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4 AUTHORS, INCLUDING:

Alexander T. Dale

Radisav D Vidic

University of Pittsburgh

Melissa M. Bilec

University of Pittsburgh

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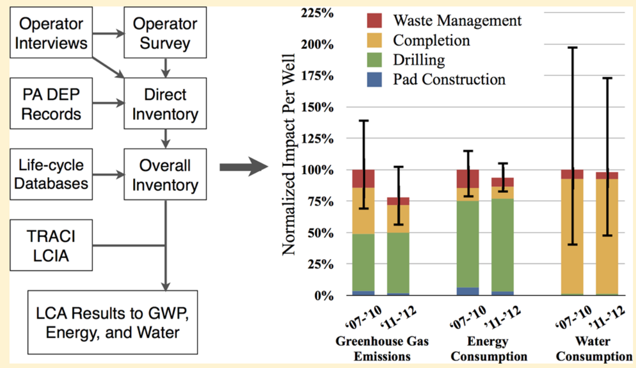
Process Based Life-Cycle Assessment of Natural Gas from the Marcellus Shale

Alexander T. Dale, Vikas Khanna, Radisav D. Vidic, and Melissa M. Bilec*

Department of Civil & Environmental Engineering, University of Pittsburgh, 742 Benedum Hall, 3700 O'Hara Street, Pittsburgh, Pennsylvania 15261, United States

Supporting Information

ABSTRACT: The Marcellus Shale (MS) represents a large potential source of energy in the form of tightly trapped natural gas (NG). Producing this NG requires the use of energy and water, and has varying environmental impacts, including greenhouse gases. One well-established tool for quantifying these impacts is life-cycle assessment (LCA). This study collected information from current operating companies to perform a process LCA of production for MS NG in three areas—greenhouse gas (GHG) emissions, energy consumption, and water consumption—under both present (2011−2012) and past (2007−2010) operating practices. Energy return on investment (EROI) was also calculated. Information was collected from current well development operators and public databases, and combined with process LCA data to calculate per-well and per-MJ delivered impacts, and with literature data on combustion for calculation of impacts on a per-kWh basis during electricity generation. Results show that GHG emissions through combustion are similar to conventional natural gas, with an EROI of 12:1 (90% confidence interval of 4:1−13:1), lower than conventional fossil fuels but higher than unconventional oil sources.



1.. INTRODUCTION

Natural gas (NG) from shale formations represents a significant source of unconventional fossil fuels. A key large US shale formation is the Marcellus Shale (MS), which underlies New York, Pennsylvania, Ohio, and West Virginia.[1] The Marcellus's overall gas-in-place reserves have been estimated to be 1500 trillion cubic feet (Tcf), with technically recoverable reserves estimated at 84 Tcf by the United States Geological Survey (USGS) in 2011, and 141 Tcf by the Energy Information Administration's (EIA) 2012 Annual Energy Outlook (AEO).[2,3] In addition, the MS is located close to pipelines and major NG markets in the northeastern US, and development of the MS and other US shale reserves may serve as models for those in other countries.

The potential for gas shales as a new source of domestic energy has incited significant scientific, political, and public discussion, with concerns raised over both the regional and global environmental impacts of extraction.[4−6] Although work has been done on how to improve the technical effectiveness of shale gas extraction,[7,8] fewer studies have been published on the environmental impacts. Osborn et al. studied methane concentrations in drinking water wells, correlating an increase in methane concentration in groundwater with proximity to drilling activity.[9] Other studies have looked at ozone and general air emissions from the Haynesville and Barnett shales, respectively,[10,11] showing significant emission increases in their respective regions. Blohm et al. have also raised the possibility that much of the MS may be unusable because of existing land use and regulation.[12]

Several studies have examined greenhouse gas (GHG) emissions of conventional and unconventional gas resources. Howarth et al.[13] reported an initial estimate with life-cycle emissions similar to coal-fired electricity. Jiang et al.[14] conducted a study of the GHG emissions of MS NG extraction using a hybrid LCA of process data and the Economic Input-Output LCA tool (EIO-LCA) and found values 11% higher than conventional NG excluding combustion but 20−50% lower than coal. Burnham et al. [15] used updated EPA estimates in conjunction with the GREET (Greenhouse gases, Regulated Emissions, and Energy use in Transportation) model,[16] with life-cycle GHG emissions 8% lower than conventional NG. Stephenson et al.[17] estimated shale gas GHG emissions to be 1.8−2.4% higher than conventional gas, while Hultman et al.[18] showed 11% higher emissions. Skone et al. performed a process-based assessment that showed shale gas with 200% higher upstream emissions, but negligible differences to end uses.[19] Most recently, Weber and Clavin[20] combined five studies to show that the ranges of GHG emissions for

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conventional and shale gas are similar per unit of hydrocarbon production.

1.1. Life-Cycle Assessment. Life-cycle assessment (LCA) is a method for quantifying impacts over the entire life cycle of a product, process, or service, from initial materials extraction (cradle) through processing (gate) and use to final disposal or recycling (grave). LCA has been codified by several organizations including the International Organization for Standardization's (ISO) 14040 set of standards,[21] and includes four distinct steps. The first step is the establishment of a functional unit and system boundaries for the stages or processes that will be included in calculations. The second step is the collection of data on all material and energy inputs and outputs for the processes within the system boundary, producing the life-cycle inventory (LCI) of stressors. This step can often have two parts—collecting direct material, energy, and transport requirements, and then collecting direct and indirect requirements from pre-existing databases. Third is the classification and characterization of stressors from the LCI into impact categories, using characterization factors that relate individual stressors to common reference units (e.g., CO_2 equivalents for GHG emissions), followed by the interpretation of results. Often these steps are iterative, with identification of high-impact materials or processes prompting additional scrutiny for those items.

1.2. Well Development Process. The processes involved in bringing shale gas to market are described in detail in the Groundwater Protection Council's Modern Shale Gas Primer,[22] with many processes that are similar to conventional gas wells. Shale-gas pads are large to accommodate necessary equipment for drilling and fracturing multiple wells from the same surface location, with individual well laterals drilled in different directions. There are commonly 4−8 wells per pad, though occasionally as many as 12 wells are drilled. Pads can be reclaimed once drilling and completion operations are finished, leaving the access road and a small area surrounding the wellheads and brine separation equipment as permanently occupied land.

An air rig is commonly used to drill vertically until the well is 150−300 m (500−1000 ft) above the shale formation. Steel casing is inserted at the surface to prevent soil from collapsing into the hole, from the surface to the base of the deepest fresh groundwater, and along the entire vertical section of the borehole. Each casing string is followed by filling the annular space with cement to isolate the well casing from the surrounding environment as a means to prevent external migration of natural gas to drinking water supplies or the surface. The transitional leg (curving from vertical to horizontal) and horizontal leg, or lateral, of a Marcellus borehole are drilled by a directional drilling rig hydraulically powered by drilling fluid. The length of a lateral varies significantly, from 450 m (1500 ft) to over 3050 m (10 000 ft).[23−25] The lateral is also cased with steel and cemented, completing the drilling and grouting processes.

Hydraulic fracturing (HF) along the lateral is a key difference in shale gas extraction as compared to conventional gas wells. The HF process uses water mixed with sand and chemicals, pumped at high downhole pressures, to fracture the shale and increase permeability, allowing gas to flow from within the fractured area to the well-bore and surface.[26] Total water usage depends on the length of the lateral and local geology but is commonly around 71 000−120 000 barrels per well.[27] This water can be from many sources including local streams, large rivers, or groundwater, and is transported to the well pad via trucks or pipeline networks.

When the downhole pressure is released, 10−30% of the injected water returns as flow-back.[22] In addition to additive chemicals, this flow-back water also contains high total dissolved solids (TDS) and possibly associated naturally occurring radioactive materials (NORMs), both from the formation itself.[28] Careful management of wastewater is critical to minimizing environmental impacts, and can utilize several methods, which have shifted over time. The simplest method is to reinject waste fluids using Class II injection wells, a common method in the Barnett Shale. However, due to unfavorable geology in much of the Marcellus shale region, there is a short supply of reinjection wells in the Marcellus. Through 2010, drilling fluids and flow-back water were often sent to municipal sewage treatment plants, diluted, and discharged into rivers. Concerns about the various ions (bromide) and NORMs in flow-back prompted the Pennsylvania Department of Environmental Protection (PA DEP) to halt this process during the summer of 2011,[29] and have led to a rise in both industrial treatment and the reuse of flow-back water for fracturing other Marcellus gas wells.

In the southwestern region of the MS, the NG contains high levels of heavier hydrocarbons.[30] This "wet gas" is processed to separate the natural gas liquids (NGL) and to regulate its heating value. NG is then compressed and sent to main transmission lines. From transmission pipelines, the fate of shale gas and conventional gas are identical.

2.. METHODS

This study focused on evaluating impacts from extracting the Marcellus Shale NG using current (2011−2012) and past (2007−2010) practices from operations in Pennsylvania. Our focus was on GHG emissions, energy consumption, water consumption, and energy return on investment (EROI). Impacts were calculated for the creation of a single producing well, and per-MJ of dry natural gas. Inventory data related to pad construction were allocated equally among the number of wells per pad for the given time period.

The bulk of the data collected was self-reported from two operators in the Marcellus play ("operators"). Initial meetings and conversations with individuals from different phases of the well development process provided a detailed background on the development of a well, including specific materials, suppliers and equipment used. These discussions identified practices which are highly variable, along with practices that have evolved or improved since drilling began in the MS. A simplified data collection table on operating practices was completed by two operators who controlled 28% of both drilling and production in the MS in PA through the end of 2011. This data table is available in the Supporting Information (SI). Fugitive methane emissions data were also collected from midstream (gas gathering and processing) companies, who process raw gas and move it to main pipelines for distribution to end users. Table 1 shows the arithmetic mean and ranges for various aspects of production based on the data from the two operators. Data collected from the operators and materials information from individual discussions were combined to create a set of direct material and energy requirements for well development.

These initial data were augmented by natural gas production and waste management information from the Pennsylvania Department of Environmental Protection (PA DEP),[31] which

Table 1. Arithmetic Mean, Maximum, and Minimum for Different Aspects of Well Development Based on Marcellus Shale Operators

time period	2007−2010			2011−2012		
process	mean	minimum	maximum	mean	minimum	maximum
Pad & Road Area (m^2)	22300	11150	29730	9480	8360	27900
Wells per Pad	3	1	9	6	1	12
Total Borehole Depth (m)	3220	2620	3930	3720	2740	4180
Lateral Length (m)	880	470	1550	1300	760	2180
Drilling Time (Days)	25	16	34	23	13	34
Fracturing Water Consumption (bbls)	150000	N/A[a]	N/A[a]	99000	42000	130000
Gas free flow time[b] (hrs)	6	1	48	6	1	24
Initial Production Rate (m^3/day)	22000	5700	85000	28000	5700	85000

[a]Only a single data point was available for water consumption in older wells via the data table. [b]Free flow refers to the period after hydraulic fracturing but before production when gas is vented, flared, or captured.

covered January 2007 to December 2012. Operators are required to self-report semiannual production and waste management data for all wells under Section 212 of the PA Oil & Gas Act.[32] Issues have been raised with the self-provided nature of the information, but the database remains the only large-scale source of per-well information, and was used in aggregate to minimize errors from individual wells. The production data were used to establish average drop-off models for long-term total production. The flow-back water management data were used to determine the percentage of flow-back managed under four major methods—injection, dilution through municipal wastewater treatment, industrial treatment, and reuse for fracturing future wells, and the average distance from well to treatment facility for each method (see Table SI-3).

Data from LCA databases were collected for each material and process used in well development—gravel, diesel consumption, water, sand, etc. Information was taken from the ecoinvent and US LCI databases for most material impacts.[33,34] LCIA was conducted using 100-year values from the Intergovernmental Panel on Climate Change (IPCC) [35] for global warming potential (GWP) and the Cumulative Energy Demand (CED) method version 1.06 for energy consumption, which includes energy consumed at all indirect stages of production.[36] *Energy consumption* was collected as MJ required for each life-cycle stage, and used to calculate both per-well energy use and energy return on investment (EROI) of delivered NG using low, average, and high volume production models. *Water consumption*, referring to water withdrawn from a body of water without replacement, was calculated, using eq 1:

$$W^{c} = (1 - \%Fb)\cdot(W^{m} - W^{r}) - W^{inj} \tag{1}$$

where W^c is water consumed, $\%Fb$ is percent of makeup water returned as flow-back, W^m is volume of makeup water, W^r is volume of water from recycled flow-back, and W^{inj} is volume injected.

Calculation of per-well life-cycle impacts was done using Monte Carlo simulation. Two million trials were run using samples from parameter distributions in conjunction with fixed LCIA data (e.g., GHG emissions per ton of steel). Triangular distributions, often used by LCA practitioners,[37,38] were used for most materials, with a log-normal distribution used for solid waste generation and normal distributions for water usage, based on data from the PA DEP and the FracFocus reporting site.[26,31] Details on distribution type and parameters are available in Table SI-1. The means of the output distributions, as well as a 90% confidence interval, were used for results reported herein. Median-based results were also calculated and are located in Tables SI-4, SI-6, and SI-8.

Calculation of impacts on a per-MJ delivered basis combined per-well impacts with a range of production estimates as described below, with all impacts from well development allocated equally per m^3 over the well's production. Per-well and processing impacts for wet gas wells were allocated based on energy content of liquids vs final dry gas.

EROI is normally calculated on the basis of thermal equivalence using eq 2—all useful energy outputs over all energy consumed, as originally defined by Hall et al.,[39,40] and specifically developed for fossil fuels by Cleveland.[41] A more recent method for calculating the EROI of fuels can be found in Murphy et al.[42] For this work, energy outputs were calculated as the estimated ultimate recovery (EUR) (see SI Section 2) less the fraction of NG either lost to leakage or used internally during processing. Energy inputs included both direct and indirect energy consumption, calculated via the CED method,[36] as well as internal process energy and the primary energy of electricity used for processing. These inputs correspond to a Level 3 system boundary as defined by Murphy et al.[42] EROI was also calculated using Monte Carlo simulations for the five different parameters. This approach generates an EROI for the expected overall lifetime of a well, omitting any additional impacts and production from future workovers. Losses are treated as reductions in output but not consumed energy.

The thermal equivalence method is useful but fails to account for differences in quality or usability, such as replacing oil with natural gas or electricity for transport. Quality-adjusted EROI methods multiply each energy source by a quality factor, λ, which can be calculated by a number of methods. This produces eq 3. We calculated EROI using both thermal equivalence and using the price-based quality-adjustment described in Cleveland,[41] which adjusts the energy from each source based on the price/MJ relative to a base energy source. Quality-adjusted EROI in this study used coal as a base price and average 2011 energy prices as reported by the EIA (See SI Section 3.3 for details).

$$EROI = \frac{\sum_{k=1}^{n} E_k^o}{\sum_{k=1}^{n} E_k^c} \tag{2}$$

$$EROI^* = \frac{\sum_{k=1}^{n} \lambda_k E_k^o}{\sum_{k=1}^{n} \lambda_k E_k^c} \tag{3}$$

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Both equations are from ref 41 with E^o representing useful energy produced and E^c representing energy consumed, for n different energy sources.

2.1. Modeling Approaches. *2.1.1. Pad Construction and Drilling.* Information on pad area, thickness, and access road lengths was collected from the two operators. Daily fuel consumption during pad construction or drilling was multiplied by the number of days required to construct a pad or drill each well. Operators reported that both air rigs and directional drilling rig pads will burn, on average, 7570 L (2000 gallons) of diesel fuel per day. The use of natural gas as a fuel for drilling or fracturing is gaining support within the broader oil and gas industry, but is still in the experimental phase for the three Marcellus operators contacted for this study.[43]

Dry cement and steel usage were based on well depth data from data tables combined with operator information on bags of cement per unit length and steel grades and weights used. All wells were assumed to have four casing strings—conductor, surface or coal casing, intermediate casing, and production casing. Based on operator reports, it was assumed that all steel arrived from Texas and Oklahoma by rail in the past, and that 20% of current steel arrived by rail from Ohio as new companies opened manufacturing facilities closer to the Marcellus.

2.1.2. Fracturing and Completions. Information on percent of water returning as flow-back (defined as the first 30 days), lifetime produced water, and production levels, and gas handling during breakthrough was collected to monitor completions impacts (for information on operator data, see Table SI-1). Because of increased public scrutiny, some well-specific information on the fracturing process is made available by a number of operators for the 2011 time period.[26] The mean values for water and sand distributions were 125 000 bbls of water and 2720 t of sand for past (2007–2010) wells, with 99 000 bbls and 1810 tons for present (2011–2012) wells. Water delivery was assumed to occur either via a network of pipeline-connected impoundments or by tanker truck. No impacts were included for water pipeline delivery. Life-cycle impacts from transportation by truck were calculated on the basis of ton-miles. 70% of water was assumed to be trucked in during the 2007–2010 time frame, and 30% was assumed to be trucked in from 2011 to 2012, as major operators brought pipeline networks into operation. Wastewater management was modeled using four separate methods: industrial treatment, reinjection, dilution through municipal treatment plants (for the 2008–2010 time frame), and reuse. Impacts for each of these methods were calculated, and PA DEP data was used to determine the proportion managed under each method. Details on modeling these methods and impacts per barrel can be found in SI Section 1.2.

Information was collected on the percentage of wells that were vented, flared, or captured during completion, and average time of gas flow before the well was capped or put into production. This initial gas is the subject of many assumptions in the literature due to methane's high GWP,[13−15,44] and was calculated here based on a uniform distribution for free-flow time combined with a triangular distribution of initial flow rate which ranged from initial production levels to an order of magnitude lower.

2.1.3. Production and Processing. Production levels were calculated using regression models based on PA DEP data for per-well production.[31] PA DEP data are available on an annual basis for 2007–2009, and every six months for 2010–2012. Wells which started production in 2008–2011 had their production data for each available time period fit to a power model and used to calculate total production over 30 years for each well. The 1571 DEP records generated an overall log-normal data set. EUR for the 2008–2010 time frame was calculated with a mean of 72 million m^3 (mcm) and a 90% confidence interval of 0.7 and 221 mcm. For the 2011–2012 time frame, only wells that began production in 2011 were used, producing a mean of 108 mcm and 90% confidence interval of 1.8 and 304 mcm. See SI Section 3 for details on EUR calculations.

Four primary steps between well-pad and distribution for use were considered—leakage during initial gas processing and midstream transportation, processing to remove liquids when necessary, compression for long-distance transportation, and leakage during transmission. Based on conversations with a major midstream processor and similar studies,[20,30] midstream leakage was assumed to be 1.1% of total volume for past practices, and 1% for current ones due to increased usage of vapor recovery units on condensate tanks.[45] Processing to remove NGL was modeled using an electrically powered dry gas processing module in the ecoinvent database.[33] This module shows a 1.2% energy loss relative to the energy in the output NG. Allocation of impacts for preprocessing impacts of wet gas from southwestern PA was done based on energy content, resulting in an average 75%/25% allocation for natural gas vs liquids. The transport and delivery of NGL was not modeled in this study. Energy consumption for compression from regional gathering plants to the main transmission pipelines was assumed to be gas-powered and was modeled using operator information for actual compressors used in PA. The two relevant compressors are operated using pipeline gas, consuming an average of 3.5% of the natural gas as a parasitic load.[46,47] No compressors were modeled for regional gathering plants.

2.2. Uncertainty and Sensitivity Analysis. With many different operators working in a still-developing area, there are a wide variety of operating practices, creating significant uncertainty about long-term production levels and additional fracturing operations. Calculating initial results on a per-well basis minimizes uncertainty from production levels for per-well results, but for impacts per MJ of gas delivered, production values are required. The use of Monte Carlo methods to generate per-well impacts and the use of distributions in calculating production values allow results to be reported as percentiles rather than minima and maxima.

Validation of an LCA based on operator-provided data and comparison of our results to others is critical. Our LCA results were compared to published studies that focused on MS impacts, along with studies that looked at conventional NG.[14,15,20,48,49] The primary comparisons were to ref 14 in which many of their calculations were performed using a hybrid LCA method, and ref 15 in which the GREET model and EPA estimates of fugitive methane were used. Comparing our purely process-based LCA results with these two studies provided different methods and data sets for calculating similar impacts.

3.. RESULTS AND DISCUSSION

Results on a per-well and per-MJ basis are discussed below. Per-MJ results focus on per-kWh impacts and EROI. The results indicate that the life-cycle GHG emissions of MS NG appears similar to conventional NG, with a lower EROI. Results below are based on processes and data for the Marcellus Shale, and are not necessarily applicable to other shale formations. Uncertainties are provided at a 90% confidence interval. The context of these results and broader questions about the use of shale gas are discussed in Section 3.4.

3.1. Environmental Impacts Per Well. Results on a per-well basis in three impact categories (greenhouse gas emissions, energy consumption, water consumption) are organized by stage and normalized to mean impacts for a well during the 2007−2010 time frame, as shown in Figure 1. These results are not allocated to dry natural gas and liquids, and represent only the materials and energy required to create a single active well, regardless of long-term production. The values shown are for the mean of the final Monte Carlo distributions, with error bars showing 90% of the distribution. These results show that a 2011−2012 well has mean impacts of 2.2×10^6 kg CO_2-eq, 2.2×10^7 MJ of primary energy, and consumption of 8.2×10^4 barrels of water. Mean impacts for GHG emissions and energy decreased by 22% and 6%, respectively, while per-well water consumption showed only a 2% decrease with high per-well uncertainty. Because the operator data underlying these differences is limited, changes should be interpreted with caution.

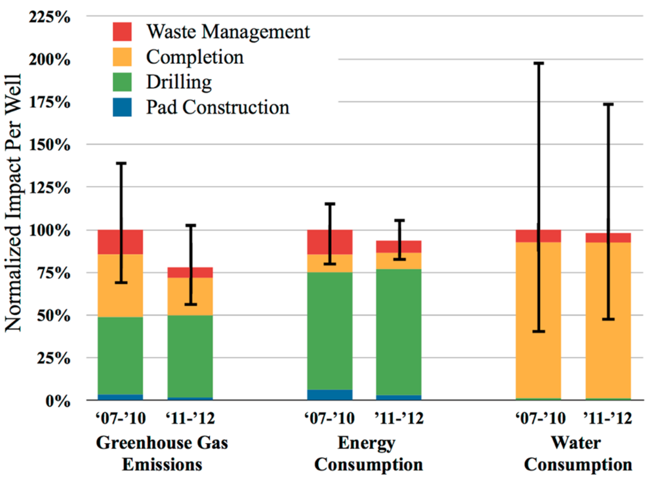

Figure 1. Phase contributions to per-well greenhouse gas emissions, energy consumption, and water consumption. Waste management includes solid waste and average impacts from wastewater practices. No allocation based on production or liquids content. Values are shown for a well with mean impacts, with error bars denoting a 90% confidence interval, and are normalized to the impacts in the 2007−2010 time frame for each case.

Impacts due to diesel consumption and drilling materials—steel for casings and cement—show minimal change between time periods. Improvements in operations have not resulted in faster well drilling or more efficient drills, and casing requirements have remained constant or increased, as expected with longer laterals. Although some materials such as steel are now manufactured more locally, the decrease in transport impacts is offset by an increase in average lateral length which requires additional materials. Increased material usage increases per-well impacts, but is offset by higher total production and lower per-MJ impacts.

These results show decreases in GHG emissions in several stages of well development. Lower impacts in the small fraction of impacts from pad construction are due to smaller pad sizes and an increase in the number of wells per pad. Lower waste management impacts come from reduced use of industrial treatment or municipal treatment plants and increased water reuse or injection, options with lower impacts per barrel. While gas was vented or flared for many early MS wells, practices are shifting toward capturing the gas as soon as possible, with flaring as a backup and venting as a last resort. This shift is mandated by an EPA rule which requires full compliance by 2015.[50] These practices reduce the release of methane and its associated GWP. Energy shows similar decreases in pad construction and waste management impacts, but the changes in completion processes do not affect energy usage. In addition, with the trend toward longer laterals and resulting increased drilling time, the energy consumption and GHG emissions during drilling increased slightly between the early development and modern times.

Water usage was approximately the same on a per-well basis between the two time periods examined. Although improved fracturing processes have reduced the amount of water on a per-stage basis, longer laterals and additional fracturing stages nullify these improvements in our results. However, changes to flow-back management mean more water is reused and less is permanently disposed of in injection wells.

3.2. Environmental Impacts per MJ Delivered. Per-well impact data were combined with estimates of lifetime *per-well production* to calculate total development impacts on a per-MJ basis. While wells are similar during development (as in the impacts in Section 3.1), high-performing wells contribute a disproportionate percentage of total production (see SI Section 2 for details). The use of mean—rather than median—production was selected in order to represent the 'average' volume of gas, which is more likely to be from a high-performance well. Results calculated using median estimates are available in Table SI-8. Additional data on impacts from gas processing, distribution, and combustion from refs 20 and 51 were added to include stages through delivery to customers. The per-MJ results show the relative importance of mid- and downstream processes, which contributed 96% of precombustion GHG emissions and 95% of precombustion energy consumption. Detailed values and confidence intervals can be found in Table SI-8. These mid- and downstream processes are similar to conventional wells, reducing any shift in impacts from unconventional well development practices, or differences between past and present time periods. In addition, increases in pad spacing, while not visible on a per-well basis, will also tend to reduce the land area per unit energy, an environmental metric not investigated in detail in this work.

3.2.1. GHG emissions from Electricity Generation. The per-MJ environmental impacts, allocated by energy content between dry gas and liquids where necessary, were combined with literature data on combustion emissions to calculate GHG emissions for natural gas combined cycle technologies per kWh of electricity. These results are compared for a combined cycle plant at 49% efficiency, and pulverized coal at 37% efficiency in Figure 2. The large confidence interval is a result of the wide range of production values from shale gas wells, with a spread of 2 orders of magnitude between the 5th and 95th percentiles.

All three shale gas studies (this work, refs 14,15) report results which are similar to each other and significantly lower than those reported in ref 13, a report which has been critically examined by several studies.[17,20,52] The primary difference in the Howarth study[13] is due to information on gas handling during completion collected in this study, which led to our assumption that a lower volume of fugitive gas was released and

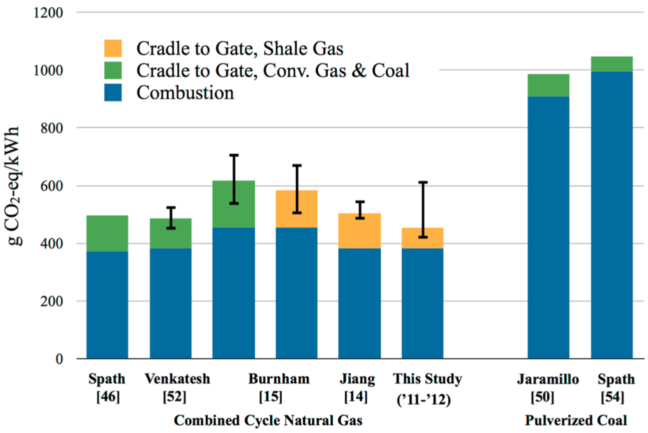

Figure 2. Per kWh comparison for GHG emissions of shale gas in a combined cycle plant (47% efficiency) relative to other conventional and shale gas studies and pulverized coal. Error bars are: Venkatesh, high and low estimates;[51] Burnham, 80% CI;[15] Jiang, high and low production scenarios;[14] this study, 90% CI, with the midpoint based on mean production. Combustion information from ref 51 and other studies from refs 48,49,53.

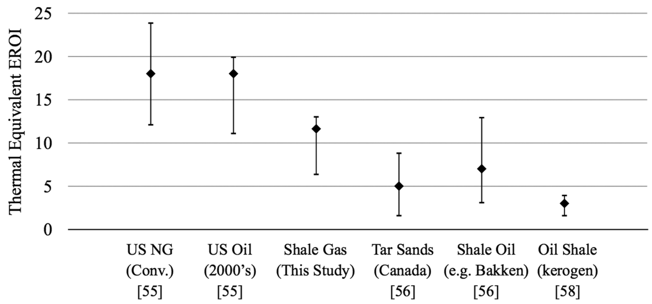

Figure 3. EROI of various hydrocarbon sources, all in thermal equivalent values. Coal is not shown for clarity as its thermal EROI has been reported at 40:1 to 80:1.[56] The results from this study show a 90% CI and are unbalanced because of the processing energy acting as an upper bound, and the potential for very low-performing wells. These values are not directly comparable with electricity sources. US NG, US Oil from ref 54, Tar sands and shale oil values from ref 55, oil shale values from ref 57. Quality-adjusted EROI was also calculated and is available in SI Section 3.3.

a much higher percentage of wells were flared or captured rather than vented. This shift in assumptions from Howarth et al. is shared by the other two studies and coincides well with operator reports, though it is clear that more study on leaked methane is critical.[44]

In addition, although the primary process differences between shale gas and conventional gas occur during well development, these well development processes represent 1% of life-cycle GHG emissions (see Table SI-8). Efforts to reduce the environmental impacts of natural gas—conventional or unconventional—will see larger gains via efforts around efficient midstream processes, combustion, and use rather than well development practices. Other constraints or impacts, including new safety regulations, landowner preference, public health, and public opinion may dictate a greater focus on drilling and completion practices.

3.2.2. Energy Consumption and EROI. The thermally equivalent EROI was calculated for shale gas at point of delivery, considering production, processing, compression, and transmission, but not combustion. With an average 1.1% loss from leakage during midstream processing, use of 1.2% of total energy content in the form of electricity during liquids removal for wet gas, and 3.5% parasitic loss from compression, the thermal EROI for delivered gas from an average Marcellus well was found to be 12:1 with a range from 4 to 13:1. The large range is a result of high uncertainty in production rates, while the similar mean and 95th percentile are the results of the upper bound set by processing and compressive energy consumption. EROI is primarily dependent on the amount of NG used in processing and compression, with a weaker dependence on leakage, which affects delivered quantity rather than consumed energy. Processing and compression are not unique to shale gas. Calculated thermal EROI is shown against other fossil fuels in Figure 3. The thermal EROI of coal has been reported as a range from 40:1 to 80:1, higher than any modern NG or petroleum energy source.[54] A value of 12:1 places shale gas in an unfavorable position relative to conventional fossil fuels,[54] but a favorable position relative to other unconventional oil and gas reserves such as the Athabascan tar sands or the Bakken shale oil formation.[55] Additional estimates of shale gas EROI would be beneficial. For calculation and discussion of quality-adjusted EROI, see SI Section 3.3

Whether EROI of shale gas is rising or falling is key for planning the use of the resource. Others have noted that EROI of energy resources tends to fall over time as the easiest sources are captured first.[41,54] Comparing the average daily production for new wells on a month-by-month basis shows that there is no trend in year-to-year production (Table SI-7). Increases in daily production might be attributed to the use of longer laterals as well as improvements in fracturing methods as operators adapt to local geological conditions. Additional long-term data is needed before trends between production and EROI can be determined.

3.3. Water Consumption. Water usage and management varies significantly by company. In terms of absolute quantity of water required per well, some operators reported decreases of up to 45% between past and present operating practices, but no notable change in water usage was visible across many operators' data. The volume used is related to both efficiency per fracturing stage, and lateral length, which is not always available. Water consumption for shale gas has been estimated[58] at 4.4×10^{-3} L/MJ, and was found to be one of the lowest unconventional sources in terms of water intensity.

The growing practice of reusing flow-back and produced water for fracturing will likely reduce the amount of freshwater required, but these gains may be limited. Although some larger operators are reusing 33−85% of their wastewater volume to offset freshwater requirements, this volume is limited to the 15−30% of water consumed which is returned as flow-back. In addition, if the number of wells drilled per year increases, the reused water and associated reduction in freshwater requirements is, overall, allocated among several wells, reducing the offset volume further. Operators may be recycling some of their wastewater, but because of flow-back rates and increased drilling, this practice only results in ~20% lower freshwater requirements. Even if drilling rates level off, the buildup of TDS in reused water may lead to an increase in injection volumes rather than recycled water, again limiting freshwater requirements.

Finally, in the life-cycle of natural gas, burning natural gas does produce water as a byproduct.[59] However, this water does not immediately or necessarily fall within the same watershed it

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was withdrawn from for makeup water, and therefore does not offset total water consumption. With the rise of large-scale reuse of wastewater and more robust water pipeline and storage networks, high-level concerns over water consumption, at least in the relatively water-rich states which overlie the Marcellus, should be focused on excessive withdrawals from specific bodies of water or during specific times rather than overall quantity used for fracturing.

3.4. Broader Relevance. Relative to other unconventional sources of oil and gas, our results show that the Marcellus Shale's impacts to GHG emissions, energy consumption, and water consumption do not represent a reordering of natural gas from shale relative to impacts of other fossil fuels. This is not to say that the rise of the shale gas is a clear long-term option. Shale gas may represent a decrease in some emissions relative to coal, but it remains insufficient in meeting scientific mitigation goals for global carbon emissions.[60,61] In addition, there are many other impacts which require consideration, including public health, ecosystem damage, and environmental toxicity. These issues have not been addressed in this paper, but are essential for sound policy development. This study helps to emphasize the large uncertainties that are still present at various points of the shale gas life cycle, and the need to collect data beyond the impacts considered here.

The Marcellus as a whole represents roughly half of US shale gas reserves,[22] and is geographically close to major NG markets. The per-well production rates and quality of well sites are important signals for the development of the play. While wells in the MS have shown oscillation in daily production rates rather than steady increases or decreases (see Table SI-7), the availability of surface rights to place well pads may be as much of a limiting factor on total extractable reserves as geological conditions.[12] The long times to prepare, drill, and complete a well, combined with low NG prices depressing drilling rates in much of the MS, may delay the appearance of decreased per-well production rates on a play-wide basis.

While individual impacts are of significant consequence to landowners and surrounding communities, and must be assessed and minimized going forward, in a wider context the Marcellus shale requires a higher-level approach to impact calculation and policy creation because its practices and development will be a model for shale gas formations worldwide. A final policy question is whether shale gas resources will be used as a transitional energy source while renewable energy sources are actively expanded, or whether their use will transform the economy from one dependent on oil and coal to one which is dependent on natural gas.

■ ASSOCIATED CONTENT

Ⓢ Supporting Information

Information on parameters used for per-well results, calculation procedures for EUR and EROI, and mean and median results at both per-well and per-MJ levels. This material is available free of charge via the Internet at http://pubs.acs.org.

■ AUTHOR INFORMATION

Corresponding Author

*E-mail: mbilec@pitt.edu. Phone: 412 648-8075.

Notes

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