizontal drilling, a well is drilled down to the depth of the play and turned approximately 90 degrees to run laterally (horizontally) through the play for 2,000 to 6,500 feet (ft). Vertical wells draw from a much smaller area within a play. The conventional NG scenario assumed a vertical well design, which was based upon a design from the Mississippi Smackover and adjusted to the national average depth of gas wells (Bourgoyne et al. 1991; EIA 2011b). Because of the long lateral reach of horizontal wells, they can access more of the play, which typically increases production on a per-well basis.

The total volume of drilling muds, or fluids, used to lubricate and cool the drill bit, maintain downhole hydrostatic pressure, and convey drill cuttings from the bottom of the hole to the surface depends upon the volume of the borehole and the physical and chemical properties of the formation. The ratio of barrels (bbl) of drilling mud to bbl of annular void used in this assessment was 5:1 according to data obtained from the literature (EPA 1993). The material inventory assumes use of water-based fluids for the Barnett and Haynesville plays. Analysis of the Marcellus and Fayetteville plays assumes use of air drilling through the upper portion of the well to a depth of 392 ft and water drilling below that depth (GWPC and ALL 2009). For the water-based drilling muds, a ratio of 1 bbl of water to 1 bbl of drilling mud was assumed. The composition of the mud was adapted from Mansure (2010) to provide the required drilling fluid properties. The dominant material — by several orders of magnitude — was bentonite; as a result, the other materials were ignored for this study.

To determine fuel consumption, the following assumptions were made:

- The drill rig operates with a 2,000-horsepower (hp) engine,
- The engine consumes diesel fuel at a rate of 0.06 gallon (gal)/hp/hour (h), and
- The drill rig runs at 45% of capacity.

These assumptions are similar to those reported by Tester et al. (2006), EPA (2004a), and Radback Energy (2009). By assuming that the drill rig operates 24 hours per day and then using an average number of days drilled from Overbey et al. (1992) and extrapolating to the various plays according to depth, the total diesel fuel required for drilling can be determined. Although diesel fuel requirements for on-site activities and transportation burdens for diesel and water were included in the inventory, the transportation burdens of materials (e.g. mud, cement, steel) were not included. The summary of materials, water, and fuel used to drill and construct the horizontal wells is presented in Table 5.

TABLE 5 Material Requirements for Drilling and Constructing a Typical Well by Play (units are in metric tons per well unless otherwise indicated)

	Shale Gas				Conventional Gas	
Well Drilling	**Barnett**	**Marcellus**	**Fayetteville**	**Haynesville**	**Low Estimate**	**High Estimate**
Steel	163	145	114	226	40	55
Portland Cement	267	239	187	371	84	115
Gilsonite (asphaltite)	9	8	7	13	13	18
Diesel Fuel (gallons)	61,768	55,080	43,041	85,845	17,820	24,300
Bentonite	61.38	44	42.99	68.23	19.64	26.88
Soda Ash	1.06	0.7	0.74	1.13	0.34	0.46
Gelex	0.04	-	0.03	-	0.01	0.02
Polypac	1.60	1.4	1.12	2.22	0.53	0.72
Xanthum Gum	0.81	0.7	0.57	1.13	0.27	0.37
Water (throughput in gallons per well)[a]	269,693	199,924	188,827	311,457	85,107	116,514

[a] Water volumes do not account for water associated with hydraulic fracturing activities.

2.2.3 Hydraulic Fracturing and Management of Flowback Water

Because of the low permeabilities of shale formations, which limit the flow of NG within the formation, producers hydraulically fracture the formation to enable the flow of NG. This outcome is accomplished by pumping fracture fluid at a predetermined rate and pressure sufficient to create fractures in the target formation. The fracture fluid for shale formations is typically water based and consists of proppants, sand, or similarly sized engineered particles that maintain fracture openings once they have been established and the pumping of fracture fluid has ceased. Although we included the transportation and management burdens for water and flowback from hydraulic fracturing activities, we did not include the production and transportation burdens of proppants and other chemicals, because the small amounts of consumption involved would affect the results only minimally.

For this analysis, values for fracturing (or frac) fluid constituents were based upon fraccing data made available by Range Resources, which released frac fluid information for several of its Marcellus wells (Range Resources 2010a–c). Large volumes of water are required for drilling and fraccing activities. Typical volumes depend on the characteristics of the shale and are provided in Table 6.

TABLE 6 Typical Range of Water Requirements Per Well for Fraccing Activities by Shale Play (GWPC & ALL 2009, Mantell 2010b)

Shale Play	Typical Range of Frac Water Input per Well (gallons)
Barnett	2,300,000–3,800,000
Marcellus	3,800,000–5,500,000
Fayetteville	2,900,000–4,200,000
Haynesville	2,700,000–5,000,000

The total water input varies according to geology and drilling practices, with air drilling commonly practiced in the Marcellus and Fayetteville plays. While the constituents of a frac job will vary according to site conditions, the average concentrations of these constituents were extrapolated to other shale plays according to typical water use for a relatively similar frac in each play. The estimated components and amounts for frac jobs in the Marcellus are presented in Table 7.

TABLE 7 Estimated Fraccing Fluid Components According to Average Values from Selected Marcellus Wells (Range Resources 2010a–c)

Per Well	Amount	Unit
Water	4,614,556	gal
Sand	6,049,200	pounds
Friction Reducer (polyacrylamide, mineral oil)	1,843	gal
Antimicrobial Agent	1,316	gal
Glutaraldehyde	163	gal
n-alkyl dimethyl benzyl ammonium chloride	27	gal
Ethanol	3	gal
4,4-Dimethyloxazolidine	723	gal
3,4,4-Trimethyloxazolodine	47	gal
2-Amino-2-methyl-1-propanol	10	gal
Formaldehyde Amine	4	gal
Scale Inhibitor	454	gal
Sodium hydroxide	17	gal
Ethylene glycol	270	gal
Perforation Cleanup	409	gal
37% HCl	409	gal
Methanol	13	gal
Propargyl Alcohol	0.5	gal

Because of the relatively small amounts of chemicals per mmBtu, the life-cycle energy and emissions burdens of the proppants and components of fracturing fluids were not included. However, the energy and emissions burdens associated with fraccing and managing the flowback water were included.

Another component of fracturing a well is the management of flowback water. Flowback water is the water that is produced from the well immediately after hydraulically fracturing the well and before gas production commences. Outside of the Marcellus, flowback water is collected and typically disposed of through underground injection. Within the Marcellus region, however, flowback water is collected and typically reused in fraccing activities. Using average frac fluid volumes per well and assuming that water was transported both on- and off-site via truck, we determined the electricity and fuel requirements associated with hydraulic fracturing activities.

For the Marcellus, 95% of flowback was assumed to be recycled because of the long-distance transport requirements to dispose of the fluid via injection wells. For the other plays, where injection wells are located nearby, recycle rates were assumed to be 20% of flowback for the Barnett and Fayetteville plays and 0% for the Haynesville play (Mantell 2010a). The total volume of recycled fluid depends on the fraction of frac fluid that flows back up the well after hydraulic fracturing activities, which varies considerably among the different shale plays. For example, while the majority of the plays considered do not recover all of the hydraulic fracturing fluid during the flowback period, the Barnett shale typically yields a larger volume of flowback water than was used during hydraulic fracturing activities. Flowback rates, recycle rates, and distances required to transport and manage flowback water were based upon input from industry experts. The flowback fractions and the typical distances between water source, well site, and injection disposal well are summarized for each play in Table 8. The transportation burden associated with hauling recycled flowback to a well site is accounted for only as an input to avoid double counting as the burden associated with removal would be allocated to another well as input.

TABLE 8 Assumptions in Determining the Transportation and Management of Hydraulic Fracturing Fluids (Gaudlip et al. 2008; Mantell 2010a; Stinson 2008)

Parameter	Barnett	Marcellus	Fayetteville	Haynesville
Water volume per truck (gal/truck)	5,500	3,400[a]	5,500	5,500
Distance to transport freshwater to site (miles)	5	10	15	15
Distance to transport recycled fluid to site (miles)	2	5	5	5
Distance to transport fluid to disposal well (miles)	10	50	20	10
Flowback fraction	2.75	0.2	0.25	0.9
Recycled fraction	0.20	0.95	0.20	0.00

[a] Volume reported in Gaudlip et al. (2008). The smaller volume is an artifact of the terrain, which limits vehicle size in the Marcellus.

Diesel fuel consumption was determined according to the typical distances that water is trucked and accounted for trips to and from the well site. Distances will vary according to well location. It was assumed that truck fuel consumption was 5 miles per gallon (mpg) for a loaded truck and 7 mpg for an unloaded truck, as determined from Delorme et al. (2009) and Davis et al. (2010), which is consistent with GREET. To determine the electricity consumed by the pumps associated with injection for disposal, injection well parameters from Nakles et al. (1992) were used to determine pump energy as described in Geankoplis (1993) and the following equation:

$$Electric\ power\ input\ \ kW\ = \frac{Hgm}{\eta\eta_e 1000}$$

where H is the head of the pump in meters of fluid, g is the gravimetric constant 9.8 m/s^2, m is the flow rate in kg/s, η is the fractional efficiency, η_e is the electric motor drive efficiency, and 1000 is the conversion factor of W/kW. Table 9 presents both diesel fuel consumption and electricity consumption according to shale play.

TABLE 9 Fuel and Energy Requirements for the Management of Frac Fluid

Shale Play	Volume per Frac Job (gal/well)	Hydraulic Fracturing: Diesel Fuel Consumption (gal/well)	Fluid Management: Electricity Consumption (kWh/well)
Barnett	3,019,000	4,771	94,887
Marcellus	4,615,000	4,444	659
Fayetteville	3,523,000	4,063	10,066
Haynesville	3,803,000	5,689	48,891

2.2.4 Well Completions

After the well is drilled and constructed, the bottom of the hole must be prepared, production tubing must be run through the well, and the well must be perforated or hydraulically fractured as required. All of these steps are part of the well completion process. As shale gas wells require hydraulic fracturing, the fugitive methane emissions associated with completion of wells for shale are different from those estimated for conventional NG. Previous inventories were based on data for conventional wells only, and those emissions were assumed to be flared. To estimate emissions from conventional well completions, we are using the updated emission factor from the EPA of 0.71 metric tons CH_4 per conventional well completion (EPA 2010b). We divided this emission factor by our estimate of EUR. As mentioned above, the EUR was determined by dividing the conventional gas production by the total number of producing conventional gas wells in 2009 (EPA 2011, EIA 2011b). The total number of conventional gas producing wells was determined by multiplying the total number of wells reported by the EIA by the percent of conventional gas wells to total gas wells reported by the EPA (EPA 2011; EIA 2011b). To convert bulk gas to methane, we assumed a distribution according to natural gas production by state and average methane concentration (EIA 2010b; GTI 2001). The weighted average methane content derived by using this approach was determined to be 84.6%.

For conventional well completion emissions, Howarth et al. (2011) also cite the EPA (EPA 2010b). Howarth et al. (2011) converted to an NG emission factor assuming 78.8% methane content. The NG emission factor was then multiplied by the total well count in 2007 and divided by the total NG produced in 2007 to arrive at the percent of methane produced over the well life cycle. It is likely that the differences in approach and production year account for the differences in emissions between our study and Howarth et al. (2011). Nonetheless, conventional well emissions are significantly smaller than are those for unconventional wells.

The shale gas well completion emissions in this analysis are based on several EPA sources (EPA 2011, 2010a, 2010b). The estimate of CH_4 vented during shale gas well completions accounts for the additional time that venting occurs after hydraulic fracturing as the flowback water is collected prior to the commencement of gas production. The emission factors used by EPA are based on data from reduced emission completions (RECs) (EPA 2004b, 2007). RECs are practices and technologies that when implemented can reduce the amount of methane emitted during a well completion. From these data, which include both tight sand and shale plays, EPA calculated unmitigated completion emissions ranging from 700 to 20,000 thousand cubic feet (Mcf) with an average of 9,175 Mcf or 177 metric tons of methane per unconventional completion (assuming 78.8% methane content). Periodically during the productive life of a well, the well will need to be cleaned, have new production tubing installed, and will potentially be re-perforated or refractured. This maintenance process is referred to as a well workover. The same emission factor used for a well completion is assumed for a shale gas well workover, as the well would likely require additional hydraulic fracturing every 10 years (EPA 2010b).

This approach may lead to overestimation because wells without REC equipment will typically conduct flowback for a shorter time period than do REC wells. In contrast, the equipment used for RECs allows operators to carry out flowback for a longer period of time, permitting improved debris removal and well flow. Overestimation may also result from estimating flowback emissions according to initial production rates. This approach was evident in some Natural Gas STAR data as reported in Howarth et al. (2011) (Samuels 2010; Bracken 2008; EPA 2007, 2004b). Initial production rates are calculated following hydraulic fracturing and flowback. After hydraulic fracturing of a well, the flowback initially brings up mostly sand and frac fluids. As the sand and water are removed, the gas concentration increases. When the well builds to a high enough pressure, venting ceases and the gas can be directed to the gathering lines. Therefore, using the initial production rate for the entire flowback period significantly overestimates completion emissions. Howarth et al. (2011)'s high-end estimate for the range of completion emissions for the Haynesville Shale relied on initial production estimates from an industry report that highlighted several high-volume wells (Eckhardt et al. 2009). These researchers assumed that flowback would last 10 days as they did not have a reference for this play, and when multiplied by the initial production rate of approximately 24,000 Mcf/day for these high-producing wells, the resulting emissions might be overestimated. Emission factors associated with shale gas completions require further development to reduce the uncertainties involved. Accounting for flaring and reduction practices is discussed in Section 2.2.7, Methane Reductions from Natural Gas Recovery.

2.2.5 Liquid Unloadings and Miscellaneous Leakage and Venting

In addition to emissions associated with well completions and workovers, fugitive methane emissions also occur at the wellsite from liquid unloading activities, leaks, and miscellaneous venting. Liquid unloading is the process of removing liquids that gradually build up and block flow in wet gas wells. EPA significantly adjusted the emissions associated with liquid unloading as a result of data reported by the Natural Gas STAR Program (EPA 2010a). The unmitigated emission factor is based upon fluid equilibrium calculations and Natural Gas STAR Program data for two basins (EPA 2004b, 2006). EPA assumes that liquid unloadings apply only to conventional wells. Although the assumption is reasonable given that shale gas is typically a dry gas, some shale formations such as the Antrim and New Albany do produce water and may require liquid unloadings. EPA estimated the unmitigated emission factor by calculating: (1) the amount of gas needed to blow out the liquid, which is a function of well depth, casing diameter, and shut-in pressure; and (2) the amount of gas vented after the liquid has been blown out by using annual recovery data reported by operators utilizing automated plunger lift systems to remove liquids and capture gas. The number of unloadings for the two basins were 11 and 51, respectively, with an average of 31 unloadings per well per year. In addition, the original inventory work by Harrison et al. (1996) assumed that 41.3% of conventional wells require liquid unloading. As a result, the emission factor reported by EPA is 11 metric tons of CH_4 per year per well, which suggests that 26.7 metric tons of CH_4 are released per year per every well that requires liquid unloadings. Our unloading estimates are significantly higher than are those of Howarth et al. (2011), who estimated liquid unloadings from GAO (2010). The U.S. Government Accountability Office (GAO) estimates were based on 2006 estimates from the Western Regional Air Partnership, which determined emissions in part from surveying operators, as well as on 2008 estimates from EPA, which were developed prior to the methodological change.

The frequency of liquid unloadings will depend on the age of the well and will likely vary both between and within plays. According to EPA, liquid unloadings account for 50% of the unmitigated emissions for the NG production sector, and therefore, the absence of reliable data on the frequency of unloadings and their emissions creates a large degree of uncertainty for the conventional NG pathway (EPA 2010b). Thus, researchers — taking both variation in the frequency of liquid unloadings and the significant uncertainty stemming from limited testing into account — should further examine these emission factors.

For both shale and conventional wells, methane emissions can result from various on-site equipment (and practices), such as pneumatic devices, condensate tanks, and gathering compressors. Assuming that similar equipment would be located on site at both shale gas and natural gas wells and would perform similarly, we estimated the unmitigated emissions from these sources using two approaches. The first approach used EPA emissions for 2005 through 2009 and normalized them according to gross NG production data for the same time period. This approach estimated unmitigated emissions at 114 grams of methane per million Btu (lower heating value) of NG (EPA 2010b, 2011). The second approach relied on a report by GAO, which included EPA 2008 emissions data for federal onshore activities, and the Bureau of Land Management's 2008 estimate for federal onshore production of 3,106 Bcf, from which we derived an emission factor of 303 grams of CH_4 per million Btu of NG (GAO 2010; BLM 2010). We used these data points as the range for our distribution and the mean value as our Base Case.

In addition to estimating methane emissions from well equipment and practices, we examined CO_2 flaring and venting. According to data in EPA (2011), we estimated that flaring would emit 369 grams of CO_2 per million Btu of NG, while according to data provided in GAO (2010), we estimated that flaring would emit 538 grams of CO_2 per million Btu of NG. As NG also contains CO_2, vented emissions were estimated to be roughly 41 grams of CO_2 per million Btu of NG (EPA 2011).

Howarth et al. (2011) developed their methane emissions for well equipment leakage and venting from GAO and calculated an emissions leakage range between 0.3% (for best available technology) and 1.9% of NG produced (GAO 2010). Howarth et al. (2011) did not provide estimates of CO_2 emissions for flaring or venting.

2.2.6 Recovery Pipeline to Compression Station

Once the shale gas is produced, it is directed from the wells to the main pipeline — similar to the process used in conventional gas production. For both conventional and shale gas, four wells were assumed per square mile, although that number can vary according to site (GWPC and ALL 2009). Schedule 40 stainless steel was assumed for the pipeline for inventory purposes. Gas is collected (assumedly in a 4-inch diameter pipe) at the well pad and is then conveyed via an 8-inch diameter pipe to a gathering station that collects gas produced within a 4- to 6-mile radius. From the gathering station, the gas is conveyed into a 12-inch diameter pipe toward local compression stations, where the gas is processed and pressurized prior to delivery to the main pipeline. The compression station typically processes gas produced within a 10- to 20-mile radius. To determine the material and fuel allocations of the pipelines per mmBtu, the inventory was first allocated per well and then converted to mmBtu according to the EUR.

Several steps are involved in constructing and installing a pipeline. Although the steps can be run in parallel to reduce the total amount of time spent at a site, diesel-consuming equipment is required for each stage and can include hydraulic excavators or pipelayers. As GREET already contains inventory and emissions associated with the main trunkline (Wang 1999; He and Wang 2000), this analysis focused on the installation of the smaller pipelines that feed into the main line at the compression stations. Therefore, it was assumed that small-sized equipment would be used and that the engines would have a maximum of 120 hp according to equipment specifications (Caterpillar 2010). It was also assumed that the equipment would run at 70% capacity during an 8-hour work day, or at 23% capacity for 24 hours. Assuming that a diesel engine consumes fuel at a rate of 0.06 gal/hp/h (Radback Energy 2009), the fuel required to run one piece of equipment for pipeline construction at specified capacity and horsepower levels results in a daily fuel consumption rate of 90.5 gal/day (340.9 liters [L]/day) according to the following equation:

$$\text{Fuel Consumption [gal/day]} = 0.23\text{[h/h]} \times 120\text{[hp]} \times 0.06\text{[gal/hp}-\text{h]} \times 24\text{[h/day]}$$

Pipelines are typically installed in a series of steps. After a right of way is established, excavators create a trench. Sections of pipe are laid along the length of the trench. At this point, the pipe is bent and welded to form a continuous piece and conform to the contours of the trench. After being treated with a protective coating, the pipe is lowered into the trench and then backfilled with soil (Kern River Gas Transmission Company 2010). For the 2- to 4-inch diameter pipe, it was assumed that approximately 1,000–2,000 ft could be installed per day. For 6-inch diameter pipe, it is assumed that approximately 1,000 ft of pipe could be installed per day. For 12-inch diameter pipe, approximately 500 ft of pipe/day could be installed. These assumptions were used to calculate the total number of days required to install the pipelines from the wells to the gathering stations and to the compressor station. Table 10 presents the material and fuel requirements for installing the pipelines from the wellhead to the compression station.

TABLE 10 Average Material and Energy Requirements for Pipeline per mmBtu of Natural Gas

	Shale Estimate per mmBtu				Conventional Estimate per mmBtu	
Inventory	**Barnett**	**Marcellus**	**Fayetteville**	**Haynesville**	**Low Estimate**	**High Estimate**
Steel (Mg/mmBtu)	7.09E-05	4.17E-05	7.30E-05	2.99E-05	6.92E-04	1.50E-04
Diesel Fuel (gal/mmBtu)	2.68E-04	1.58E-04	2.76E-04	1.13E-04	2.62E-03	5.68E-04

2.2.7 Methane Reductions from Natural Gas Recovery

One impetus for the EPA to revise the GHG emissions estimates was the realization that the methane reductions reported by the Natural Gas STAR Program were larger than the total unmitigated emissions calculated using its previous methodology. In our analysis, the unmitigated emission factors for each activity associated with natural gas recovery were adjusted to represent real-world conditions according to EPA aggregated emissions reduction data. However, although the aggregated emissions data from EPA (2011) show reductions from both the Natural Gas STAR Program and the National Emission Standards and Hazardous Air Pollutants (NESHAP) regulations, details were not provided on emission reductions by activity. Therefore, we examined data from the Natural Gas STAR Program to estimate emissions reductions for each activity (EPA 2010a).

We grouped the recovery sector technologies listed in Natural Gas STAR documentation and their respective CH_4 reductions into three categories: (1) unconventional well completions, (2) conventional liquid unloadings, and (3) well equipment venting and leakage. As the Natural Gas STAR Program only provides partially aggregated results to protect confidential business information, the reduction data lack details. Through background information provided by EPA, we separated most of the reductions from RECs and technologies based on liquid unloading and thus were able to estimate the equipment emissions (Hanle 2011). For example, as a category, RECS had the largest emissions savings reported by Natural Gas STAR Program partners, with savings ranging from 33% to 56% of the reductions from the production sector for each year from 2005 to 2009.

The NESHAP regulations set standards to reduce emissions of hazardous air pollutants, although these regulations have a secondary benefit in reducing methane emissions. In EPA GHG inventory estimates, emissions from flaring are included under NESHAP reductions, as states such as Wyoming require that vented emissions from well completions and workovers be flared. EPA assumed that in states without these regulations, such as Texas, Oklahoma, and New Mexico, no flaring would occur. EPA estimated that approximately 51% of the total number of unconventional wells in Texas, Oklahoma, New Mexico, and Wyoming were located in Wyoming and required flaring (EPA 2010b). It was then extrapolated that 51% of all unconventional completions are required to be flared in the United States.

The EPA conducts quality assurance and control checks of the Natural Gas STAR reductions prior to incorporating them into its inventory estimates. While the emissions reductions from Natural Gas STAR and NESHAP are considerable at approximately 30% of the unmitigated emissions in 2009, detailed information is limited. To address some of the uncertainty in these estimates, we developed distribution functions for these reductions. For shale completions, most of the uncertainty was attributable to flaring assumptions: thus, our low-reduction reduction scenario assumed only reductions from the Natural Gas STAR program (38%); while our Base Case assumed a small amount of flaring based on the number of wells in Wyoming, along with the Natural Gas STAR reductions (41%); and finally, our high-reduction reduction scenario assumed the same amount of flaring as the EPA did, along with Natural Gas STAR reductions (70%) (EPA 2010a). For conventional wells, there was significant uncertainty associated with liquid unloadings as the Natural Gas STAR accounting practices do not report emissions reduction projects that have exceeded an agency-prescribed sunsetting period, even though those emissions are still being reduced in practice. Therefore, we developed a low-reduction reduction scenario for liquid unloadings based on reported Natural Gas STAR reductions (8%) and a high-reduction reduction scenario where we adjusted for the sunsetting period (15%), while our Base Case is the average of those two. For the third category, well equipment, which applies to both shale gas and conventional gas recovery, we developed a low-reduction reduction scenario based on Natural Gas STAR and NESHAP reductions (18%) and a high-reduction reduction scenario in which we adjusted for the sunsetting period (37%), while our Base Case is the average of those two.

2.3 Data for Natural Gas Processing, Transmission, Storage, and Distribution

Downstream from the recovery stage, NG passes through a processing stage in which undesirable elements of raw gas (such as NG liquids) are removed. The processed NG enters the transmission and storage (T&S) stage, in which NG is moved long distances through high-pressure pipelines. Compressor station facilities, where turbines and compressors force the gas through the large-diameter pipes, dot the transmission pipeline network. At times, NG is delivered directly from the transmission network to industrial customers. Alternatively, the gas may be stored underground or liquefied and stored in aboveground tanks. Before residential and commercial customers access the gas, its pressure is reduced and it travels through the distribution network of low-pressure pipes that are often underground. Pipeline construction for distribution is not included, as it is assumed to exist already and would be identical for shale gas and conventional natural gas. Table 11 details key activities that result in fugitive methane emissions from natural gas processing, transmission and storage, and distribution.

TABLE 11 Selected Activity Factors for the Processing, Transmission and Storage, and Distribution Sectors

Sector	Sample Activity Data
Processing	• Processing plants • Centrifugal compressors • Acid gas removal vents (CO2 source) • Blowdowns/venting
Transmission and Storage	• Reciprocating and centrifugal compressors • Dehydrator vents • Pneumatic devices
Distribution	• Miles of mains and services by material (iron, steel, plastic, copper) • Metering and regulating stations • Residential customer meters

For natural gas processing, transmission and storage, and distribution, it is assumed that shale gas would be treated in a manner similar to that of conventional natural gas. As a result, the existing pathway in GREET, as described in Wang et al. (2007), Brinkman et al. (2005), Wang (1999), and Wang and Huang (1999), was used, and the GHG emissions associated with these stages were updated, as appropriate. To calculate methane leakage emissions from NG processing, T&S, and distribution sectors, we divided the average methane emissions from these sectors by the average production of NG for this same time period (EPA 2011; EIA 2011b). If NG exports were significant during this time period, this approach could underestimate emissions in the T&S and distribution sectors. Exports, however, were 4% of production in 2009, the year with the greatest volume of NG exports in the period between 2005 and 2009 (EIA 2011b). The use of NG production volume in the calculation of the emission factors is therefore reasonable.

We also examined vented CO_2 emissions from acid gas removal (AGR) in the processing sector. These emissions account for about 50% of the total GHG emissions from the processing sector (EPA 2010b). The results for these sectors include CH_4 emission factor distributions based on the uncertainties provided in Harrison et al. (1996). For the low and high AGR vent emission factors, we assumed an uncertainty of plus or minus 30% based on EPA's discussion (2010b).

Significant differences exist between our analysis of these sectors and that of Howarth et al. (2011). For the processing sector, Howarth et al. (2011) used the mean emissions facility-level gas-processing emission factor for fugitive CH_4 of 0.19% as provided in the American Petroleum Institute's (API's) Compendium to estimate processing sector emissions (Shires et al. 2009). API developed a range of 0% to 0.19% for these emissions, with the lower bound of zero representing wells that produce pipeline-ready gas that needs no processing. API did not explicitly estimate CO_2 emissions from AGR) vents in their analysis. Shires et al. (2009) use data from the 1990s, such as the 1993 volume of total gas processed; they state that the uncertainty associated with the reported emission factor is plus or minus 82.2%, placing the emission factor between 0.03% and 0.35% of total gas processed.

In their analysis, Howarth et al. (2011) did not distinguish between the T&S and distribution sectors, whereas our analysis breaks out emission factors for these sectors. Table 12 illustrates that the derivation of the low value (1.4%) from the analysis by Howarth et al. (2011) is an estimate of emissions from the Russian NG transmission and distribution network (Lelieveld et al. 2005). The estimate of NG leakage in the Russian T&S and distribution sectors is likely an overestimate of emissions for these sectors in the United States for several reasons. First, an examination of emissions suggests that the activity and emission factors for the two systems will be different. Specifically, compressor emissions in the Russian T&S sector indicate that the emission factor for this sector in Lelieveld et al. (2005) is likely too high to be representative of T&S sector emissions in the United States. Second, the estimate of leakage from the distribution sector was based on outdated U.S. emissions rates from 2002 and earlier. In the United States, this sector has seen emissions decrease significantly by 13% between 1990 and 2009 with the adoption of lower-emitting technology, such as plastic piping (EPA 2011).

TABLE 12 Derivation of Lelieveld et al.'s (2005) Estimate of Natural Gas Losses during Transmission and Distribution in Russia

Natural Gas Sector	Methane Loss (% of Total Throughput)	Data Source
Domestic Russian transmission	0.7 (0.4–1.6)	Field measurements in Russia
Domestic Russian distribution	0.5–0.8	Assumed that the percentage of produced NG leaked in the Russian and U.S. distribution networks would be roughly equivalent
Domestic Russian gas spills at wells	0.1 ± 0.04	Re-evaluation of data from Dedikov et al. (1999)
Total	1.4 (1.0–2.5)	

The high value (3.6%) that Howarth et al. (2011) cite for the T&S and distribution sectors is the average of two years' estimates of lost and unaccounted for gas (LUG) in Texas (Percival 2010). LUG is an accounting term for the difference between the volume of gas produced and that sold. Percival (2010) points out drawbacks to using LUG as an estimate of leaked NG. First, differences in the accuracy of measurements between wellhead and process plant devices, compounded by changes in volume due to ambient temperature variations, introduce discrepancies between measured volumes of produced and processed gas. In addition, when NG is processed, high-value liquids and impurities are separated, further widening the gap between the volumes of gas measured at the wellhead and post processing. Finally, LUG calculations can include NG produced at the wellhead that is used as a process fuel in equipment used for gathering and processing, thereby depleting the amount of gas that ultimately is sold. Howarth et al. (2011) assert that these factors (except gas theft) are randomly distributed and therefore will not yield a high or low bias in estimates of NG leakage. However, others assert that LUG will consistently overestimate actual emissions to the atmosphere (Percival 2010; Kirchgessner et al. 1997). In summary, LUG is not a reliable means of quantifying NG leakage in the T&S and distribution sectors.

2.4 GREET Life-Cycle Analysis

Since 1996, Argonne National Laboratory has been developing and using the GREET model to examine the life-cycle energy and emissions effects of different transportation fuels and advanced vehicle technologies (Argonne 2011; see also http://greet.es.anl.gov/main). To explore energy and emissions issues associated with shale gas and conventional gas, we used the GREET model to develop a shale gas pathway, to estimate up-to-date life-cycle GHG emissions of shale and conventional gas energy options, and to quantify the uncertainties in the estimated GHG emissions of both technologies.

With the parametric assumptions incorporated into the GREET model, we produced life-cycle GHG emissions for the energy pathways with three functional units. With the distribution functions as described in Section 2.2, we used GREET's stochastic modeling capability to generate results with distributions.

2.4.1 Treatment of Emissions from Early 1990s Natural Gas Systems to Current Systems

Key emission factors for NG systems in previous GREET versions were based on Harrison et al. (1996), which examined the NG system found in the early 1990s. As NG use in the United States expands, certain subsystems (such as NG wells and storage facilities) expand, but other subsystems (such as NG transmission and distribution pipelines) may remain at the same size and extent. To address this situation, previous input parameters to GREET implicitly assumed that only production and processing capacity would be added to the NG system to handle the increased demand between early 1990s and now. The T&S and distribution sectors, however, had extra capacity and would not be expanded. As a result, emission factors from Harrison et al. (1996) were modified prior to use in GREET, as outlined in Table 13.

TABLE 13 Comparison of Current GREET Emissions Factors with Harrison et al. (1996)

	CH_4 Emissions: Percent of Volumetric Natural Gas Produced		New GREET Values	
Sector	Harrison et al. (1996)	Existing GREET Values	Conventional NG	Shale Gas
Production	0.38	0.35	1.93	1.19
Processing	0.16	0.15	0.15	0.15
Transmission	0.53	0.27	0.39	0.39
Distribution	0.35	0.18	0.28	0.28

As presented in Section 2.2, we updated CH_4 emission factors for NG, and as a result (see Table 13), the emission factors for the T&S and distribution sectors are markedly higher than they are in previous GREET analyses.

2.4.2 End-Use Efficiencies

We included the end-use efficiencies for both power plants and vehicles to estimate the life-cycle GHG impacts of the fuels in specific applications. For NG power plants, we estimated that conventional NG boilers are 33% efficient and NG combined cycle (NGCC) power plants are 47% efficient, according to data calculated from EIA Form-906 "Power Plant Report" (EIA undated). For coal power plants, efficiencies were estimated at 34% for conventional pulverized coal boilers and 42% for supercritical boilers, according to IEA (2006).

For a passenger car, we assumed a fuel economy of 29 miles per gallon gasoline-equivalent (mpgge). We assumed that a compressed natural gas (CNG) car with similar performance would have a fuel economy penalty of 5% (on an mpgge basis) primarily because of the weight penalty of onboard CNG storage cylinders. We developed a distribution function for the relative fuel economy of the CNG car as compared to the gasoline car. For the high estimate, it was assumed that the CNG car would have the same fuel economy. The low estimate assumed that the CNG car would have a 10% reduction as compared to the gasoline car.

Several studies have examined the fuel consumption of NG and diesel transit buses. On average, CNG-fueled transit buses have a fuel economy 20% lower than that of diesel-fueled buses (Adams and Home 2010; Barnitt and Chandler 2006; Chandler et al. 2006). This finding is attributable to the low thermal efficiency of a spark-ignited engine when operating at low speed and load as compared to a compression-ignition diesel engine (Barnitt and Chandler 2006). However, it has been argued that, because of equipment and strategies employed to meet the EPA's 2010 heavy-duty engine emissions standards, the fuel efficiency benefit of diesel buses has been reduced. According to Cummins-Westport (in Adams and Home 2010), the 8.1-liter ISL G NG engine can either match an equivalent diesel engine in fuel economy or have a fuel economy that is 10% lower depending on the duty cycle. For our analysis, CNG transit buses would have a 20% reduction in fuel economy for our low estimate and a 10% reduction in fuel economy for our high estimate. The mean value was assumed to be our Base Case. A summary of our end-use efficiency assumptions is shown in Table 14.

TABLE 14 End-Use Efficiency Assumptions for GREET Simulations (mean values with ranges in parentheses)

Power Plant	Units	Values	Sources
NGCC efficiency	%	47 (39–55)	Average of 2007 and 2008 data based on Form EIA 906, "Power Plant Report"
NG boiler efficiency	%	33.1 (33.0–33.5)	Brinkman et al. 2005
Supercritical Coal Boiler efficiency	%	41.5 (39.0–44.0)	IEA 2006
Subcritical Coal Boiler efficiency	%	34.1 (33.5–34.4)	Brinkman et al. 2005
Vehicles			
Gasoline passenger car – fuel economy	Miles per gallon – gasoline equivalent	29 (23–32)	Honda Civic LX, MY 2007-11; assumed high 10% better, low 20%; based on driving behavior (DOE 2011).
CNG passenger car – fuel economy	Ratio of gasoline car	0.95 (0.9–1.0)	Mid-range value based on GREET 5% reduction; high value assumed fuel economy can reach same level as gasoline (Wang 1999); low value based on 1990s CNG vehicle models.
Diesel transit bus – fuel economy	Miles per gallon – diesel equivalent	3.5 (3.0–3.7)	Mid-range value is based on Davis et al. (2010). Transportation Energy Data Book Ed. 29 assumed that high value is 5% better, low value 15% worse; based on driving behavior and vehicle technologies.
CNG transit bus – fuel economy	Ratio of diesel bus	0.85 (0.80–0.90)	Low value is with 20% reduction based on numerous transit bus studies; high value is based on Adams and Home (2010); mid-range value is average of high and low.

2.4.3 Greenhouse Gas Global Warming Potentials

Global warming potential (GWP) provides a simple measure to compare the relative radiative effects of various GHG emissions. The index is defined as the cumulative radiative forcing between the time a unit of gas is emitted and a given time horizon, expressed relative to that for CO_2. When comparing the emissions impacts of different fuels, researchers must choose a time frame for comparison. The Intergovernmental Panel on Climate Change (IPCC) calculates GWPs for multiple time horizons, such as 20-, 100-, and 500-year time frames. The IPCC recommends using GWPs for a 100-year time horizon when calculating GHG emissions for evaluating various climate change mitigation policies. When using a 20-year timeframe, the effects of methane are amplified as it has a relatively short perturbation lifetime (12 years), whereas CO_2 can last in the air for a long time. Howarth et al. (2011) use results from a recent study by Shindell et al. (2009), whereas our analysis relies on the IPCC's current, published results (IPCC 2007). Table 15 presents the GWPs that we used in comparison to those used by Howarth et al. (2011).

TABLE 15 Global Warming Potentials of Greenhouse Gases

	100-Year GWPs			20-Year GWPs			
	CO_2	CH_4	N_2O	CO_2	CH_4	N_2O	Source
GREET	1	25	298	1	72	289	IPCC 2007
Howarth et al. 2011	1	33	Not used	1	105	Not used	Shindell et al. 2009

3 RESULTS AND DISCUSSION

The life-cycle GHG emissions of shale and conventional NG were evaluated according to three functional units —grams of CO_2 equivalent per kilowatt-hour produced (gCO_2e/kWh), grams of CO_2 equivalent per vehicle mile driven ($gCO_2e/mile$), and grams of CO_2 equivalent per megajoule produced (gCO_2e/MJ) — over two GWP time horizons (i.e., 100-year and 20-year horizons). The results are presented and the impact of parameter uncertainty for both natural gas pathways is discussed.

3.1 GHG Emissions by End Use

When compared to the coal pathway, NG pathways show life-cycle GHG benefits on an average basis for the 100-year time horizon, as shown in Figure 3. When using GWPs for the 20-year time horizon, the emission benefits for the NG pathways are diminished (also shown in Figure 3). Only for the worst case of an NG boiler under a 20-year GWP time horizon do the emissions approach (in the case of shale) or exceed (in the case of conventional NG) a supercritical coal power plant.

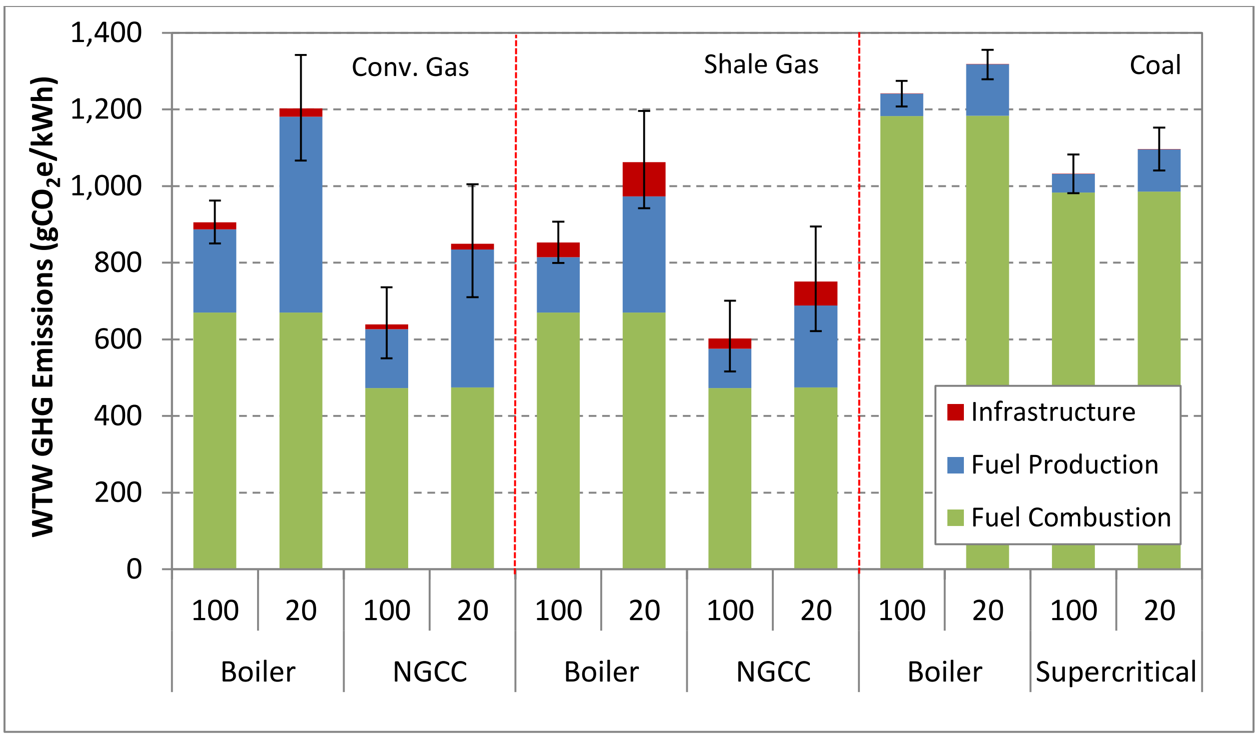

FIGURE 3 Life-Cycle GHG Emissions per kWh of Electricity Produced. Two time horizons — 100-year and 20-year — are considered (note: WTW = well to wheels, NGCC = natural gas combined cycle).

Figure 4 illustrates emissions in gCO_2e per mile for passenger cars. Considering a 100-year GWP horizon, there is no statistically significant difference in well-to-wheels (WTW) life-cycle GHG emissions among fuels on a vehicle-mile-traveled (VMT) basis. The GHG emissions for CNG cars are 3% lower for NG and 8% lower for SG than are those of gasoline cars in the 100-year time horizon. When considering a 20-year GWP horizon, however, conventional NG has a greater WTW life-cycle GHG impact than does gasoline. The emissions of CNG cars are higher by 25% for conventional NG and by 12% for shale NG, on average.

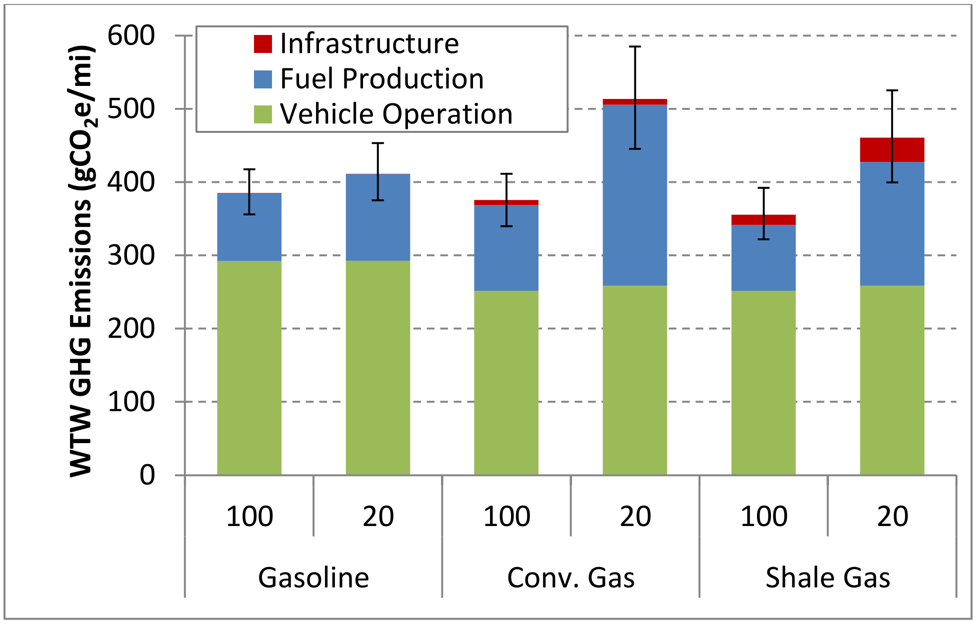

FIGURE 4 Well-to-Wheels Life-Cycle GHG Emissions per VMT – Passenger Car. Two time horizons — 100-year and 20-year — are considered.

The GHG emissions per VMT for transit buses are illustrated in Figure 5. The emissions per VMT for CNG transit buses are not statistically different from those of diesel buses with a 100-year GWP horizon. However, when considering a 20-year GWP horizon, CNG buses emit significantly more GHGs than do their petroleum-fueled counterparts, with emissions that are 34% higher for conventional NG and 20% higher for shale NG. To reduce GHG emissions, CNG buses will need to exceed our Base Case fuel economy assumptions.

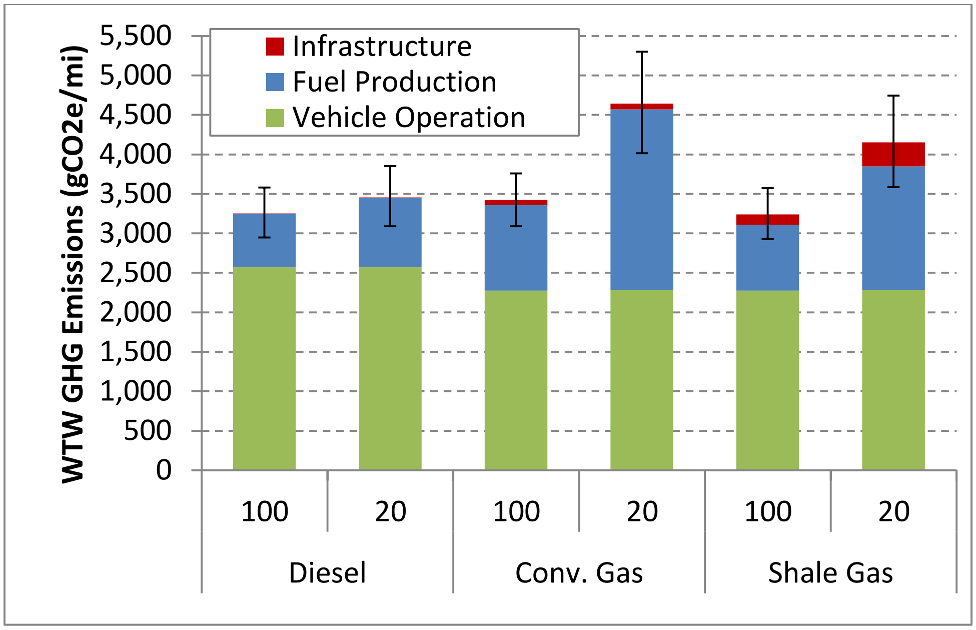

FIGURE 5 Well-to-Wheels Life-Cycle GHG Emissions per VMT – Transit Bus. Two time horizons — 100-year and 20-year — are considered.

3.2 Detailed Breakdown of GHG Emissions for Fuel Pathways

Figure 6 presents the results for the NG pathways in terms of gCO_2e/MJ. For both NG pathways, the emissions from direct fuel combustion are the largest contributors to life-cycle GHG emissions. Shale gas shows fewer GHG emissions than does conventional NG per MJ. This result is mainly attributable to the large CH_4 emissions associated with liquid unloadings and the lower EUR for a conventional NG well. The further breakdown of upstream and infrastructure emissions for the pathways enables examination of the relative importance of CH_4 leakage and CO_2 venting and flaring. For NG pathways, CH_4 venting and leakage during NG recovery operations are the largest upstream GHG emissions source. Liquid unloadings are a key factor for conventional NG, whereas completion and workover emissions are significant for shale gas. GHG emissions associated with materials and fuels for infrastructure are almost negligible in terms of the life-cycle emissions. The chart also shows the relative uncertainties for each pathway based on our stochastic simulations.

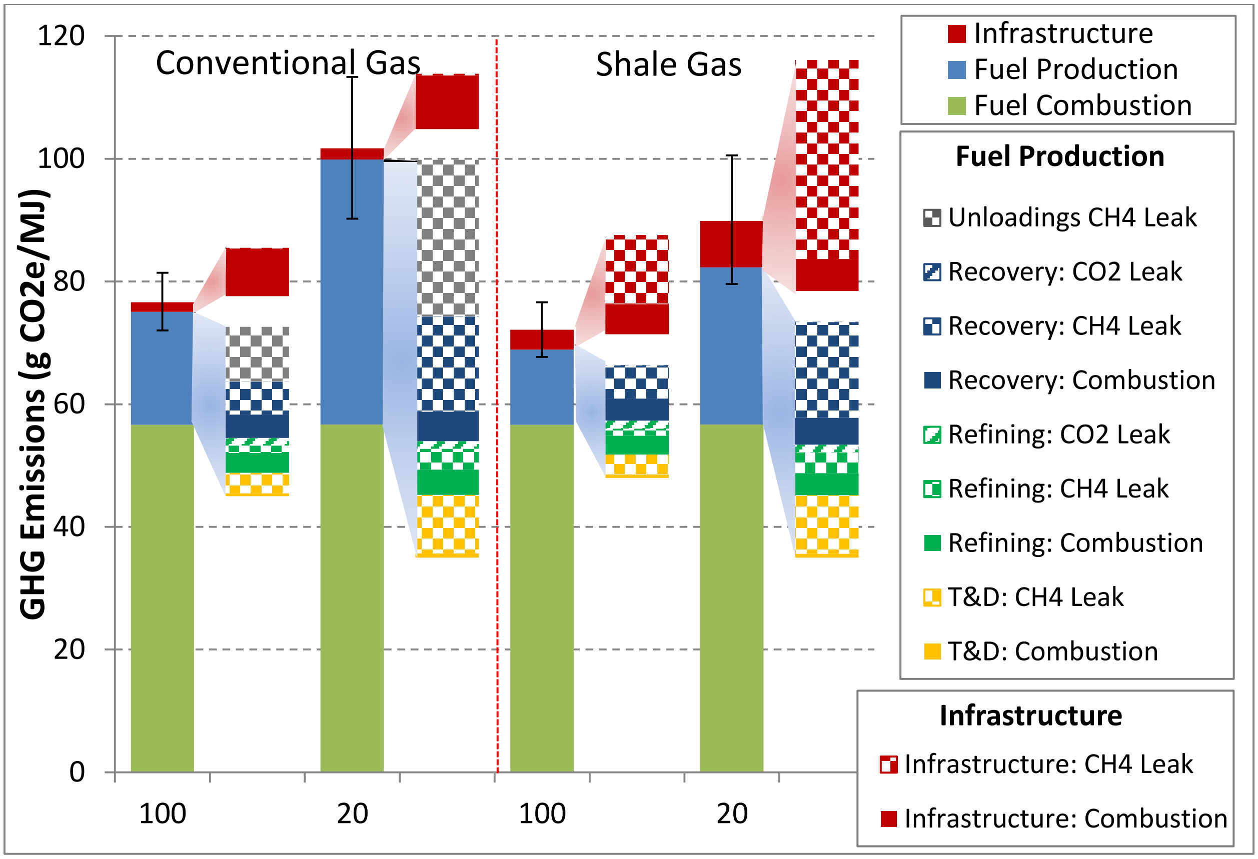

FIGURE 6 **Life-Cycle GHG Emissions per MJ of Fuel Produced and Combusted for Both 100-year and 20-year GWPs**

3.3 Examination of Uncertainty of Key Parameters with Respect to Life-Cycle Emissions

With CH_4 venting and leakage during NG recovery operations serving as the largest upstream GHG emissions sources and with liquid unloadings and EUR significantly contributing to differences in conventional and shale NG emissions, a sensitivity analysis was performed to examine the effect of the uncertainty of key parameters on the life-cycle emissions of NG and SG. The following "tornado" charts (Figure 7 and Figure 8) present results of our sensitivity analysis of key parameters affecting life-cycle GHG results for NG and SG pathways.

Considering only the conventional NG tornado charts, it is clear that CH_4 venting during liquid unloadings contributes the most uncertainty to our GHG emissions estimates under both time horizons. The next most significant parameter is CH_4 venting from well equipment. The large uncertainty is attributable to the wide range in the number of unloadings required for conventional wells and the subsequent emissions resulting from this activity. As the GWP of CH_4 is much larger under the 20-year time horizon than it is under the 100-year time horizon, the impact of the CH_4 venting during liquid unloading is greater under the former.

The shale gas tornado charts show trends similar to those of the conventional NG tornado charts outside of liquid unloadings as it is assumed the unloadings are not to be required for shale gas wells (EPA 2010). The other major difference between the two pathways (as previously noted) is that the completion and workover emissions associated with shale gas wells are much more significant than are similar emissions associated with conventional NG. However, completion and workover emissions have only moderate impacts on the uncertainty of life-cycle emissions, although the impacts are more pronounced under the 20-year time horizon. Under both time horizons, uncertainties in CH_4 venting from well equipment shows the largest impact on life-cycle GHG emissions for the shale NG pathway as the difference between the estimates from EPA (2011) and GAO (2010) are significant.

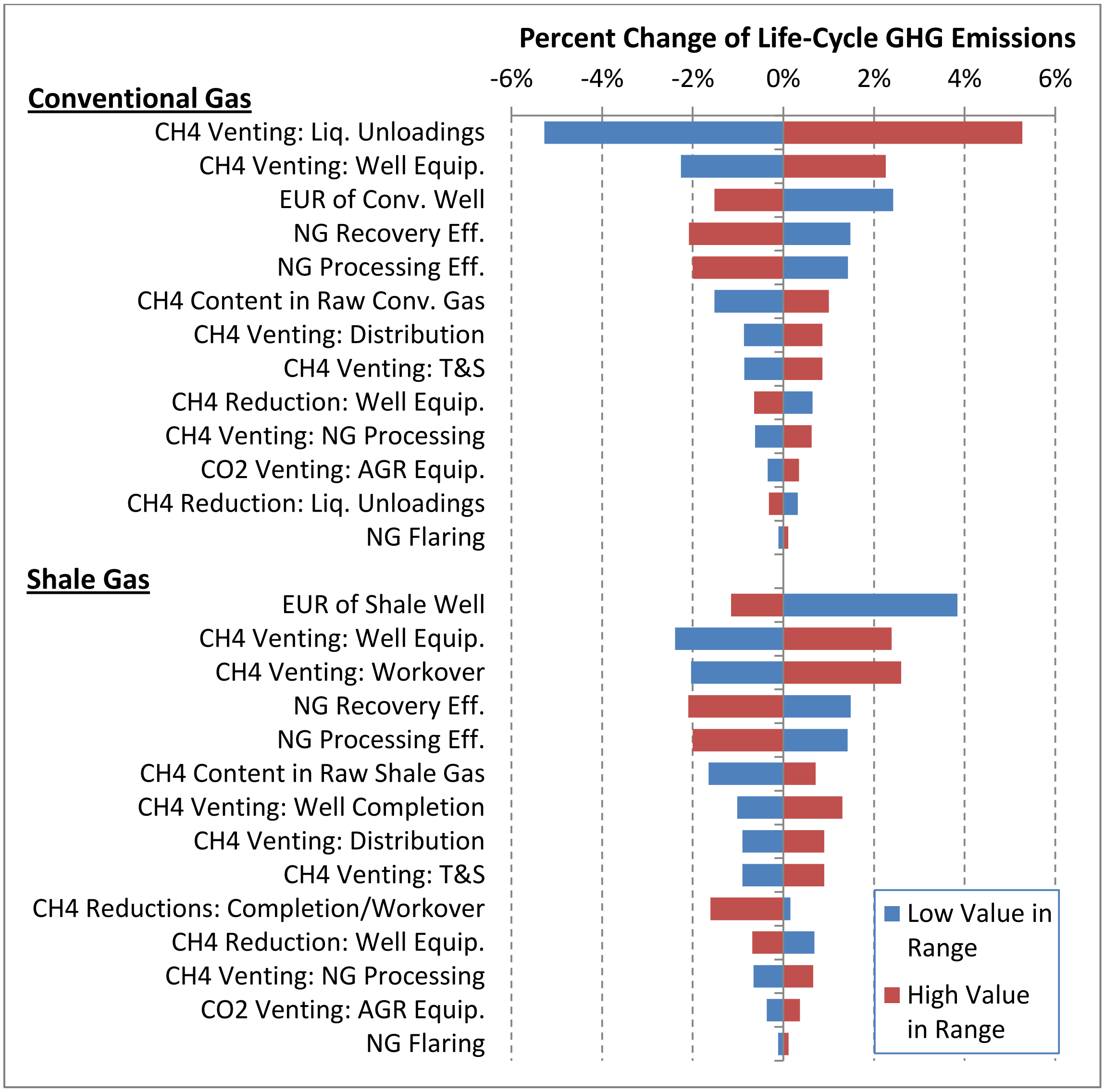

FIGURE 7 Sensitivity Analysis Results for Shale and NG Pathways (100-Year Time Horizon)

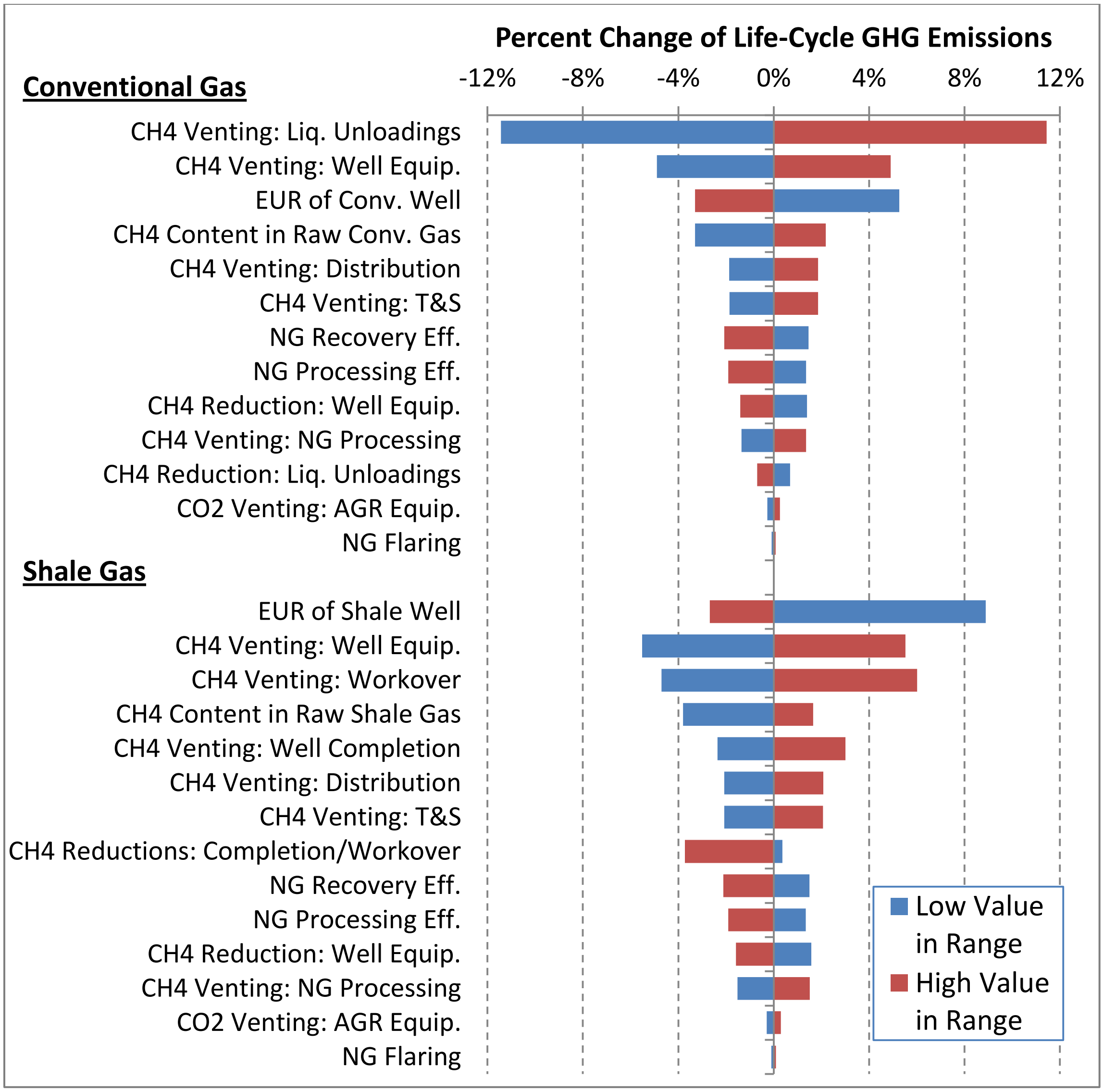

FIGURE 8 Sensitivity Analysis Results for Shale and NG Pathways (20-Year Time Horizon)

4 SUMMARY AND IMPLICATIONS

The analysis demonstrates that upstream CH_4 leakage and venting are key contributors to the upstream emissions of the NG pathway. These emissions can significantly reduce the benefits of producing NG as compared to coal or petroleum. The fact that only limited data have been available for several key issues has resulted in significant changes to EPA's GHG inventory estimation and some erroneous conclusions. More reliable and diverse data will aid the evaluation of the role of natural gas in the U.S. energy supply.

Specifically, for conventional wells, the volume of gas vented during liquid unloadings needs to be calculated for the various technologies that are employed on-site to remove liquids. Furthermore, a survey of the prevalence of each technology would provide much greater certainty to these emissions estimates. Such a survey could also examine what percentage of conventional NG and shale wells require liquid unloadings, as not all wells undergo this process. Given that the number of unloadings required over the lifetime of the well causes significant uncertainty, this factor should be examined in detail. These data could help researchers differentiate the unloading practices in different plays or geologic formations, as well as in different wells within the same play. A temporal evaluation to determine the number of unloadings required as a function of the age of the well would also provide relevant information when trying to create an inventory of these emissions. Flaring practices should also be examined for liquid unloading operations by both state regulations and industry practices.

For shale gas wells, the volume of gas vented during completions and workovers needs to be examined with and without RECs. This examination will improve understanding of the quantity of fraccing fluids and natural gas that are produced during the flowback period and the variability of the volume of fluid and gas that flow during that time. In addition to emissions associated with completions and workovers, the estimated number of workovers required during the expected lifetime of a shale gas well needs further examination. The decision to rework a well will be based on a number of factors that affect the economics of the well, including the age of the well, the expected improvement in NG production after workover, and the wellhead price of NG. Moreover, greater transparency is needed to aid in identifying the percentage of wells that are employing emissions-reduction practices. This identification includes completions and workovers implementing REC technologies and flaring practices for wells both with and without RECs. Such information could be gathered by examining state regulations and industry practices and could provide greater certainty regarding the emissions from shale gas. Finally, as the NG industry gains more experience with SG production through the lifetime of the well, the accuracy of EUR projections will hopefully improve.

Environmental management and GHG emissions reduction strategies need to be exercised in large-scale operation for shale and conventional NG to reduce the environmental and energy burdens associated with producing these fuels. The voluntary partnership of the natural gas industry and EPA under the Natural Gas STAR Program has helped reduce CH_4 emissions; however, further efforts could be undertaken to extend the application of emissions-reduction projects across the industry, develop new mitigation measures, and address the remaining environmental issues associated with natural gas production and transmission.

This page intentionally left blank.

5 REFERENCES

Adams, R., and D.B. Home, 2010, *Compressed Natural Gas (CNG) Transit Bus Experience Survey — April 2009–April 2010*, NREL/SR-7A2-48814, National Renewable Energy Laboratory: Golden, Colo.

Argonne (Argonne National Laboratory), 2011, Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model. Available at: http://greet.es.anl.gov/ (accessed June 1, 2011).

Barnitt, R., and K. Chandler, 2006, *New York City Transit (NYCT) Hybrid (125 Order) and CNG Transit Buses*, NREL/TP-540-40125, National Renewable Energy Laboratory: Golden, Colo.

BLM (U.S. Bureau of Land Management), 2010, MCF of Natural Gas Produced Yearly. Available at: http://www.blm.gov/pgdata/etc/medialib/blm/wo/MINERALS__REALTY__AND_RESOURCE_PROTECTION_/energy/oil___gas_statistics.Par.92178.File.dat/chart_2009_12.pdf. (accessed May 25, 2011).

Bourgoyne, A.T., K.K. Millheim, M.E. Chenevert, and F.S. Young, 1991, *Applied Drilling Engineering*, Society of Petroleum Engineers: Richardson, Texas, p. 301.

Bracken, K., 2008, *Reduced Emission Completions in DJ Basin and Natural Buttes*, Natural Gas STAR Producer's Technology Transfer Workshop, Rock Springs, Wyo., May 1.

Brinkman, N., M. Wang, T. Weber, and T. Darlington, 2005, *Well-To-Wheels Analysis of Advanced Fuel/Vehicle Systems — a North American Study of Energy Use, Greenhouse Gas Emissions, and Criteria Pollutant Emissions*; Argonne, IL.

Caterpillar, 2010, *315DL Hydraulic Excavator*. Available at: http://xml.catmms.com/servlet/ImageServlet?imageId=C414764 (accessed August 2, 2011).

Chandler, K., E. Eberts, and M. Melendez, 2006, *Washington Metropolitan Area Transit Authority: Compressed Natural Gas Transit Bus Evaluation*, NREL/TP-540-37626, National Renewable Energy Laboratory: Golden, Colo.

Chesapeake Energy, 2010, *Investor Presentation*, 2010 Institutional Investor and Analyst Meeting, Oklahoma City, Okla., Oct. 13.

Davis, S.C., S.W. Diegel, and R.G. Boundy, 2010, *Transportation Energy Data Book: Edition 29*, Oak Ridge National Laboratory, ORNL-6986.

Dedikov, J.V., G.S. Akopova, N.G. Gladkaja, A.S. Piotrovskij, V.A. Markellov, S.S. Salichov, H. Kaesler, A. Ramm, A. Müller von Blumencron, and J. Lelieveld, 1999, "Estimating Methane Releases from Natural Gas Production and Transmission in Russia," *Atmospheric Environment* 33, 3291–3299.

Delorme, A., D. Karbowski, R. Vijayagopal, and P. Sharer, 2009, *Evaluation of Fuel Consumption Potential of Medium and Heavy Duty Vehicles through Modeling and Simulation*, Report to the National Academy of Sciences. Available at: http://www.autonomie.net/docs/6%20-%20Papers/nas_mediumheavyduty_2009.pdf (accessed August 1, 2011).

DOE (U.S. Department of Energy), 2011, *Fuel Economy,* Office of Energy Efficiency and Renewable Energy. Available at: http://www.fueleconomy.gov/ (accessed May 25, 2011).

Eckhardt, M., B. Knowles, E. Maker, and P. Stork, 2009, *IHS U.S. Industry Highlights*, Houston, Tex., Feb–Mar.

EIA (U.S. Energy Information Administration), 2011a, *Annual Energy Outlook 2011,* DOE/EIA-0383(2011). Available at: http://www.eia.gov/forecasts/aeo/pdf/0383(2011).pdf (accessed November 21, 2011).

EIA, 2011b, *U.S. Natural Gas Summary: Production*. Available at: http://www.eia.gov/dnav/ng/ng_sum_lsum_dcu_nus_a.htm (accessed June 1, 2011).

EIA, 2009, *Shale Gas Plays, Lower 48 States*. Available at: http://www.eia.doe.gov/oil_gas/rpd/shaleusa2.pdf (accessed December 15, 2010).

EIA, undated, Form EIA-906: Power Plant Report, 2007–2008. Available at: http://www.eia.gov/cneaf/electricity/page/eia906_920.html (accessed May 12, 2011).

EPA (U.S. Environmental Protection Agency), 2011, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2009,* EPA 430-R-11-005, U.S. Environmental Protection Agency: Washington, D.C.

EPA, 2010a, *2009 Natural Gas STAR Program Accomplishments*. Available at: http://www.epa.gov/gasstar/documents/ngstar_accomplishments_2009.pdf (accessed May 25, 2011).

EPA, 2010b, *Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry, Background Technical Support Document*, U.S. Environmental Protection Agency: Washington, D.C.

EPA, 2007, *Reducing Methane Emissions during Completion Operations*, Natural Gas STAR Producer's Technology Transfer Workshop, Glenwood Springs, Colo., Sept. 11.

EPA, 2006, *Installing Plunger Lift Systems in Gas Wells: Lessons Learned from Natural Gas STAR Partners*, U.S. Environmental Protection Agency: Washington, D.C. Available at: http://epa.gov/gasstar/documents/ll_plungerlift.pdf. (accessed May 25, 2011).

EPA, 2004a, *Exhaust and Crankcase Emission Factors for Nonroad Engine Modeling — Compression-Ignition*, NR-009c, EPA420-P-04-009, revised April. Available at: http://www.epa.gov/OMS/models/nonrdmdl/nonrdmdl2004/420p04009.pdf (accessed April 16, 2010).

EPA, 2004b, *Green Completions*, Natural Gas STAR Producer's Technology Transfer Workshop, Houston, Tex., Sept. 21.

EPA, 1993, *Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Offshore Subcategory of the Oil and Gas Extraction Point Source Category*, EPA 821-R/93-003.

Gaudlip, A.W., L.O. Paugh, and T.D. Hayes, 2008, "Marcellus Shale Water Management Challenges in Pennsylvania," presented at the 2008 SPE Shale Gas Production Conference, Fort Worth, Tex., November 16–18.

Geankoplis, C.J., 1993, *Transport Processes and Unit Operations, 3rd Edition*, Prentice-Hall, Inc.: Englewood Cliffs, New Jersey, p 133–134.

GAO (U.S. Government Accountability Office), 2010, *Federal Oil and Gas Leases: Opportunities Exist to Capture Vented and Flared Natural Gas, Which Would Increase Royalty Payments and Reduce Greenhouse Gases*, GAO-11-34, U.S. Government Accountability Office: Washington, D.C.

GWPC and ALL (Ground Water Protection Council and ALL Consulting), 2009, *Modern Shale Gas Development in the United States: A Primer*, prepared for U.S. Department of Energy Office of Fossil Energy and National Energy Technology Laboratory. Available at: http://fossil.energy.gov/programs/oilgas/publications/naturalgas_general/Shale_Gas_Primer_2009.pdf (accessed December 15, 2010).

GTI (Gas Technology Institute), 2001, *Gas Resource Database: Unconventional Natural Gas and Gas Composition Databases*, Second Edition, GRI-01/0136.

Hanle, L., 2011, personal communication among L. Hanle, U.S. Environmental Protection Agency, D. Sechler, ICF International, and A. Burnham, C. Clark, J. Dunn, and J. Han, Argonne National Laboratory, May 9.

Harrison, M.R., L.M. Campbell, T.M. Shires, and R.M. Cowgill, 1996, *Methane Emissions from the Natural Gas Industry, Volume 2*, EPA/600/R-96/080B, U.S. Environmental Protection Agency: Washington, D.C.

He, D., and M. Wang, 2000, "Contribution of Feedstock and Fuel Transportation to Total Fuel-Cycle Energy Use and Emissions," SAE paper 2000-01-2976.

Howarth, R.W., R. Santoro, and A. Ingraffea, 2011, "Methane and the Greenhouse-Gas Footprint of Natural Gas from Shale Formations," *Climatic Change* 106, 679–690.

IEA (International Energy Agency), 2006, *Focus on Clean Coal*, International Energy Agency: Paris, France.

INTEK (INTEK, Inc.), 2011, *Review of Emerging Resources: U.S. Shale Gas and Shale Oil Plays*, prepared for the Energy Information Administration: Washington, D.C.

IPCC (Intergovernmental Panel on Climate Change), 2007, *Climate Change 2007: The Physical Science Basis: Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change*, Cambridge University Press.

Kern River Gas Transmission Company, 2010, *Construction Fact Sheet*. Available at: http://www.kernrivergas.com/InternetPortal/DesktopModules/ViewDocument.aspx?DocumentID=734 (accessed December 15, 2010).

Kirchgessner, D.A., R.A. Lott, R.M. Cowgill, M.R. Harrison, and T.M. Shires, 1997, "Estimate of Methane Emissions from the U.S. Natural Gas Industry," *Chemosphere* 35, 1365–1390.

Lelieveld, J., S. Lechtenbohmer, S.S. Assonov, C.A.M. Brenninkmeijer, C. Dienst, M. Fischedick, and T. Hanke, 2005, "Greenhouse Gases: Low Methane Leakage from Gas Pipelines," *Nature* 434, 841–842.

Mansure, A.J., 2010, "Review of Past Geothermal Energy Return on Investment Analyses," *GRC Transactions*, Geothermal Resources Council, Davis, CA.

Mantell, M.E., 2010a, personal communication between M.E. Mantell, Chesapeake Energy, and C.B. Harto, Argonne National Laboratory, Washington, D.C., December 20.

Mantell, M.E., 2010b, "Deep Shale Natural Gas and Water Use, Part Two: Abundant, Affordable, and Still Water Efficient," *Water/Energy Sustainability Symposium at the 2010 GWPC Annual Forum*, Pittsburgh, Penn.

Nakles, D.V., I. Ortiz, and J.R. Frank, 1992, "An Analysis of Management Strategies for Produced Waters from Natural Gas Production," *Produced Water Technological/Environmental Issues and Solutions*, Environmental Science Research 46, 73–88.

Overbey, W.K., R.S. Carden, C.D. Locke, S.P. Salamy, T.K. Reeves, and H.R. Johnson, 1992, Site Selection, Drilling, and Completion of Two Horizontal Wells in the Devonian Shales of West Virginia, prepared for U.S. Department of Energy, DOE/MC/25115--3116.

Percival, P., 2010, "Update on 'Lost and Unaccounted for' Natural Gas in Texas," *Basin Oil & Gas*, July/August. Available at: http://fwbog.com/index.php?page=article&article=248 (accessed June 1, 2011).

Radback Energy, 2009, "Appendix 5.1E Construction Data," *Contra Costa Generating Station — Application for Certification*, prepared for the California Energy Commission, Docket 09-AFC-4. Available at: http://www.energy.ca.gov/sitingcases/oakley/documents/applicant/afc/Volume%202/CCGS_ Appendix%205.1E_Construction%20Data.pdf (accessed December 21, 2011).

Range Resources, 2010a, Well Record and Completion Report: Baker Carol 5H. Available at: http://www.rangeresources.com/getdoc/0651ae63-6b22-49f6-91b0-ba8931870094/Baker-Unit-5H.aspx (accessed May 25, 2011).

Range Resources, 2010b, Well Record and Completion Report: Baker Carol 4H. Available at: http://www.rangeresources.com/getdoc/87529e5c-c15f-4846-b450-b44ae68b378f/Baker-Unit-4H.aspx (accessed May 25, 2011).

Range Resources, 2010c, Well Record and Completion Report: Baker Carol 6H. Available at: http://www.rangeresources.com/getdoc/d8bdbf42-0028-45aa-bd4c-324a3a1b78f5/Baker-Unit-6H.aspx (accessed May 25, 2011).

Samuels, J., 2010, *Emission Reduction Strategies in the Greater Natural Buttes*, Natural Gas STAR Producer's Technology Transfer Workshop, Vernal, Utah, March 23.

Shindell, D.T., G. Faluvegi, D.M. Koch, G.A. Schmidt, N. Unger, and S.E. Bauer, 2009, "Improved Attribution of Climate Forcing to Emissions," *Science* 326, 716–718.

Shires, T.M., C.J. Loughran, S. Jones, and E. Hopkins, 2009, *Compendium of Greenhouse Gas Emission Methodologies for the Oil and Natural Gas Industry*, American Petroleum Institute: Washington, D.C.

Stinson, K., 2008, "Water Resource Management in the Barnett Shale," Meeting of the Texas Association of Clean Water Agencies, Fort Worth, Tex., Nov. 21. Available at: http://tacwa.org/images/Water_Resource_Management_in_the_Barnett_Shale.pdf (accessed August 4, 2011).

Swindell, G., 2001, "Changes in the Performance of Texas Gas Wells," SPE Permian Basin Oil and Gas Recovery Conference, May 15–17, Midland, Tex.

Tester, J., et al., 2006, *The Future of Geothermal Energy: Impact of Enhanced Geothermal Systems (EGS) on the United States in the 21st Century*, Massachusetts Institute of Technology. Available at: http://geothermal.inel.gov/publications/future_of_geothermal_energy.pdf (accessed August 2010).

Veil, J.A., 2010, *Water Management Technologies Used by Marcellus Shale Gas Producers*, ANL/EVS/R-10/3, Argonne National Laboratory; Argonne, Ill.; July.

Wang, M., Y. Wu, and A. Elgowainy, 2007, *Operation Manual: GREET 1.7*, ANL/ESD-05-3, Center for Transportation Research, Argonne National Laboratory, Argonne, Ill.

Wang, M.Q., 1999, GREET 1.5 — Transportation Fuel-Cycle Model: Volume 1, Methodology, Use, and Results, ANL/ESD-39, Vol. 1, Center for Transportation Research, Argonne National Laboratory, Argonne, Ill.

Wang, M., and H. Huang, 1999, *A Full Fuel-Cycle Analysis of Energy and Emissions Impacts of Transportation Fuels Produced from Natural Gas*, ANL/ESD-40, Center for Transportation Research, Argonne National Laboratory, Argonne, Ill., Dec.

Energy Systems Division
Argonne National Laboratory
9700 South Cass Avenue, Bldg. 362
Argonne, IL 60439-4815

www.anl.gov

Argonne National Laboratory is a U.S. Department of Energy
laboratory managed by UChicago Argonne, LLC