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Harmonization of initial estimates of shale gas life cycle greenhouse gas emissions for electric power generation

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Recent technological advances in the recovery of unconventional natural gas, particularly shale gas, have served to dramatically increase domestic production and reserve estimates for the United States and internationally. This trend has led to lowered prices and increased scrutiny on production practices. Questions have been raised as to how greenhouse gas (GHG) emissions from the life cycle of shale gas production and use compares with that of conventionally produced natural gas or other fuel sources such as coal. Recent literature has come to different conclusions on this point, largely due to differing assumptions, comparison baselines, and system boundaries. Through a meta-analytical procedure we call harmonization, we develop robust, analytically consistent, and updated comparisons of estimates of life cycle GHG emissions for electricity produced from shale gas, conventionally produced natural gas, and coal. On a per-unit electrical output basis, harmonization reveals that median estimates of GHG emissions from shale gas-generated electricity are similar to those for conventional natural gas, with both approximately half that of the central tendency of coal. Sensitivity analysis on the harmonized estimates indicates that assumptions regarding liquids unloading and estimated ultimate recovery (EUR) of wells have the greatest influence on life cycle GHG emissions, whereby shale gas life cycle GHG emissions could approach the range of best-performing coal-fired generation under certain scenarios. Despite clarification of published estimates through harmonization, these initial assessments should be confirmed through methane emissions measurements at components and in the atmosphere and through better characterization of EUR and practices.

life cycle assessment | methane leakage | meta-analysis

The acceleration of natural gas production from shale deposits has already had a major impact on the energy outlook in the United States and globally. The rapidity of this shift, along with the associated acceleration of natural gas liquids and shale and tight oil production, has challenged many areas of regulation and science. These changes have invigorated several areas of inquiry, ranging from water use and impacts on water quality (1, 2), concerns about air emissions (3, 4), and potential greenhouse gas (GHG) benefits compared with other fossil fuels (5). Natural gas, consisting mostly of methane, has the lowest amount of carbon per unit of energy among fossil fuels and has thus been promoted as a transition fuel to a lower carbon economy, with some evidence in support (6, 7), whereas other reports suggest little benefit or even negative effects on the climate over longer time scales (8, 9).

The impact of shale gas on climate change, as with all fossil fuels, is a complex but direct function of GHGs emitted in the full life cycle, from exploration through development and production to end use (see Fig. S1 for a diagram of natural gas life cycle stages and Table S1 for a list of GHG-emitting processes). Although on this life cycle basis, end-use combustion of gas has been consistently found to contribute the most to total GHG emissions (5, 10-16), three natural gas production processes have been highlighted as potentially important: well completion and recompletion, including hydraulic fracturing, and well liquids unloading. Briefly, well completion is the process of preparing a newly drilled well for production, which for shale gas wells includes hydraulic fracturing (the process of forcing specially formulated solutions into a well at high pressure creating fractures in rocks through which trapped gas can flow to the well) and subsequent flowback of the solution to the surface along with entrained natural gas. Recompletions repeat the hydraulic fracturing process later in the well lifetime to increase production. Liquids unloading is the periodic removal from a well of liquids and other debris that impede gas flow. Note that of all processes within the life cycle of production and use of natural gas, only the hydraulic fracturing process and subsequent flowback are unique to shale gas compared with conventional gas.

Hundreds of life cycle assessments (LCA) passing screens for quality and relevance to the generation of electricity have been identified in a systematic review of this growing area of inquiry, including ∼40 for conventionally produced natural gas (i.e., natural gas produced without hydraulic stimulation; henceforth, conventional gas) (17). Assessments relevant to life cycle GHG emissions of shale gas are more recent (10–16, 18), mostly conducted in the context of the use of gas for electric power generation. Results of these studies, as reported in their abstracts and reflected in the media (19, 20), reveal very different conclusions about the climate implications from use of these fuels: from shale and conventional gas having higher life cycle GHG emissions than coal (18), to shale gas having greater emissions than conventional but less than coal (10–12, 14; or just a comparison with coal in ref. 16), to conventional gas having greater emissions than shale gas and both less than coal (13, 15).

Significance

Previously published life cycle assessments (LCAs) of greenhouse gas emissions from the production and use of shale gas have come to widely varying conclusions about both the magnitude of emissions and its comparison with conventionally produced natural gas and coal for electricity generation. We harmonize estimates from this literature to establish more consistently derived and robust summary of the current state of knowledge. Whereas median estimates for both gas types appear less than half that of coal, alternative assumptions may lead to emissions approaching best-performing coal units, with implications for climate change mitigation strategies.

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Despite an internationally recognized standard of practice (21), direct comparison of LCAs and pooling of their results for common understanding is thwarted by analysts' varied choices of data sources, system boundaries, modeling approaches, and inclusion or exclusion of specific activities. These varied but generally legitimate choices lead to divergent outcomes, leaving decision makers without a robust foundation on which to base decisions. Recently, meta-analytical techniques have been applied to the results of LCAs, where the goal is to develop broader and more robust insight from the available body of literature on a similar topic (e.g., 22–24). Our approach, called harmonization, differs from statistically oriented analyses (e.g., Monte Carlo) to address the challenges of inconsistency among LCAs by ensuring comparability before meta-analysis.

We present results of harmonization of eight peer-reviewed LCAs reporting 10 original estimates of life cycle GHG emissions from the use of shale gas for electricity generation (10–16, 18).[i,ii] We compare results from these LCAs to prior harmonization of 200 estimates of life cycle GHG emissions for conventional gas and coal power generation (23, 26). Our aim is to develop consistent comparisons of the results of each prior shale gas LCA, as well as for LCAs for conventional gas and coal and to pool results to provide insight into the question of which fuel source for power generation has lower life cycle GHG emissions: shale gas, conventional gas, or coal. This process of harmonization normalizes to a common metric of grams carbon dioxide-equivalent per kilowatt-hour of electrical output (g CO_2e/kWh) while ensuring consistent system boundaries and sets of major activities throughout the production and use of shale gas. Harmonization also provides an opportunity for updating of previous estimates based on more recent understanding. For instance, as differentiated from prior meta-analysis of shale LCAs (25), we ensure that emissions from liquids unloading is included in all shale gas LCAs based on the latest evidence from nearly 43,000 wells (27) and update results to reflect the latest (2013) Intergovernmental Panel on Climate Change (IPCC) global warming potential (GWP) for methane (28). In addition, we perform a sensitivity analysis of the three aforementioned activities in shale gas production—completions, recompletions,[iii] and liquids unloading—to demonstrate the potential impact on life cycle GHG emissions of their uncertainty and variability, including a comprehensive assessment of the critical input parameter of well lifetime production [or estimated ultimate recovery (EUR)] based on the development of a national probability distribution function.

Results and Discussion

Studies Contrasted. Proper interpretation of any LCA, or meta-analysis thereof, starts with a careful understanding of how each study is framed and its key assumptions. Some of these attributes are amenable to harmonization, whereas others are differences that are either irreducible or deemed beyond the scope of harmonization. Table 1 summarizes key assumptions and scopes of the independently constructed shale gas LCAs that highlight their major points of difference. Enumeration of additional differences is provided in Dataset S1. A review of Table 1 illustrates the challenges for decision makers in consolidating the published results into a robust foundation for decision making about such a large and diverse industry as unconventional natural gas production and use.

Three attributes of these studies are critical to understand for proper interpretation of their results but are not amenable to harmonization. First is the choice of gas type studied. The eight LCAs evaluate different unconventional gas resources and are sometimes representative of specific, and differing, years. Hultman et al. (12) consider all unconventional gas types [shale, tight, coalbed methane (CBM)] together for the year 2007 and Howarth et al. (18) use data reflective of shale and tight gas. The rest, although nominally focused on shale gas, consider different plays or sets of plays [which have differing characteristics such as lifetime production (EUR) and gas composition], use different baseline years, and often use emissions factors representative of other unconventional sources in place of shale-specific factors. Given the different foci of each study, it is understandable why different assumptions about practices and emissions would be made and why LCA results could differ. It is also clear that assessment of a broad set of plays, years, and gas types is important to characterize the large and diverse natural gas industry in the United States. However, these differences confound simple comparisons of published results. For rhetorical simplicity, hereafter we collectively refer to the mixture of different unconventional gas types analyzed in the eight subject LCAs as shale gas because all studies either focused on or included this gas type.

Second, there are two main modeling philosophies used by these studies that, as yet, have been undifferentiated in the literature. Longitudinal studies develop a model of activities for a typical well (or set of wells) across its life cycle, along with emission factors for each activity, scaled to their contribution to the final product (here, a kWh of generated electricity), and then sum emissions across all activities (in space and time) to achieve an estimate of life cycle GHG emissions per unit of final product. This approach is the classic, so-called (engineering) "process-based" LCA (21). Alternatively, cross-sectional studies use annual inventory of emissions representative of all wells in a given geographic area at all stages of their lives (being drilled, completed, early or late-stage production, recompleted, or decommissioned) in that given year and then divide by annual gas production from that year to estimate life cycle GHG emissions in the appropriate functional unit. There are tradeoffs to each approach. The longitudinal approach provides fine resolution to modeled processes and facilitates sensitivity and uncertainty analyses, but it is generally unproven how well the data collected to represent each life cycle process simulate the actual characteristics of the intended population (central tendency and variability). The cross-sectional approach uses aggregate data meant to be representative of actual performance during a given time period, but is dependent on the accuracy of the estimation methods of the inventory (a limiting factor for natural gas production-related GHG emissions currently). In addition, results will change year to year as the level of activity changes and may not reflect the life cycle of activities for a well (e.g., completions nationally in a given year may contribute a larger fraction of total emissions than what is reflective of their contribution to the production of 1 kWh). The eight shale gas LCAs represent a mixture of these two approaches.

Third, as an LCA is designed to inform decisions among alternatives providing the same function, all studies but two composed comparison cases nominally of conventional gas yet differing in significant ways (Table 1).[iv] Note that some studies examine specific types of conventional sources (11, 14), whereas others use defined mixtures of conventional gas types (11–13), unspecified mixtures (15, 18), or even mixtures of all domestic US sources, including unconventional (10, 33). Harmonization cannot adjust the focus of each study but can rigorously highlight distinctions to inform the review of the set of available studies.

There are also key study attributes more amenable to ex poste facto harmonization. In this category, one important difference

[i]Weber and Clavin (25) is a Monte Carlo-based synthesis of results from six unconventional gas LCAs and thus included for perspective but not harmonization.

[ii]For rhetorical simplicity, these eight LCAs will sometimes be referred to by the first author's last name.

[iii]Restimulation is a synonymous term to recompletion; workover can refer to well maintenance without hydraulic fracturing (29, 30), or mean recompletion (31).

[iv]Heath et al. (15) didn't create their own comparison case, but rather compared Barnett shale results to harmonization of 42 references (26) that collectively focus on a diverse set of conventional or domestic gas types. Laurenzi and Jersey (16) compared their results to coal only; we use the results of O'Donoughue et al. (26) for comparison with Laurenzi and Jersey where necessary.

Table 1. Key assumptions in shale gas LCAs for base case scenario

Study (ascending by publication date)	Unconventional gas type	Modeling philosophy*	Comparison case(s)	Functional unit	100-y CH_4 GWP	Power plant efficiency (HHV)	Coproduct allocation	EUR (bcf)	CH_4 emission rate† (% CH_4 loss/NG produced)	Key data source(s)
Howarth et al. (18)	Production: shale (Haynesville, Barnett) and tight (Piceance, Uinta); "indirect emissions"‡: Marcellus	Mixture	Generic conventional	g C/MJ fuel energy content	33	NA	None	1.2–7.4	2.8–6.2% (high-low cases)	EPA (31), GAO (32)
Jiang et al. (10)	Marcellus shale	Longitudinal (shale part)	2008 Average US domestic gas (conventional (onshore, offshore), associated, unconventional, CBM) based on the cross-sectional Venkatesh et al. (33)	g CO_2e/kWh generated	25	50%	None	2.7	2.2%+ preproduction	Primary data collection, Venkatesh et al. (33)
Skone et al. (11)	2009 Barnett shale	Longitudinal	2009 Onshore, offshore, associated gas and production-weighted mixture	g CO_2e/kWh delivered	25	50%	NMVOC (12% upstream of AGR)	3.0	3.9%	Primary data collection, EPA (31)
Hultman et al. (12)	2007 National average unconventional (shale, tight, and CBM)	Cross-sectional	2007 National average consumed, conventional natural gas (onshore, offshore, assoc. gas, LNG including imports)	g CO_2e/kWh generated	25	46%	None	N.R.	2.8%	EPA (31), EPA (34)
Burnham et al. (13)	EUR: well-weighted average of Marcellus, Barnett, Haynesville, Fayetteville shales; emission factors for generic unconventional	Cross-sectional	2009 National average conventional (onshore and offshore plus associated)	g CO_2e/kWh generated	25	43%	None	3.5	2.0%	EPA (31)
Stephenson et al. (14)	US shale gas	Longitudinal (simplified model)	US onshore conventional gas	g CO_2e/kWh generated	25	43%	Condensate, ethane, LPG (12%)	2.0	0.66%	Primary data collection, EPA (31)
Heath et al. (15)	2009 Barnett shale	Mixture§	Harmonized estimates from 42 conventional gas LCAs (26)	g CO_2e/kWh generated	25	51%	Condensate, oil (1%)	1.4	1.3%	TCEQ inventories (15), EPA (31)
Laurenzi and Jersey (16)	2010–2011 Marcellus shale	Longitudinal	US coal fleet¶	g CO_2e/kWh generated	25	50%	NGL (19.7% before processing)	1.8	1.4%	Primary data from XTO operations; EPA (31)

AGR, acid gas removal; GAO, General Accountability Office; LNG, liquefied natural gas; NA, not applicable; NG, natural gas; NGL, natural gas liquids; NMVOC, nonmethane volatile organic compounds; NR, not reported; TCEQ, Texas Commission on Environmental Quality.

*A cross-sectional modeling philosophy considers all emissions from an economic sector in a given year. The longitudinal philosophy builds a linear model of the life cycle and then estimates emissions at each step in the life cycle, sometimes leveraging cross-sectional data. See main text for further description.

†Description of published methane emission rates and the harmonization process for this parameter is detailed in *SI Text*.

‡Indirect emissions refers to all GHG emissions except methane leakage, e.g., CO_2 emissions from engines, land clearing, and GHG emissions embodied in materials like concrete, steel, and chemicals (35).

§Production, processing, and waste disposal emissions are based on cross-sectional analysis of 2009 TCEQ volatile organic compound emission inventories (15); the remainder of stages analyzed as process LCA (longitudinal).

¶This study uses O'Donoughue et al. (26) to provide a conventional gas comparison case for Laurenzi and Jersey.

among studies is their selected unit for normalization of results (known as the "functional unit" in LCAs). Howarth et al. (18) report results per megajoule of fuel energy content, whereas Skone et al. (11) report per kilowatt hour-delivered electricity, and all others use per kilowatt hour generated. These distinctions can be harmonized to compare results using a consistent functional unit; we have selected a kilowatt hour generated.

Next, results have been presented using 20- and 100-y GWPs for methane, using values from the IPCC's fourth assessment report (AR4) (36) or reflecting the author's choice of an alternative estimate of GWP (18). The range of GWPs used were 25–33 for the 100-y horizon and 72–105 for 20-y horizons, the low end being AR4-reported values and the high end based on research that considers aerosol interaction (37). Alvarez et al. (5) have proposed an alternative metric that considers the continuum of impact timescales, but for the purposes of this harmonization analysis, all previous estimates are adjusted to 100-y GWPs following standards adopted for LCAs and carbon footprint protocols (21, 38). We have updated all previous LCAs to use the latest IPCC assessment report, AR5, which increased the GWP for methane to 30 for sources of fossil origin from 25 in AR4 (28).

Finally, the assumed power plant thermal efficiency differs for each study, ranging from 43% to 50% on a higher heating value basis (Table 1). GHGs emitted from combustion at the power plant contribute by far the largest portion of life cycle GHG emissions from natural gas electricity generation (and coal) (12, 15, 23). Despite the importance of this parameter and difference of opinion over which value is most informative to today's policy debates (12, 25), harmonization is applied to adjust each estimate to the same thermal efficiency—51%, reflective of a modern combined cycle plant (39)—to improve comparability and highlight the relative importance of other parameters about which the state of knowledge is less developed. At this thermal efficiency, power plant combustion contributes ~360 g CO_2/kWh.

Harmonization Results. Table 2 reports published results of the reviewed LCAs categorized by type of gas evaluated. For shale gas, published results range from 437 to 758 g CO_2e/kWh (median, 488 g CO_2e/kWh), with similar results when including an estimate for unconventional gas (including shale, tight, and coal bed methane) (12). Table 2 also reports the results of harmonization for the base cases [except Howarth et al. (18), who only report a high and low result] of the eight shale gas LCAs, noting the specific factors adjusted for each estimate (with results of each harmonization step reported in Dataset S2). In most cases, harmonization resulted in a decrease in estimate of life cycle GHG emissions, but the magnitude of change varied from −2% to −14%. Four estimates increased slightly (1–5%) because, for these cases, the applicable harmonization steps resulted in unidirectionally increased estimates of life cycle GHG emissions, even when counterbalanced by decreases from efficiency adjustments. The most influential harmonization steps varied by study, but generally included thermal efficiency, recompletion-related adjustments (inclusion or frequency adjustment), GWP, the inclusion of liquids unloading, and, for the one study on which it was applied, transmission and distribution loss (T&D loss) harmonization (Dataset S2).

The primary motivation for completing these LCAs has been to answer the question of whether shale gas (or unconventional gas more generally) has higher GHG emissions than conventional gas or other fossil fuels like coal. Harmonization was applied to the comparison conventional gas life cycle GHG emission estimates where available in the eight shale gas LCAs in analogous ways as it was for shale gas estimates; this resulted in a similar proportional decrease in estimates (with two cases of slight increase; Dataset S2). Whereas before harmonization, the median estimate of intrastudy difference between unconventional and conventional life cycle GHG emissions was +4%, after harmonization it was reduced to +3% (Table 2). The median estimates of shale (plus unconventional) and conventional (plus domestic) gas after harmonization of the eight evaluated studies are nearly identical: 465 g CO_2e/kWh for shale and 461 g CO_2e/kWh for conventional. In previous comparisons of life cycle GHG emissions between unconventional and conventional gas, liquids unloading for conventional wells provided some balance to the higher emissions from unconventional well completion. Current understanding is shifting this balance, given that liquids unloading is now known to be applicable to unconventional wells (27), and emissions factors for these activities have changed over time (*Methods*).

O'Donoughue et al. (26), considering all 42 references with life cycle GHG emission estimates for conventional gas-fired combined cycle (NGCC) facilities passing screens for relevance and quality (including all shale gas LCAs considered here that published an estimate for conventional gas), found that the published range of the middle 50% of 51 estimates[v] is ~410–490 g CO_2e/kWh (full range, ~310–680 g CO_2e/kWh), with a median of 450 g CO_2e/kWh. After harmonization with consistent steps as implemented here for the eight shale gas LCAs, variability decreased (e.g., −13% in interquartile range), whereas the magnitude of estimates, in aggregate, remained constant, yielding a harmonized median of 450 g CO_2e/kWh. Thus, the results from the larger set of conventional gas LCAs considered in O'Donoughue et al. (26) suggests that the harmonized median estimate of life cycle GHG emissions from shale gas used to generation electricity in a modern combined cycle facility are slightly higher (3%) than those from conventional gas used for the same purpose. Considering the expected uncertainty ranges given the breadth of assumptions used in LCAs and that the results in O'Donoughue et al. could not be updated to use the AR5 methane GWP (*Methods*), our conclusion is that based on current evidence, life cycle GHG emissions from shale and conventional gas are not significantly different (Fig. 1).

For coal-fired electricity generation, Whitaker et al. (23) found that the middle 50% of 164 harmonized estimates of life cycle GHG emissions from 53 references passing screens for quality and relevance was 940–1,050 g CO_2e/kWh (full range, 820–1,370 g CO_2e/kWh), with a median of 980 g CO_2e/kWh (Fig. 1). From the pool of published estimates, there is only one overlapping for coal and natural gas combined cycle electricity generation (for conventional gas). Note that harmonization for coal used thermal efficiencies relevant to modern coal-fired generation facilities (*Methods*).

Sensitivity Analysis. We undertook sensitivity analysis focused on three important activities in the production of shale gas—well completion, well recompletion, and liquids unloading—each chosen because previous research had found them significant to life cycle GHG emissions and uncertainty (11, 13, 23). After subtracting the authors' estimate of GHG emissions from a given activity from the harmonized life cycle GHG emission value, a common high and low bound estimate for each activity was added. The high-low bounds for each activity were calculated starting with a central estimate developed using the latest available information on each activity, and then varying the central estimate using published ranges of key input parameters. For completions, the key parameters were proportion of potential emissions flared or otherwise reduced (0–76%) (31) and EUR [0.4–7 billion cubic feet (bcf) (41); displayed in Fig. S2]; for recompletions, well lifetime was also considered (3–30 y) (14, 41). For liquids unloading, a slightly different approach was necessary. Given emissions estimates reported in ref. 27 that take into account reductions from potential emissions through plunger and artificial lifts reported at the operator level, we were able to construct a national distribution of emissions per well that we then parametrically analyzed for sensitivity to well-level assumptions

[v]Note that each reference could report more than one estimate.

Table 2. Published and harmonized estimates of life cycle GHG emissions (g CO_2e/kWh) from electricity generated using different types or mixes of natural gas

Reference (ascending by publication date)*	Shale		Unconventional		US Domestic[†]		Conventional		Percent difference unconventional to conventional[‡]		Harmonization factors[§]
	Published	Harmonized	Published	Harmonized	Published	Harmonized	Published	Harmonized	Published	Harmonized	
Howarth et al. high (18)[¶]	758	746					671	647	13%	15%	Eff, PP, GWP, R (shale)
Howarth et al. low (18)[¶]	554	567					471	473	18%	20%	Eff, PP, GWP, U, R (shale)
Jiang et al. (10)/Venkatesh et al. (33)[‖]	488	497			473	487			3%	2%	Eff, PP, GWP, Pre-P (33), R (10)
Skone et al. (11) (Barnett)**	488	438					469	439	4%	0%	Eff, GWP, T&D, RF (shale), U (shale)
Skone et al. (11) (Marcellus)**	486	438					469	439	4%	0%	Eff, GWP, T&D, RF (shale), U (shale)
Hultman et al. (12)			529	460			476	438	11%	5%	Eff, PP, GWP, Pre-P, RF (unconv.), U (unconv.)
Burnham et al. (13)	602	517					639	557	−6%	−7%	Eff, PP, GWP, RF (shale), U (shale)
Stephenson et al. (14)	499	434					489	420	2%	3%	Eff, PP, GWP, U (conv.), R (shale)
Heath et al. (15)/O'Donoughue et al. (26)[††]	437	459					450	450	−3%	2%	GWP (shale), U (shale)
Laurenzi and Jersey (16)/O'Donoughue et al. (267)[§§]	466	470					450	450	4%	4%	Eff, GWP, PP, R (all shale)
Median	488	470	529	460	473	487	476	450			
Median (grouped)[¶¶]	493	465					475	461	4%	3%	

*Published NGCC results were selected when available; Stephenson et al. (14) evaluated 2009 US average natural gas power plant. Published results using 100-y GWPs were selected, except Howarth et al. (18), who evaluated a 20-y GWP. Published results from Skone et al. (11) are per kilowatt hour delivered; all others are per kilowatt hour generated. Central results are analyzed here; results of sensitivity and uncertainty analyses are not evaluated.

[†]"US domestic" is the production-weighted sum of all types of natural gas (conventional, associated, unconventional, and coal bed methane) (33).

[‡]Percent difference in shale/unconventional estimate from conventional/domestic baseline. Median is most meaningful for grouped results.

[§]Factors are applied to all estimates in row unless specifically noted. Eff, power conversion efficiency harmonized to 51%; PP, power plant upstream and downstream-related emissions added; GWP, global warming potential harmonized to 100-y IPCC values (28); T&D, electricity transmission and distribution losses removed; Pre-P, gas well preproduction-related emissions added; U, a central estimate for methane emissions from liquids unloading added, for shale wells this estimate is adjusted to base case EUR of each study (Table S2); R, estimate of unconventional well recompletion emissions added based on study's reported completion emissions and final NSPS frequency (40); RF, reported unconventional well recompletion emissions adjusted to final NSPS frequency (40); unconv., unconventional.

[¶]Results published in Howarth et al. (18) have been adjusted to commensurate units assuming power conversion efficiency for an NGCC of 51% (26).

[‖]Venkatesh et al. (33) (domestic gas) provides the comparison case for Jiang et al. (10) (shale gas), as well as the estimate of emissions besides preproduction. Venkatesh et al. (33) includes an estimate for liquids unloading, which is then assumed in Jiang et al.'s (10) estimates because Jiang et al. only model preproduction-related emissions.

**Conventional results for Skone represent those for their production-weighted conventional mix (onshore, offshore, and associated gas).

[††]Heath et al. uses O'Donoughue et al. (26) as the conventional gas comparison case.

[§§]O'Donoughue et al. (26) is used here as the conventional gas comparison case for Laurenzi and Jersey.

[¶¶]Groups are shale plus unconventional and conventional plus domestic.

of EUR and lifetime. The high and low bound estimates of each key parameter were the same for each activity, when applicable (see following text and *SI Text* for more detail). Note that this approach still does not harmonize for life cycle methane leakage, only the contribution from each of the three activities explored in this sensitivity analysis.

Shale gas life cycle GHG emissions are found to be most sensitive to assumptions about liquids unloading (Fig. 2), for which evidence of its applicability to unconventional wells has only recently been published (27). The wide range in estimates of life cycle GHG emissions from liquids unloading is a consequence of the range in emissions per unloading event for nearly 43,000 wells self-reported by operators to their industry associations [American Petroleum Institute and the American Natural Gas Association (API/ANGA)] (27) (Table S3). Although the vast majority of self-reported liquids unloading events contribute minimal GHG emissions in the context of natural gas for electricity generation, the upper end of the distribution could contribute ~200 g CO_2e/kWh. At such levels, liquids unloading alone could represent 30% of the median life cycle GHG emissions estimate for shale gas.

Shale wells with high emissions from liquids unloading (e.g., no emission controls, frequent unloading, and/or poor practices) combined with low EURs lead to estimates of life cycle GHG emissions that could approach those of best-performing coal-fired electricity generation units (Fig. 1). This circumstance could also be true for conventional wells, noting the similarly high and skewed distribution of emissions from liquids unloading reported in ref. 27 (Table S3). It should be noted that the US Environmental Protection Agency's (EPA's) most recent New Source Performance Standard and National Emissions Standards for Hazardous Air Pollutants (NSPS/NESHAPs) rules do not address liquids unloading (40).

The insensitivity of life cycle GHG emissions to assumptions about well recompletions found here differs from previous analyses owing to the 10× reduction (10% to 1%) in annual recompletion frequency recently adopted by the EPA (40). Variability in GHG emissions from shale well completion is important, as others have found (11), but not as much as liquids unloading. In addition, opportunities for reducing emissions from completions exist, generally appear effective (42), and will be required nationally for most new wells in 2015 under EPA's NSPS/NESHAPs rules for the industry (40).

Note that the sensitivity range for each activity estimated here may be overestimated if correlations exist between the tested parameters. (Without published correlation coefficients available, we assume independence.) However, because sensitivity was assessed for each activity individually, the combined effect of these three activities could exceed the sum of values estimated for each activity alone. The combined effect is a complex function of interrelated dependencies on key parameters such as EUR, well productivity depletion curve, and gas-to-water ratio, and the effect of these parameters on emissions from the activities examined here (e.g., frequency of well unloading), which is an area of potential future research, as

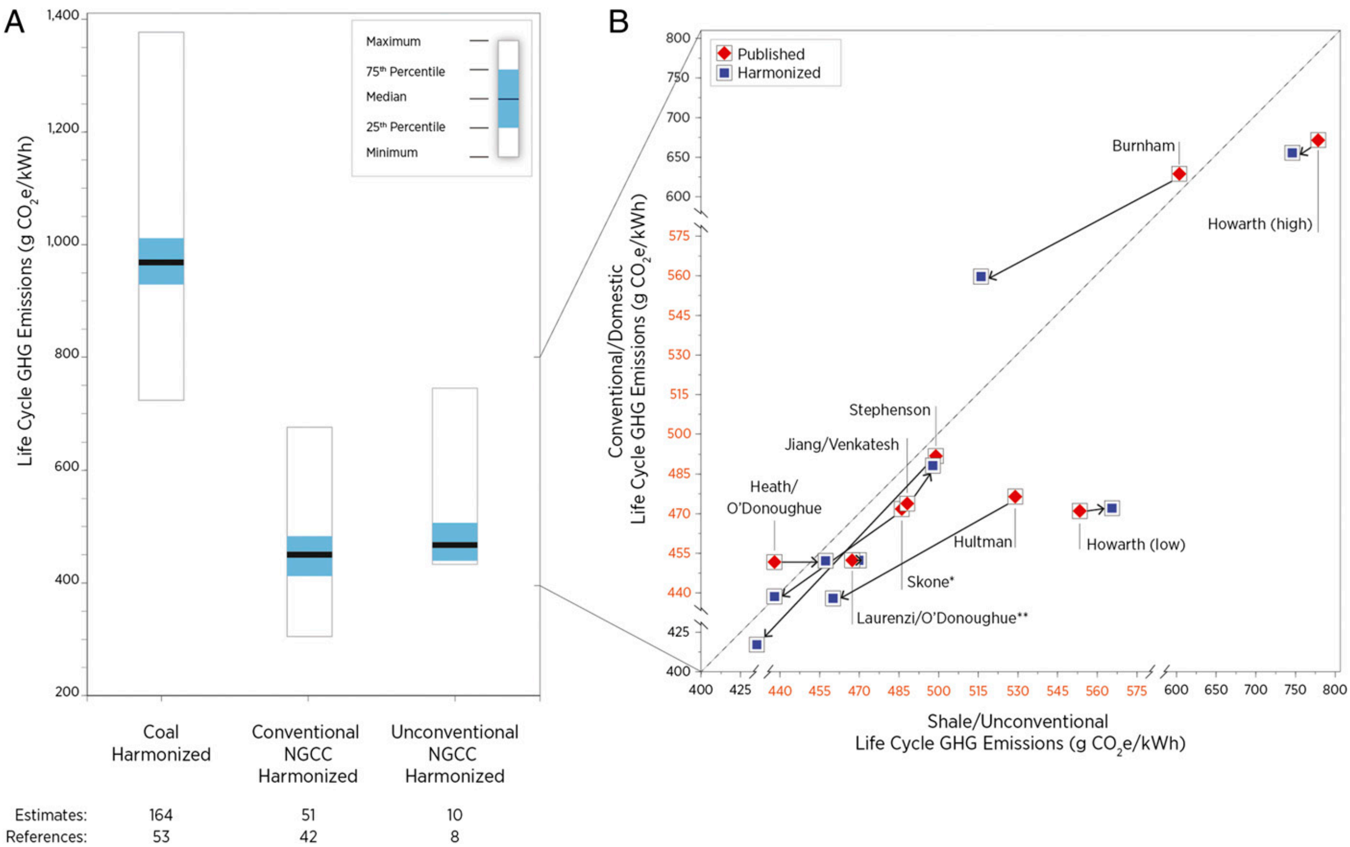

Fig. 1. Distribution of harmonized estimates of life cycle GHG emissions for unconventional gas used for electricity generation in a combined cycle turbine (NGCC) compared with electricity generated from conventional gas (26) and coal (23) (*A*) with detailed results of harmonization of estimates for conventional and unconventional gas (*B*). Those estimates below the 1:1 line in *B* indicate higher life cycle GHG emissions for shale (or unconventional) gas used in an NGCC than for conventional (or domestic) gas and vice versa. Harmonization generally resulted in a reduction in life cycle GHG emission estimate for both shale and conventional gas and movement closer to the 1:1 line. *For clarity, only the Barnett estimate from Skone et al. (11) is shown, but Marcellus is overlapping; **The symbols for the published and harmonized estimates for Laurenzi and Jersey (16)/O'Donoughue et al. (26) overlap.

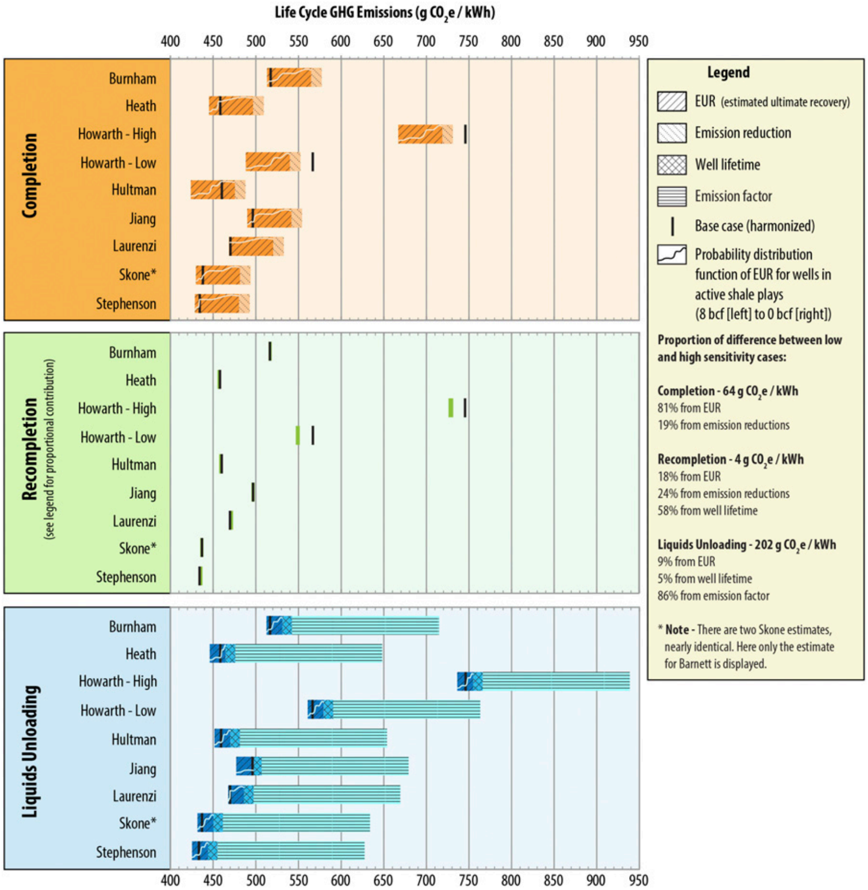

Fig. 2. Sensitivity of harmonized estimates of life cycle GHG emissions for shale gas combusted in a NGCC generator to three activities—well completion, recompletion, and liquids unloading—based on alternative assumptions for EUR, emission reductions, well lifetime, and emission factor (just for liquids unloading). Overlaid within the fraction of sensitivity to EUR is a probability distribution function (PDF) of well EUR for seven active plays, demonstrating the substantial fraction of wells with lower EURs (right side of PDF) than tested in the base case of each study. Variability in well EUR accounts for the largest fraction of total sensitivity for completions. For liquids unloading activities, variability in emission factor is the largest contributor to total sensitivity based on analysis of operator self-reported emissions in ref. 27.

well as application of such rigorous sensitivity analysis to conventional wells GHG emissions.

The contribution of the varied parameters to each of the three tested activities is also reported in Fig. 2. EUR is the most influential parameter for completions and second most for liquids unloading. In previous work, EUR has been shown to be an influential parameter on life cycle GHG emissions because it is the denominator over which GHG emissions from one-time (e.g., completion) and episodic (e.g., recompletion and unloading) activities are normalized to the functional unit. The bounds of EUR we tested are based on a probability distribution of EUR for wells in active shale gas plays in the United States. We developed the probability distribution based on our analysis of Energy Information Administration (EIA) data utilized in the National Energy Modeling System (41), which is reported in *SI Text* and Table S4.[vi]

The EUR used in the base case result of the shale gas LCAs evaluated here ranged from 1.4 to 3.5 bcf with lower bounds all above 1 bcf (except for the lower bound in refs. 10, 15, 16 at 0.4–0.5; see Table S2 for details). The lower bound estimate of EUR used in our sensitivity analysis is 0.4 bcf, which represents the 10th percentile of EUR of wells in active shale plays; the 50th percentile is 2.2 bcf (Table S4). Thus, except for Jiang et al. (10), Heath et al. (15), and Laurenzi and Jersey (16), the EUR bounds tested in previous LCAs do not reflect the GHG emissions of a reasonably probable low producing well. (More than 25% of shale wells are estimated to have EUR less than 1 bcf) (41). The difference in EURs tested here and by the previous studies significantly contributes to the characteristically long right tail of sensitivity results compared with the base case estimates (Fig. 2). [Only Howarth et al.'s (18) completion sensitivity results in a significant left tail, owing to those authors' unusually high completion emission estimate compared with the other authors.] Lower EURs increase the estimate of life cycle GHG emissions, and thus, greater knowledge of well EURs is critical to improving the accuracy of life cycle GHG emissions.

Additional Factors. In addition to the factors described above, this section focuses on two additional and critical factors not harmonized: estimate of methane leakage and coproduct allocation. These factors were not harmonized because the varied assumptions can legitimately reflect the diversity of cases chosen for study, true variability in parameter value or practice, or the current state of uncertainty in our knowledge of each topic.

Methane leakage is a summary statistic of the amount of methane emitted to the atmosphere throughout the fuel cycle (both intentional and unintentional), typically reported as a percent of some total. Here, as with the broader study results, there is inconsistency in the reported metric (Dataset S3), requiring unit conversions to make consistent and direct comparisons.[vii] After conversion to mass of methane emitted per mass of

[vi]The findings reported here are robust to use of the probability distribution of EUR for wells in all shale gas plays in the United States. Both distributions are described in *SI Text* and Table S4.

[vii]There is also the possibility of differences in definition of methane leakage, where some might only include methane contained in natural gas that is unintentionally released to the atmosphere (often referred to as fugitive emissions), others might additionally include methane in natural gas intentionally leaked to the atmosphere (often referred to as vented emissions), and still others might additionally include methane not just contained in leakage of natural gas but also emissions of methane from combustion or even from tanks storing coproducts (condensate or oil). For instance, Heath et al. (15) included fugitive, vented, and combustion-emitted methane in their leakage estimate, whereas Skone et al. (11) and Burnham et al. (13) only included fugitive and vented methane emissions. Harmonization to a common definition of methane leakage was beyond the scope of this study because the data were not reported at this resolution.

natural gas produced[viii] (expressed as a percent), we find that the studies evaluated here have estimated a very wide range of methane leakage, 0.66–6.2% for unconventional (mostly shale) gas and 0.53–4.7% for conventional (of different types), although less than the reported values of up to 7.9% when using alternative units (18). This wide variability represents legitimate differences in study foci (play, year, operator, etc.) based on limited available evidence about shale gas methane emissions (e.g., the current debate over how to properly convert atmospheric measurements of methane concentration into estimates of methane leakage) (43–46). Thus, methane leakage was not a parameter selected for harmonization of the estimates of life cycle GHG emissions. It should be noted that Alvarez et al. (5) estimated that on all timescales (i.e., avoiding the 20- vs. 100-y GWP debate), electricity generated from combusting natural gas could provide immediate climate benefit compared with coal if leakage rates are lower than 3.2%. New measurements of methane leakage at different scales (basin to component) are under way to improve understanding of this critical parameter (e.g., www.edf.org/methaneleakage).

Another factor that can influence the magnitude of the estimate of life cycle GHG emissions is "coproduct allocation." A common consideration in LCA (21, 47), the principle of coproduct allocation states that when there are multiple valued products from a single system, the burdens of that system should be shared among all products. Most of the eight LCAs evaluated here apportion some of the burdens of well construction and production activities to the oil produced from associated gas wells, typically implicitly for the conventional gas cases through use of EPA GHG emission estimates[ix] (11–13, 33); only four (11, 14–16) account for natural gas liquids as a coproduct of gas well production despite them being the primary economic driver of production in the price environment of 2012 and 2013 (49, 50). When the effect of coproduct allocation has been separately quantified, it has reduced GHG emissions attributable to the produced gas by 1% to ~10% (11, 14-16). A study's estimate of coproduct allocation depends on knowledge of the produced gas composition, which varies across and within basins (15, 51). Only one previous LCA has considered within-basin variability (15), concluding that the variability observed in gas composition has implications for accurate estimation of GHG emissions at source-level spatial resolution, monitoring programs, and regulatory strategies. Coproduct allocation could not be harmonized because the gas composition (besides methane content) was not reported for many studies and also because the geographic area of focus for each study differed, which would yield legitimately different gas compositions and thus coproduct allocations.

Conclusions and Recommendations. Recent research regarding life cycle GHG emissions of shale (and unconventional) gas for electricity generation has come to very different conclusions. Although drawing on common but empirically limited datasets of component-level GHG emissions, owing to differences in LCA methodological choices, system boundaries, units of analysis, included processes, and other factors, the published results of these studies are not directly comparable and span a range from ~440 to 760 g CO_2e/kWh. We performed a rigorous harmonization meta-analysis of the available literature to establish analytically consistent comparisons of estimates of life cycle GHG emissions that reflect the latest knowledge on emission-producing activities, not only for shale gas, but also conventionally produced natural gas as well as coal. Even with the greater consistency, variability in results remained owing to differences in the studies not amenable to harmonization, such as gas type and play assessed, evaluation year, methane leakage rate, and whether coproducts were included, as well as variability in assumed emission rates from activities in the natural gas supply chain. Nevertheless, after harmonization, we find that per unit electrical output, the central tendency of current estimates of GHG emissions from shale gas-generated electricity indicates life cycle emissions less than half those from coal and roughly equivalent to those from conventional natural gas. We also find that estimates of life cycle GHG emissions from the use of shale gas for electricity generation are most sensitive to emissions from the regular unloading of liquids from wells and estimates of well lifetime production (EUR).

This meta-analysis leverages previously published so-called attributional LCAs that consider the shale gas system in isolation and at an incremental (per kilowatt hour) scale. These studies do not consider global consequences of greater use of shale gas such as rebound effects that could lead to a net increase in (fossil) energy consumption (52). Ramifications of such dynamics for global GHG emissions are challenging to estimate, but should be considered when making decisions that have wide-reaching implications.

Despite the greater precision achieved through harmonization, these initial assessments of GHG emissions should be confirmed through verified measurements of emissions from components and activities throughout the natural gas supply chain, and through robust analysis of lifetime well production and the prevalence of practices to reduce emissions (e.g., from completions and liquids unloading). It is critical to aim for representativeness in sampling and data collection to ensure results reflect the diversity that exists across the industry and are resampled over time to remain relevant to this rapidly evolving industry. Attention should also be paid to robust characterization of the upper end of the distribution of emissions as these may have outsized influence on total actual emissions from a source category and yet are not currently factored into average emission factors used in inventories and LCAs. Further verification of bottom-up, component-level emission estimates by top-down atmospheric sampling can help ensure that the analytical estimates relied on for decision-making, like from LCAs, accurately reflect true emissions. Finally, natural gas used for transportation and heating should be considered in LCAs informed by measurements at the points of leakage that differ from its use for electricity generation (e.g., in NG distribution networks, after the meter in buildings, and during vehicle refueling). These points are echoed in a recent synthesis of more than 20 y of empirical study of methane emissions from natural gas systems (53).

Understanding limitations to current knowledge, this study develops a more consistent and robust foundation regarding the life cycle GHG emissions from shale gas used to generate electricity compared with conventional gas and coal. Our results are based on meta-analysis of nearly 100 LCAs, as well as the best available, updated information on key GHG-emitting activities and other influential parameters. These results can inform future analyses about the role of natural gas in climate change mitigation, policy decisions regarding air emissions, and the management of energy resources, as well as motivate further research on key issues identified here like practices and emission profiles of liquids unloading activities.

Methods

Harmonization of previously published estimates of life cycle GHG emissions from electricity generated from shale gas helps ensure fair comparisons among study results that represent the latest knowledge of industrial practice in terms of functional unit; the inclusion of all life cycle stages; inclusion of liquids unloading; inclusion and frequency of well recompletions; impact assessment metric (GWPs); and thermal efficiency of electricity generation. Some aspects that define the scope and methods of previous studies were not harmonized: gas type studied; modeling philosophy; and choice of comparison

[viii] A leakage rate reported in these units enables rapid estimation of methane emissions based on a known amount of produced natural gas.

[ix] For gas produced from oil wells, only GHG emissions starting with gas processing are assigned to the natural gas industry; the EPA assigns oil production GHG emissions, including those related to associated gas, to the oil industry (48). This approach is consistent with what is known as the product-purpose coproduct allocation philosophy (47).

case. In addition, the studies' estimates of methane leakage and coproduct allocation were also not harmonized, as discussed in *Results and Discussion.*

Harmonization of LCAs has been described and applied to many electricity generation technologies in several publications (23, 24, 54).[x] Harmonization methods as applied to conventional natural gas systems are described in O'Donoughue et al. (26). Analogous methods are applied for the shale gas LCAs evaluated here. The *Studies Contrasted* section describes harmonization of the functional unit (with further detail on the conversion of ref. 18 reported in ref. 26), GWP, and power plant thermal efficiency. Thus, this section focuses on explanation of the remaining harmonization steps applied to the eight evaluated shale gas LCAs: inclusion of missing life cycle stages (well preproduction and power plant construction and decommissioning), inclusion of important activities (recompletion and liquids unloading), and recompletion frequency adjustment. It also further elucidates harmonization steps applied to coal (23) and conventional gas (26), the two points of comparison for the results of this study.

An LCA's system boundary defines what is considered within the results reported and what was excluded. We ensured consistent system boundaries for the use of natural gas to generate electricity at the level of life cycle stage (depicted as boxes in Fig. S1). Stages missing from some of the eight shale gas LCAs evaluated here were well preproduction and power plant construction and decommissioning. Well preproduction refers to GHGs emitted from drilling and casing of a well and those embodied in all required materials and water supply and treatment. Based on review of the estimates used in studies that included this stage (10, 11, 13, 35, 55), a central estimate of 6 g CO_2e/kWh was added to studies that did not account for well preproduction. Note that well completion, which all studies included in their system boundaries, is not considered in the well preproduction stage for the purposes of this harmonization study. (Because many authors include hydraulic fracturing and completions as part of preproduction, Fig. S1 and Table S1 thus depict them.) Construction and decommissioning of a combined cycle power plant, as well as embodied materials, also emit GHGs. Although small, for completeness, the estimate of Skone and James (56) of 1.2 g CO_2e/kWh was added to studies that excluded this stage.

Although many activities contribute emissions within a life cycle stage, authors make conscious decisions about any exclusion of activities that other authors might have included, and it is generally not the role of harmonization to retrospectively second guess those decisions. As discussed above, three activities have been found to significantly contribute to life cycle GHG emissions for shale gas used to generate electricity: well completion, well recompletion, and liquids unloading. Owing to their importance, exclusion of these activities would not allow for fair and consistent comparisons. Therefore, harmonization ensured that each study accounted for them and, for well recompletion, to also reflect an update in understanding of the frequency of this practice. Other activities for which the EPA has significantly recently increased emission factors (31)—venting from centrifugal compressor wet seal degassing and conventional well completions—have been shown to have negligible impact on life cycle GHG emissions for electricity generation (11, 13, 33) and thus were not selected for harmonization. It is also outside of the scope of harmonization to alter an author's estimate of GHG emissions from an included activity because the aim is to establish consistent comparisons and not identical estimates. Furthermore, until better data become available, authors' estimates reflect legitimate differences of opinion.

In the 2011 US GHG Inventory (34), compared with previous ones, the change with the greatest impact on annual GHG emissions for the natural gas sector was an order of magnitude increase in the estimate of per-well annual emissions from venting during liquids unloading of a conventional well. The 2013 US GHG Inventory (48) reduced the estimate of emissions from liquids unloading to levels just below the annual emissions estimate used before the 2011 inventory. Motivating the reduction was publication of results of a voluntary survey from members of the API/ANGA (27), which estimated that on average liquids unloading emissions from the respondents were 93% lower than EPA's estimate developed in the 2011 GHG Inventory. This survey also established that liquids unloading is applicable to both conventional and unconventional wells, whereas the EPA had previously categorically assumed this practice applied only to conventional wells, with the shale gas LCA literature following suit.

The API/ANGA survey respondents reported data for wells that represent 26% of total US conventional and unconventional wells (27). Although it is unclear how representative this survey is of the full population of US wells, the results of this survey represent the largest set of estimates of liquids unloading publically available today. The resolution of reporting in ref. 27 allows, for the first time, for development of operator-level average estimates of annual GHG emissions per well and construction of operator-level distribution of estimates. The median of this distribution, after translation from annual emissions per well to life cycle emissions per unit generation using central estimates of EUR and well lifetime,[xi] formed our central estimate of emissions from liquids unloading: 8 g CO_2e/kWh for both unconventional and conventional wells (Table S3). Having the distribution of emissions from the API/ANGA survey allowed for the testing of sensitivity of life cycle GHG emissions to upper and lower bounds of operator-level average emissions, in addition to parametrically testing different EUR and well lifetime conditions consistent with the bounds used in the sensitivity analysis of completions and recompletions. Of note, for low EUR wells, the 84th percentile estimate of emissions reported by API/ANGA survey respondents represents the same average emissions per well developed by the EPA in their 2011 GHG Inventory (34), which is taken as the high end of our sensitivity range (0.01–202 g CO_2e/kWh). (Details of the translation of annual per well emissions reported in ref. 27 to life cycle GHG emissions and on the construction of sensitivity bounds are described in *SI Text*.)

Most of the LCAs evaluated here considered liquids unloading for their conventional gas cases, albeit using different interpretations of EPA's estimate from their 2011 GHG inventory, but two did not [Howarth et al.'s low (18) and Stephenson et al. (14)]. Three did in their unconventional cases: Howarth et al.'s high case (18), Jiang et al.'s (10) [by virtue is relying on Venkatesh et al. (33) for production emissions], and Laurenzi and Jersey (16). Also, no LCAs published before 2011 consider liquids unloading emissions. When not considered, our central estimate was added to the published life cycle GHG emissions estimate (both for the LCAs evaluated here and in ref. 26).

A well recompletion is assumed to emit the same amount of GHGs as the original completion (31). Several shale gas LCAs did not account for recompletion (10, 14, 18). To the estimates from those studies, we added an estimate of recompletion emissions based on the author's estimate of completion emissions and well lifetime adjusted by the EPA's latest estimate of frequency. With regard to the frequency of recompletions, in their final NSPS/NESHAPs rule (40), the EPA revised their estimate of the proportion of wells recompleted each year to 1% compared with 10% assumed in their 2011 GHG Inventory (34). Many of the shale gas LCAs that had included recompletions had assumed the previous 10%/y recompletion rate (11–13). Their estimate of GHG emissions from recompletions was adjusted downward to reflect the change in recompletion frequency.

For comparison with other fuel sources, we refer to recently published harmonized estimates of life cycle GHG emissions from electricity generation of several coal combustion technologies (23), as well as conventional natural gas (26). For coal, four combustion technologies (without carbon capture and sequestration) were considered: subcritical pulverized, supercritical pulverized, fluidized bed (FB), and integrated gasification combined cycle (IGCC). Thermal efficiencies representative of modern systems with all required emission controls (as of 2007) specific to each combustion technology were based on ref. 57. Harmonization of coal LCAs established consistency with regard to combustion carbon dioxide emission factor (mass of CO_2 emitted per kilowatt hour generated, which is a function of thermal efficiency, coal carbon content, and coal heating value), functional unit (to exclude electricity T&D losses), inclusion of methane emissions from coal mines, and GWPs (36). Despite use of AR4 100-y GWPs in Whitaker et al. (23), because life cycle GHG emissions for coal is, on average, only ~5% from methane, the use of ref. 23 for comparison with the natural gas LCAs here is deemed acceptable. Note that it was not possible to harmonize to the AR5 methane GWP for the conventional gas estimates in O'Donoughue et al. (26) because not enough studies reported emissions by each GHG. The error this introduces is small given that the effect of harmonizing to the AR5 GWP for the eight LCAs examined here only changed estimates of life cycle GHG emissions by 0–4%.

As for harmonization of conventional natural gas (26), harmonization steps included the following: methane GWP (to AR4 for the few studies reporting emissions by GHG), system boundary (power plant construction and decommissioning; well preproduction), inclusion of liquids unloading, functional unit (exclusion of T&D losses), thermal efficiency, fuel heating value, power plant lifetime, and capacity factor (facility annual generated electricity as a proportion of maximum annual generation). The latter three had a negligible effect and thus were not applied to the shale gas LCAs here. The same thermal efficiency for NGCC used here was used in the conventional natural gas harmonization study (51%, higher heating value basis).

[x]See www.nrel.gov/harmonization for a complete list.

[xi]The unconventional gas well EUR used here is the median for active shale plays in the United States (2.2 bcf) as determined through our analysis of EIA data (41), and well lifetime is assumed to be 30 y. Conventional gas well EUR is assumed to be 1 bcf (a central estimate from LCAs considered in this study), and well lifetime is 30 y.

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