

A Preliminary Energy Return on Investment Analysis of Natural Gas from the Marcellus Shale

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Supporting information is available on the JIE Web site

Summary

An analysis of the energy return on investment (EROI) of natural gas obtained from horizontal, hydraulically fractured wells in the Marcellus Shale was conducted using net external energy ratio methodology and available data and estimates of energy inputs and outputs. Used as sources of input data were estimates of carbon dioxide and nitrogen oxides emitted from the gas extraction processes, as well as fuel-use reports from industry and other sources. Estimates of quantities of materials used and the associated embodied energy as well as other energy-using steps were also developed from available data. Total input energy was compared with the energy expected to be made available to end users of the natural gas produced from a typical Marcellus well. The analysis indicates that the EROI of a typical well is likely between 64:1 and 112:1, with a mean of approximately 85:1. This range assumes an estimated ultimate recovery (EUR) of 3.0 billion cubic feet (Bcf) per well. EROI values are directly proportionate to EUR values. If the EUR is greater or lesser than 3 Bcf, the EROI would be proportionately higher or lower. EROI is also sensitive to the energy used or embedded in gathering and transmission pipelines and associated infrastructure and energy used for their construction, energy consumed in well drilling and well completion, and energy used for wastewater treatment.

Introduction

A valuable measure of a fuel's usefulness and long-term viability is its energy return on (energy) investment (EROI). This is the ratio of the energy value of that fuel as it is made available in its usable state to the energy invested to bring that fuel to its point of use (Heinberg 2009; Mulder and Hagens 2008; Murphy et al. 2011). A number of studies on the EROI of oil and gas were conducted in the 1970s and 1980s, but there has been little recent work (Hall 2011). EROI is related to the concept of net energy, as developed by Howard Odum and others, and to the concept of life cycle assessment (Odum 1973a, 1973b). In the face of recent increases in prices of fuels, particularly petroleum and its refined products, EROI studies are again being conducted. Unfortunately, rigorous analyses of the EROI of

at least one fuel, ethanol derived from corn, have come too late to prevent the development of a large industry based on a fuel that appears to offer relatively little EROI (Farrell et al. 2006; Pimentel 2003; Pimentel and Patzek 2005). There are other concerns besides energy that are involved in the development of energy sources. For example, the ethanol industry was developed, in part, due to its benefits in terms of farm support and employment in affected states.

In the early days of petroleum and natural gas production, when wells were shallower and readily accessible by land routes, EROIs of petroleum were probably in the range of 100:1 (Hall 2008). Few data exist, however, on early EROIs. Values above 10,000 are possible for flush production of enormous wells, so-called "gushers." To the extent that the growth of industrial society has been supported by readily available and cheap energy

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(i.e., fossil fuels [FFs] with high EROI), industrial economies will be increasingly stressed as easily extracted fuels are used up and replaced by fuels with lower EROI. Some analyses suggest that an EROI greater than 5:1 to 10:1 is necessary for even a limited functioning of industrial civilization and indicate that many of the newer oil wells in difficult locations (e.g., deep seas) have EROIs in the range of 10 (Hall 2008). One recent study indicates that the average EROI of the discovery and production of petroleum and natural gas combined in the United States has shown a general decline during the period of 1919–2007 (Guilford et al. 2011). Two recent studies have found declining EROIs; one found that the average EROI for global oil and gas production combined, at the wellhead, declined from 26:1 in 1992 to 18:1 in 2006 (Gagnon et al. 2009), whereas another found that the EROI of conventional natural gas production in Canada declined from 38:1 in 1993 to 15:1 by 2005 (Freise 2011). Large declines in EROIs have been noted by Brandt (2011) for petroleum production in California due to the use of thermal recovery techniques.

However, some gas plays have a higher EROI; vertical tight gas wells in the Appalachian basin in Pennsylvania, which are typically hydraulically fractured, have been found to have an EROI in the range of 67:1 to 120:1 (Sell et al. 2011). (A “play” is a known or postulated gas or oil accumulation sharing similar geologic, geographic, and temporal properties.) EROI values as high as this appear consistent with a recent study of life cycle greenhouse gas (GHG) emissions of Marcellus Shale gas (Jiang et al. 2011). This study found that greenhouse impacts from pre-production activities, including well drilling and completion, much of which are from combustion and thus related to energy consumption, are low compared to the GHG emissions from the combustion of the total quantity of gas produced by a well.

Ultimately, it seems inevitable that fuels and energy sources with higher energy inputs relative to energy supplied will cost more per unit of energy. However, as recent experience with corn-based ethanol indicates, there is no guarantee that market signals will be transmitted soon or clearly enough to encourage advancement of fuels or other energy sources with the best EROI and discourage those with poor EROI. Studies of the EROI of alternative energy sources and new sources of petroleum and natural gas could contribute to the development of policies and planning approaches that will favor the best-performing fuels and energy sources. Other aspects of fuels and energy sources, such as economic factors and significant environmental or social impacts, may also be important and should be considered along with their EROI (Heinberg 2009; Leach 1975).

For an EROI analysis to be useful, it must be comprehensive enough to include key energy inputs and outputs, and its inclusions and boundaries must be clearly stated. Unfortunately, there appears to be no set definition of EROI. To the limited extent that EROI studies have been carried out on new and emerging fuels and energy sources, they have typically been characterized by inconsistent methodologies (Murphy et al. 2011; Brandt and Dale 2011).

A new source of natural gas is organic-rich shale, including the Barnett, Haynesville, Fayetteville, and Woodford shales in

a region including Texas, Oklahoma, Arkansas, and Louisiana, the Bakken Shale in North Dakota, and the Marcellus Shale in Pennsylvania, West Virginia, and New York, as well as nearby contiguous regions. These shales appear to offer the promise of a large, new source of this fuel.

“Proven reserves” in the Marcellus Shale are currently estimated as approximately 13.2 trillion cubic feet (Tcf)¹ (EIA 2012). Proven reserves represent the portion of the total resource that is essentially connected to distribution systems and ready to produce. This portion is a subset of successively larger portions termed “economically recoverable resource,” “technically recoverable resource,” and “resource in place.” Resource in place is a highly uncertain quantity. Whatever this quantity is, it will not change physically over time, although it may be better characterized and thus estimates may change. The other three portions will grow over time to the degree that technology advances and/or prices increase.

Estimates of the technically recoverable natural gas resource of the Marcellus Shale have varied considerably in the recent past. As of 2002, the U.S. Geological Survey (USGS) estimated this at 2 Tcf (Urbina 2011). However, this quantity was based on the technology of that time, which produced gas by drilling and extracting it from “traps,” which are folds and pockets in sandstone layers. The gas in traps is believed to have seeped out of underlying shale layers known to contain gas, so-called “source rock” (Lavelle 2010). In 2003, two techniques previously used separately, hydraulic fracturing and horizontal drilling, were combined and used with success to tap into the methane trapped within the Barnett Shale. During the period from 2004 to 2008, the same approach was adapted by industry for use in the Marcellus Shale, and it was found that, through this approach, the Marcellus Shale could produce natural gas at a rate greater than conventional Pennsylvania wells (Lavelle 2010).

Horizontal drilling intersects naturally occurring vertical fractures, and hydraulic fracturing creates more fractures and accesses more pore spaces (King 2012). Hydraulic fracturing involves pumping fluid and a propping agent, such as sand, down the wellbore under high pressure to create fractures in the hydrocarbon-bearing rock (NYDEC 2011). The propping agent, or proppant, keeps the fractures open, which allows the natural gas to escape up the wellbore (NYDEC 2011). The fluid and proppant that is pumped into the wells is comprised of over 98% sand and water, but also contains chemical additives (NETL 2009).

Since this technological advance, new estimates of the technically recoverable resource of the Marcellus Shale have been developed. One study, which assumed a 50-year production period per well, estimated there to be a 90% probability that the technically recoverable resource totals at least 220 Tcf, a 50% probability that it totals at least 489 Tcf, and a 10% chance that the total is 867 Tcf or more (Engelder 2009). In April 2011, the U.S. Energy Information Administration (EIA) stated that the Marcellus Shale has an estimated technically recoverable resource base of about 400 Tcf (EIA 2011b). A more recent USGS (2011) estimate is that the technically recoverable

resource of the Marcellus Shale is 43 Tcf of natural gas at 95% probability, 84 Tcf of natural gas at 50% probability, and 114 Tcf at 5% probability, as well as 3.4 billion barrels of natural gas liquids (USGS 2011; Nelder 2011). Even this lower USGS estimate represents a substantial resource, especially if most of it is extracted over the next several decades. In 2010, U.S. total natural gas consumption was approximately 23.8 Tcf (EIA 2011a).

Initial production quantities from the Marcellus Shale appear promising. However, production potential and initial production quantities of an energy resource are not, by themselves, sufficient reason to encourage the development of that resource. Among the numerous environmental and economic factors that should be considered is a valid picture of the EROI of a resource that is based, as closely as possible, on actual measurements of energy inputs and outputs. So far, no studies on the EROI of natural gas extracted from the Marcellus Shale, or any other of the shale plays, have appeared in the literature.

The development of an EROI for natural gas extracted from an average horizontal hydraulically fractured well in the Marcellus Shale has been attempted and is described herein. Other factors are important regarding the development of energy sources, including potential environmental issues. Various studies have addressed some of these issues as they apply to the extraction of gas from the Marcellus Shale. We have confined our analysis to assessing the EROI of this process.

Methodology

The methodology used has been based, in large part, on a bottom-up protocol described by Murphy and colleagues (2011) and fits the pattern of what Brandt and Dale (2011) term a net external energy ratio (NEER). These authors discuss four different mathematical forms of energy return ratios for energy extraction and conversion pathways. These are the net energy ratio (NER), the net external energy ratio (NEER), the gross energy ratio, and the gross external energy ratio. The NER has, as its numerator, the net output of refined energy to society and, as its denominator, the sum of all energy consumed in the energy production and refining process. In contrast, the NEER's denominator includes only those inputs that are consumed from the existing industrial energy system, excluding any "self-use" (e.g., produced natural gas used to process and compress produced gas). Brandt and Dale note that the NER is a more comprehensive measure of the total energy return from a production pathway and can be expected to correlate closely with environmental impacts, such as greenhouse emissions, of a pathway. Conversely, the NEER is a more useful measure of the contribution of an energy source to the energy supply of society because it counts only the inputs that must be produced and delivered externally through the existing energy supply system. The NEER form used herein is consistent with a recent study by Sell and colleagues (2011). These authors provide the relationship, as shown in equation (1),

$$\text{EROI} = (P - s)/(S + C + p + D) \quad (1)$$

Table 1 Data elements included in analysis

<i>Activity or material Input</i>
Drilling rig mobilization, site prep, demobilization
a) Transportation
b) Drill pad and road construction
Well drilling (single, horizontal)
a) Drilling engine(s) operation
b) Oil-based drilling mud
Completion rig mobilization and demobilization
Well completion (single, horizontal)
a) Transportation, including hauling of water and materials for hydraulic fracturing
b) Hydrofracturing pump engines operation
c) Rig engines operation
d) Site reclamation
e) Transportation for site reclamation
Steel for well casing (embodied energy)
Concrete for well casing (embodied energy)
On-site engines and similar equipment (embodied energy)
Steel and construction for associated necessary pipelines (embodied energy)
Chemicals and proppant used in hydrofracturing (embodied energy)
Production brine removal associated with routine well operations, transportation (energy consumed)
Wastewater treatment, energy consumed
Electricity used for natural gas compression
<i>Output</i>
Compressed natural gas delivered to users, after subtracting natural gas used for compression and processing

where P is production, s is shrinkage, and the (S + C + p + D) denominator represents steel, cement, proppant, and diesel fuel, which, they say, represent the chief energy inputs of the extraction effort. The s, or "shrinkage," term represents energy used for processing the extracted gas, which the authors consider to be approximately 4% of the total quantity of gas. In this work, we have used the same basic formula. We have subtracted the self-use natural gas that is used to process and compress the produced gas from the total of the produced gas and divided this quantity by the sum of the chief external energy inputs.

The specific activities, steps within these activities, and material inputs and outputs considered in this analysis are listed in table 1.

The formula for the EROI calculation performed in this work is as shown in equation (2),

$$\text{EROI} = (P - s)/(wdc + sc + cc + en + scp + cp + br + wwt + etd) \quad (2)$$

where

- P = cumulative production, also termed estimated ultimate recovery (EUR),
- s = self-use of 8.2% of the produced gas for processing and compression,

wdc = energy used in well drilling and completion, including hydrofracturing and transportation
 sc = embedded energy of steel used for casing,
 cc = embedded energy of cement used for casing,
 en = embedded energy of engines used on-site,
 scp = embedded energy of steel and energy used for construction of necessary pipelines,
 cp = embedded energy of chemicals and proppant,
 br = energy used over lifetime of well for brine removal,
 www = energy used for wastewater treatment, including transportation, and
 etd = electricity used for transmission and distribution of produced gas.

Conversion factors used are provided in the Supporting Information on the Web.

Results

The energy values for each significant activity or material input are shown in table 2.

Values in table 2, except as noted, are averages of ranges of estimates available. The mean estimate of total input energy for a typical Marcellus well is 36.7×10^3 gigajoules (GJ). Three of the less-certain input energy values, (1) energy used or embedded in gathering and transmission pipelines and associated infrastructure and construction, (2) energy consumed in the drilling and well completion processes, and (3) energy used for wastewater treatment, contribute the most uncertainty to the input energy EROI estimate (see figure 1). Figure 1 shows the differences between the high and low values of the estimates for the parameters shown, as indicated in the notes to table 2, as compared with the average estimates of these parameters that are provided in table 2.

Additional uncertainty exists for the output quantity, or EUR. Several estimates of the mean EUR of a Marcellus well have been reported. One study analyzed early production data for 50 Marcellus wells and concluded that the 50th percentile production rate was nearly identical with values reported as typical by industry, suggesting that the EUR for the average Marcellus well is 3.75 Bcf (Engelder 2009). This value is in substantial agreement with the 3- to 5-Bcf range suggested as likely by the U.S. Department of Energy National Energy Technology Laboratory (Skone 2012) and with a range of 3.75 to 7.0 Bcf suggested by another analysis (Vandeman 2011). These values are based on the assumption that the useful life of a well will be 30 years. Another study, based on several references, assumed that a typical Marcellus well would produce 2.7 Bcf, and noted that considerable uncertainty exists regarding well production rates and lifetimes (Jiang et al. 2011). Another study estimated that the mean ultimate recovery for wells in the "interior Marcellus" region is 1.158 Bcf (USGS 2012).

In an effort to provide perspective on these reported EUR values, data collected and made public by the Pennsylvania Department of Environmental Protection (PA DEP) (2012) was reviewed and analyzed. These data include production totals

and days of production from Pennsylvania gas wells for five different periods, the one-year period from July 2009 through June 2010, and the six-month periods from July 2010 through December 2010, January 2011 through June 2011, July 2011 through December 2011, and January 2012 through June 2012.

In this analysis, production totals for active Marcellus horizontal wells were downloaded from the database, and the 343 wells that reported production for less than 365 days for the first period and production during each of the remaining periods were selected. These wells were considered to represent the only wells for which the data provided a complete record of that well's production, because if a well had 365 or more days of production for the first period, it may have begun production before that period. Wells with fewer than 182 or 183 days of production in the later periods were included based on information that wells are typically shut in for a few days every six months for maintenance, and sometimes are shut in for longer times due to various actions such as installation of compression systems, hydrofracturing an adjacent or nearby well, or lack of pipeline capacity to handle the total production (Bolander 2012; Paterson 2012b). The PA DEP states that incomplete or inaccurate data are possibly present in the database; well data are as received; staff limitations have, so far, prevented checking and follow-up for the bulk of the data (Suchodolski 2011).

Cumulative production totals versus cumulative days of production were determined for each of the 343 wells. A curve-fitting program, XLfit (XLfit 2012), was used to identify best-fitting curve forms for the plot of cumulative production for each period for the average of all 343 wells. The fitting process was purely empirical and involved no assumptions about theoretical bases for one function or another. The best-fitting curve was of the form of equation (3), which is curve #251 in the XLfit program:

$$y = (D + ((A * (x^C)) / ((x^C) + (B^C)))) \quad (3)$$

where

y = cumulative production,
 x = cumulative days of production, and

A, B, C, and D are constants derived by the curve-fitting program.

This equation form fit the average of all cumulative production curves with an R^2 value approaching 1. Next, a group of 20 of the 343 wells was selected at random, and the best-fitting curve of this same form was determined for each well. The A, B, C, and D values for these best-fitting equations were then used with the equation as shown above to project the cumulative production total at 30 years for each of these 20 wells. A 30-year production period was chosen as likely to be typical (Skone 2012). Plots of the cumulative production data for each of the 20 wells and the average of all 343 wells, and projections out to two different time periods, are shown as figures 2 and 3.

In figures 2 and 3, solid lines represent reported production data, dotted lines represent projections based on the best-fitting equation of the form noted above, and the line with dark circles represents the average cumulative production for all 343 wells.

Table 2 Input energy values

<i>Activity or Material Input</i>	<i>Short Tons CO₂^a</i>	<i>Gallons diesel^a</i>	<i>Metric tons NO_x^d</i>	<i>GJ equivalent</i>	<i>Average of estimates, subtotals, GJ</i>	<i>Average of estimates, totals, GJ</i>
Drilling rig mobilization, site prep, demobilization						
a) Transportation		432		63		
b) Drill pad and road construction	11			144		
Well drilling (single, horizontal)						
a) Transportation		2,298		333		
b) Power engines	168			2,197		
c) Oil-based mud		8,000 ^b		116 ^b		
Well drilling total, based on CO ₂ and fuel-use reports ^a				2,852		
Well drilling total based on NO _x emissions study, not including transportation			5.5	4,581		
Well drilling total based on NO _x emissions study, including half of the transportation total ^d				5,588		
Well drilling total, average of estimated values					4,220	
Completion rig mobilization and demobilization		432		63		
Well completion (single, horizontal)						
a) Transportation		2,462		357		
b) Fracking pump engines operation		43,500 ^c		6,301		
c) Rig engines operation	7			92		
d) Site reclamation	6			78		
e) Transportation for site reclamation		268		39		
f) Production equipment installation, transportation	1			13		
Well completion total, based on CO ₂ and fuel-use reports ^a				6,942		
Well completion total, based on NO _x emissions study, not including transportation			2.25	1,874		
Well completion total based on NO _x emissions study, including half of the transportation total ^d				2,765		
All transportation for well drilling and completion, based on NO _x emissions study			2.14	1,782		
Well completion total, average of estimated values					4,854	
1) Well drilling and completion, grand total, average of estimated values						9,073
2) Steel for well casing, (embodied energy)						3,874 ^e
3) Cement for well casing, (embodied energy)						1,070 ^f
4) On-site engines and similar equipment, (embodied energy)						907 ^g
5) Steel (embodied energy) and construction for pipelines; construction portion is mid-point of range of estimates						9,637 ^h
6) Hydrofracturing chemicals and proppant (embodied energy)						4,416 ⁱ

(Continued)

Table 2 Continued

Activity or Material Input	Short Tons CO ₂ ^a	Gallons diesel ^f	Metric tons NOx ^d	GJ equivalent	Average of estimates, subtotals, GJ	Average of estimates, totals, GJ
7) Production brine removal, transportation, 30 years	90					1,177 ^a
8) Wastewater treatment, energy consumed, mid-point of range of estimates						2,706 ⁱ
9) Electricity used for transmission and distribution						3,870 ^k
Total input energy, GJ						36,731

Note: CO₂ = carbon dioxide; NOx = mononitrogen oxides, including nitric oxide and nitrogen dioxide; GJ = gigajoule. Gigajoules of energy consumed (GJ) values are derived by multiplying either input values of short tons CO₂, gallons diesel fuel consumed, metric tons of NOx released, or input quantities of materials and supplies by factors as provided in the supporting information on the Web. All values are approximate; precision to level of all digits shown is not implied.²

^aExcept as otherwise noted, short tons CO₂ emitted from an activity or gallons of diesel fuel consumed are as reported in the greenhouse emissions section of the New York Department of Environmental Conservation's *Supplemental Generic Environmental Impact Statement* (SGEIS) (NYDEC 2011).

^bRepresents initial quantity used. Oil-based drilling mud is reused and eventually recycled, at which time most of the original oil is recovered (Bolander 2011). GJ value used represents assumed loss of initial quantity of approximately 10% per well.

^cRepresents fuels used for a 15-stage hydrofracturing operation, with 10 to 12 pumping units operating in series, which is typical for Marcellus operations (Bolander 2011). This value is greater than the 29,000 gallons (gal) reported for hydrofracturing in the NYDEC's SGEIS referenced above.

^dNOx emission values (metric tons) in this column based on presentation of preliminary findings of a study. (Robinson 2011). This study used estimates of energy consumed to derive NOx emission estimates, but the energy values have not been published to date. We have back-calculated energy quantities based on the NOx estimates, using the estimated factor for diesel engines. This factor equates diesel NOx emissions with power production per unit of time, which is directly proportional to energy consumption.

^eAssumes depth of 7,000 to 10,000 feet (ft) (Jiang et al. 2011), with 50 ft of 24-inch (in) pipe weighing 160 pounds per foot (lb/ft) for a total of 3,600 kilograms (kg), 450 ft of 20-in pipe weighing 120 lb/ft for a total of 24,500 kg, 500 ft of 10-in pipe weighing 50 lb/ft for a total weight of 11,400 kg, and 6,000 to 9,000 ft of 5.5-in pipe weighing 20 lb/ft for a total weight of 54,480 to 81,720 kg for a grand total of approximately 94,000 to 121,000 kg of steel pipe. Sizes of pipe are based on those reported as typical for a Marcellus horizontal well (Range Resources 2010; Pennsylvania State University 2012).

^fAssumes typical mass of cement used for casing is 170 metric tons (Paterson 2012b).

^gTen percent of total energy used for well drilling and completion, as referenced in table S1 in the supporting information available on the Journal's Web site.

^hThis value is uncertain and depends, in large part, on how many miles of pipeline will be constructed per well, which, in turn, depends on a variety of factors. Little data are available on likely pipeline construction scenarios; further, pipelines can be expected to have long lifetimes and offer the potential of serving many wells. Therefore, it is unclear how much of the embodied energy should be assigned to a new well. Calculations assume that between one and three miles (mi) of gathering lines are installed per well (high-end value of reported likely range) (Skone 2012), that these lines are constructed of 6-in diameter steel that weighs 20 lb/ft and costs \$25/ft, and that the total cost of installation of such lines is \$100,000/mi (high end of reported range) (ICF International 2009).

ⁱThis value is uncertain and depends, in large part, on how much fluid is used in a typical hydraulic fracturing operation. Average values for these parameters were 7.8 million gal of water, 440,700 gal of sand, and 11,521 gal of chemicals used in the hydrofracturing process per well (NYDEC 2011). Sand and chemical quantities are based on proportions provided by industry (Range Resources 2010). High- and low-range estimates were developed based on varying assumptions of depth of a typical well and high- and low-end ranges of estimated quantity of water used per well.

^jThis value is uncertain and depends, in large part, on how much wastewater will require treatment. It has been reported that industry is increasingly using deep-well injection in Ohio as a disposal option (Paterson 2012a). However, analysis of data available from the PA DEP indicates that, in the last half of 2011, most "frac fluid" was disposed of via a "brine or industrial waste treatment plant" or through "reuse other than road spreading" (PA DEP 2012). Analysis of this data set indicates that the 90th percentile of quantity disposed per well was approximately 525,000 gal, median value was approximately 85,700 gal, and 10th percentile quantity was 2,300 gal. Calculations used these values as upper and lower bounds and also assumed that the lower bound value was disposed by the least energy-intensive method (deep-well injection in Ohio) and that the associated life cycle energy consumption for this method is approximately 105,000 British thermal units (BTUs) per barrel, as reported in a recent study (Harto 2011). Calculations used the 90th percentile quantity as a high-end value, as noted above, and assumed energy consumption of approximately 410,000 BTUs, which appears to represent the high end of likely energy consumption according to the same study.

^kMost of the energy used for compression and processing of natural gas is natural gas itself. As discussed below, this portion has been subtracted from the output quantity. However, some electricity is used in natural gas pipeline operations, and because this represents energy exogenous to the energy in the produced gas, it represents an input. In 2009, this quantity was estimated to be 2,711.1 kilowatt-hours in the United States, which represents a total heat content energy input of 2.80×10^{13} BTUs (Davis et al. 2011). Because total U.S. natural gas production in that year was 22,839,158 million cubic feet, or 2.35×10^{16} BTUs (EIA 2011a), the electricity used by pipelines represents approximately 0.12% of the energy in the natural gas at the wellhead. Consequently, 0.12% of the natural gas produced by a typical Marcellus well has been added as an input.

The mean cumulative production total for all 343 wells at the end of the latest period of the data (approximately 2.3 years) is 1.57 ± 0.11 Bcf (95% confidence interval). The mean of the randomly selected 20 wells at the end of the latest period is 1.53 ± 0.58 Bcf, and the mean modeled cumulative production, or

EUR, of these 20 wells at 30 years is 3.5 ± 1.1 Bcf. This mean EUR is a little more than twice the 2.3-year production total. As shown in figures 2 and 3, there is much variation among the wells and therefore much uncertainty in the projections. If, however, the production levels of all 343 wells scale up in a

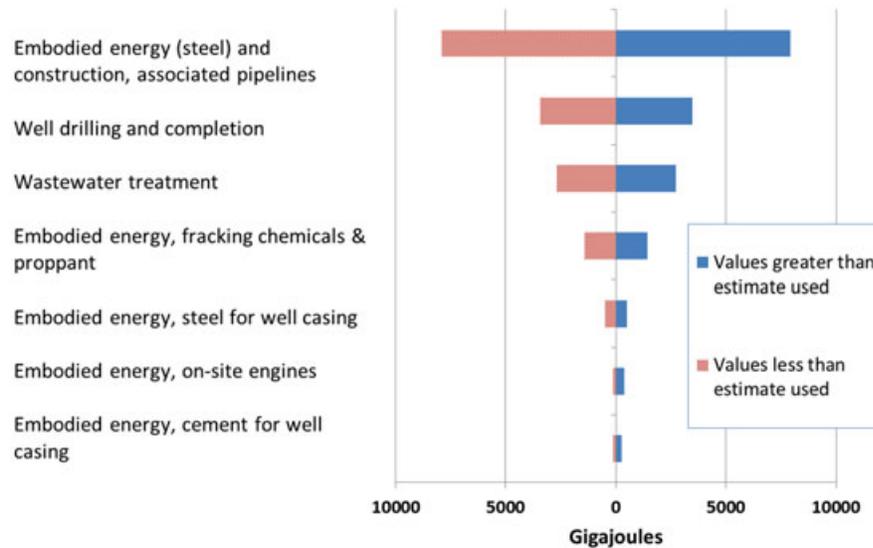


Figure 1 Chief input energy uncertainties and ranges of values: extents of ranges of estimated values above and below mean value for parameter shown.

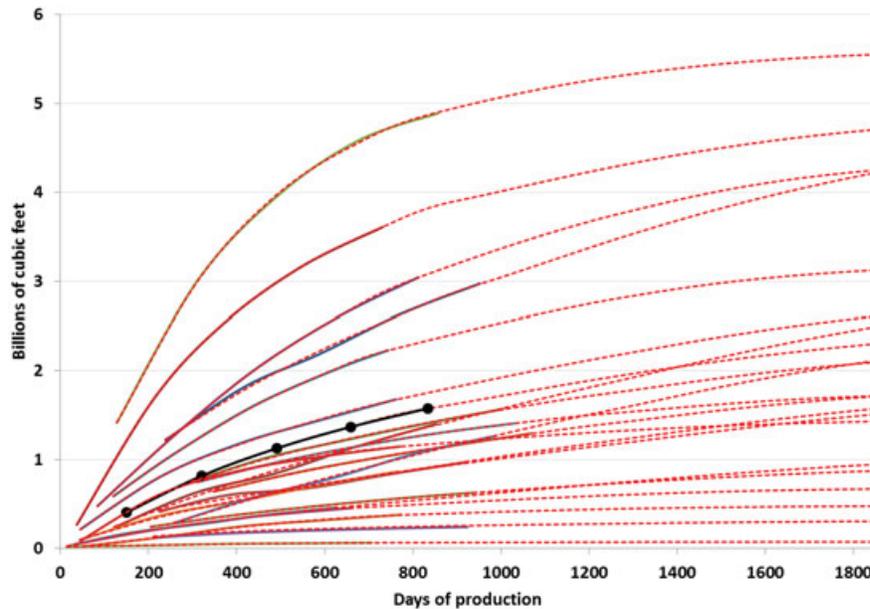


Figure 2 Cumulative production versus days (five years): individual randomly selected Pennsylvania Marcellus wells and average of all 343 wells in database. Solid lines represent smoothed curve of actual production data; dotted lines represent extensions to 1,825 days (five years) based on best-fitting curve of form described in text; solid line with dark circles represents smoothed curve of average of actual production data of all wells in sample.

manner similar to that which is projected for the 20 randomly selected wells, the distribution of the EURs for all wells would be as shown in figure 4.

Even when a curve appears to fit its data well, there is always considerable uncertainty with projections of nonlinear trends, such as production from shale gas wells, especially when the curve projects far beyond the range of the available data. Despite an initial good fit of an equation, the behavior may deviate over time from early projections for a variety of reasons. Further, it is possible, and perhaps likely, that the wells reporting production

so far are those wells that are expected to be among the best-performing wells, and that other wells drilled in the Marcellus formation have not, so far, entered production because their EUR, in the estimation of their owners, is likely to be lower.

Whatever the EUR, it must be adjusted to account for the natural gas consumed during the compression and processing that is necessary to get the gas to consumers. Most of the energy used for compression and processing is natural gas; however, some electricity is used for pipeline compressors (Davis et al. 2011). The energy value of this electricity has been included as

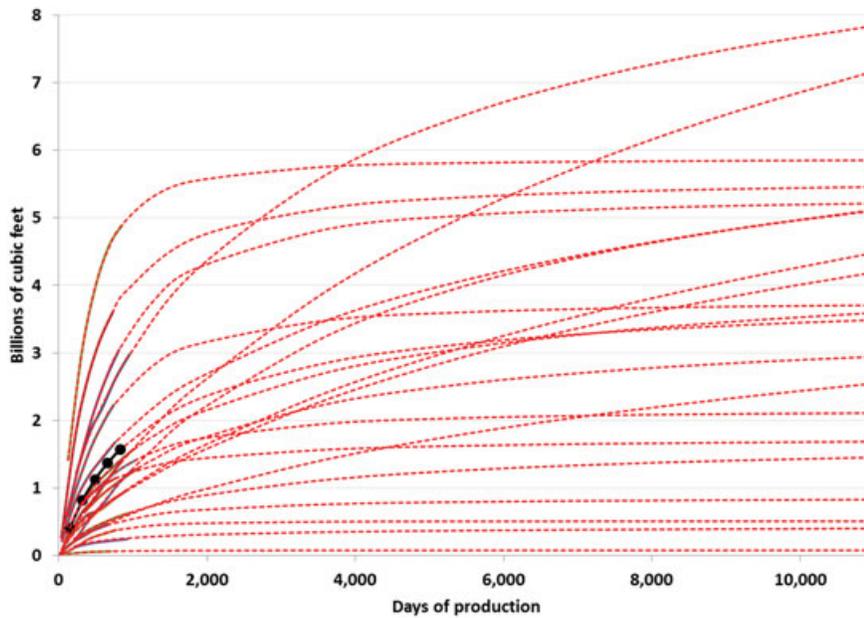


Figure 3 Cumulative production versus days (30 years): individual randomly selected Pennsylvania Marcellus wells and average of all 343 wells in database. Solid lines represent smoothed curve of actual production data; dotted lines represent extensions to 10,950 days (30 years) based on best-fitting curve of form described in text for each selected well; solid line with dark circles represents smoothed curve of average of actual production data of all wells in sample.

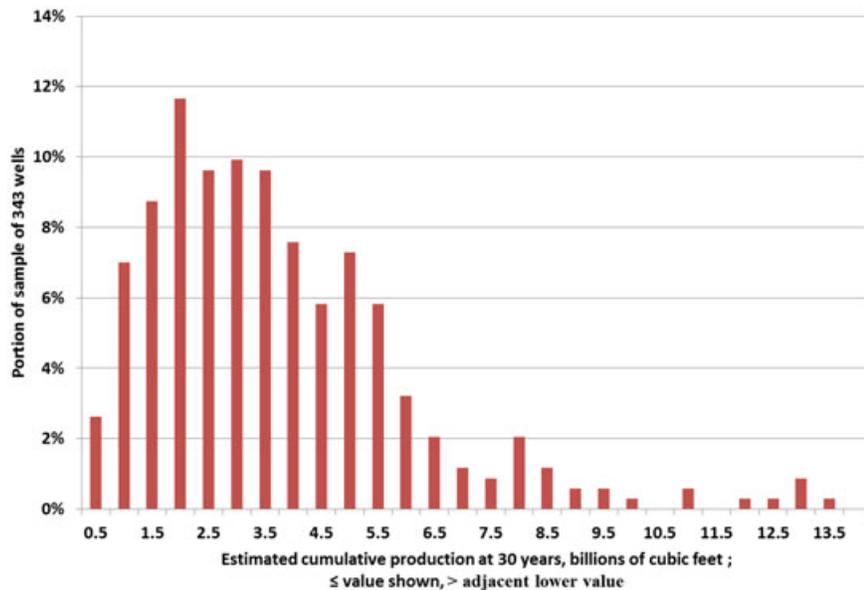


Figure 4 Approximate projected estimated ultimate recovery (EUR); distribution of Marcellus horizontal shale gas wells: EUR is assumed equal to projected 30-year cumulative production, based on projection of each of 343 wells with data for the entire approximately three-year reporting period, projected using equation of best-fitting curve of average production of all wells in database. Bars in chart represent portions of wells with projected production less than or equal to corresponding value shown on x-axis below bar and greater than the x-axis value of the bar to the left.

an input and is discussed in footnote k of table 2. The energy value of this electricity is included because, if it were not used to compress natural gas, it would be used for something else. However, the natural gas portion of the energy used for compression and processing is not an input in the same sense as energy used to extract the gas because it represents a portion of the gas that

has been newly produced and would not be used if the gas were not produced; instead, it would remain in the ground. The U.S. Energy Information Administration (EIA) reports that approximately 8.2 percent of the wellhead quantities of natural gas are consumed for compression and processing, which they term “lease fuel,” “plant fuel,” and “pipeline fuel” (EIA 2011a).

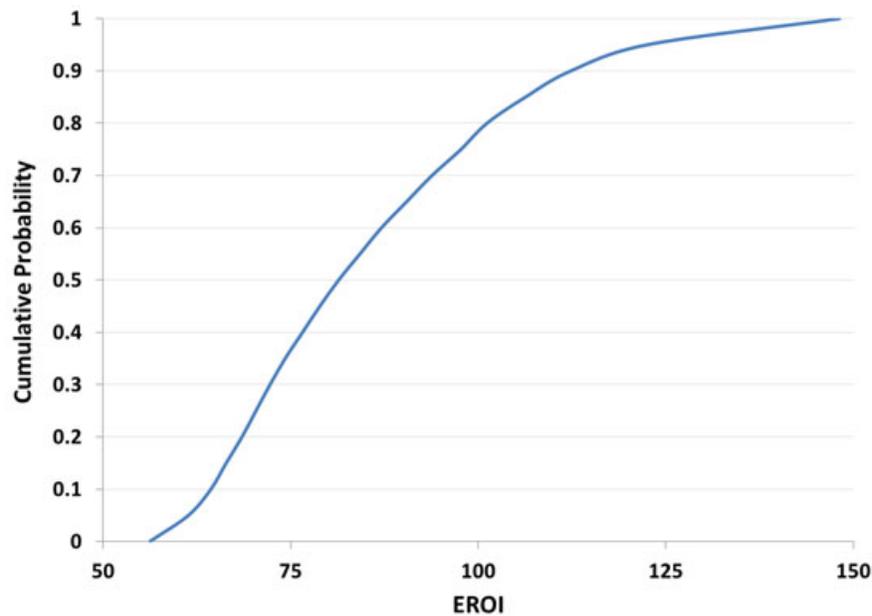


Figure 5 Monte Carlo simulation, with assumed estimated ultimate recovery (EUR) of 3.0 billion cubic feet (Bcf); values from literature and other sources as cited in text for each input parameter considered were treated as noncorrelated random independent variables; output was considered to be 3.0 Bcf minus 8.2% used for processing and compression.

In light of the range of values reported and the estimates based on PA DEP production reports, an EUR in the approximate range of 3 Bcf appears to be a reasonable estimate of a typical well's production. This quantity translates to approximately 3.25×10^6 GJ. Subtracting 8.2% of this quantity to account for compression and processing translates to an output energy of approximately 2.98×10^6 GJ. Comparing this output energy estimate to the mean estimate of input energy of 36.7×10^3 megajoules results in an EROI of 81:1.

Clearly, there is considerable uncertainty in this ratio. In an effort to place bounds on this uncertainty, two Monte Carlo simulations (MCSs) were performed. In the first simulation, an EUR of 3.0 Bcf was assumed. Energy input parameters were treated as equally likely discrete random variables representing the high, mean, or low value where two or more estimates for that parameter were available in the literature, or one value where only one report was available. No correlation was assumed between the parameters. The mean EROI based on 10,000 randomized iterations of the EROI calculation, as per equation (2), produced a mean of 85:1, with a 10th percentile of 64:1 and a 90th percentile of 112:1 (see figure 5).

The EUR is uncertain, and a variety of estimates are reported. A second simulation was performed using five EUR values, as reported in the literature, as discrete random variables with equal probability: 1.158, 2.7, 3.75, 4 (mean of estimated 3 to 5), and 5.375 (mean of reported range of 3.75 to 7) Bcf. Energy input parameters were treated as in the first simulation. This simulation produced a mean EROI value of 93:1, with a 10th percentile of 34:1 and 90th percentile of 148:1. The highest EUR, 5.375 Bcf, and the lowest, 1.158 Bcf, in this range appear

unlikely based on initial production reports and our projections of these, and a range this wide therefore also appears unlikely.

If the EROI is calculated in an alternate way, by including the compression and processing quantity in the denominator, which corresponds to a NER as described above, the EROI would fall in the range of 8.0:1 to 11.8:1. This is because, with this calculation approach, the denominator value, and hence the EROI ratio itself, is dominated by the 8.2% of the produced quantity used for compression and processing.

Discussion

The range of EUR values in this study is not dissimilar to the 50:1 to 85:1 range that is reported for coal, and higher than the 20:1 to 40:1 range that has been estimated for natural gas in general (Murphy 2011). The range is higher than some estimated EROI values for wind (20:1), new nuclear (15:1), and photovoltaic electricity (10:1) and much higher than two other new sources of FF, tar sands, and oil shale, which a 2011 study asserts are in the range of 5:1 to 3:1 (Murphy 2011).

Some of the EROI values above represent energy in the raw fuel as delivered to the user, and some represent energy that is supplied in a directly usable form (e.g., electricity). For a comprehensive comparison, conversion efficiencies must also be considered. For example, whereas coal or natural gas may be used as a fuel to generate electricity, the efficiency of this generation can vary considerably, from less than 30% for some older coal-burning power plants to greater than 50% for modern, combined cycle gas-burning plants to greater than 75% for combined heat and power facilities.

The NER type of calculation, which includes self-use of a produced fuel in the denominator, results in a much lower estimated EROI for natural gas in general. Use of this method may account for differences between other energy source EROI calculations as well. Because of the variety of EROI methods, it is important, as noted by Murphy and colleagues (2011), that inclusions and boundaries be clearly noted.

A focus on the energy-consuming steps only is limited and does not include important or potentially important aspects of the shale gas production process. Potentially important aspects include the following:

1. Energy not directly used in the shale gas extraction process or embodied in machinery and materials directly used in this process (e.g., energy inputs associated with exploration, geologic characterization, site engineering activities, and land acquisition)
2. Energy used to remediate any social, environmental, or infrastructure problems caused by or arising from the shale gas extraction process
3. Energy used by workers employed in the shale gas industry
4. Energy costs and other costs associated with impacts to resources, such as depletion of water supply, fragmentation of forests and related loss of habitat, and contamination of the local or regional atmosphere with air pollutants, including GHGs

Summary and Conclusion

An analysis of the EROI of natural gas obtained from horizontal, hydraulically fractured wells in the Marcellus Shale was performed using NEER methodology. Used in this analysis were results of studies that estimated emissions of carbon dioxide and nitrogen oxides from gas extraction activities (NY-DEC 2011; Robinson 2011). Also used were data on fuel used by these activities. These quantities were converted to energy values using readily available factors. Estimates of quantities of materials used and the associated embodied energy, as well as other energy-using steps, were also developed from available data. Total input energy was compared with the energy expected to be made available to end users of the natural gas produced from a typical Marcellus well. Though there is considerable uncertainty regarding input energy values, approximate agreement of input values for the well drilling and completion steps, as determined from the two referenced studies and a reality check and update by a gas extraction company active in the Marcellus region (Bolander 2011), suggest that the values used are at least approximately accurate. Other input values, including quantities of energy used to treat wastewater, embodied energy of hydraulic fracturing chemicals, and energy consumed for pipeline construction, are less certain. The mean total input energy was estimated at approximately 36.7×10^3 GJ, with a range of 20.3×10^3 to 53.3×10^3 GJ.

Output energy, the EUR, of a typical well is also uncertain. An approximate mid-point of the range that has been reported is 3 Bcf. Subtracting 8.2% of this value to account for the portion

of the produced gas that is consumed in the processing and distribution system results in an output energy of 2.98×10^6 GJ.

An MCS was performed using 3.0 Bcf as the EUR and treating energy input parameters as noncorrelated and equally likely discrete random variables representing the high, mean, or low value where two or more estimates for that parameter were available in the literature, or one value where only one report was available. The simulated mean was 85:1, with a 10th percentile of 64:1 and a 90th percentile of 112:1. The EROI is largely proportional to the EUR, the most sensitive parameter. A second simulation was performed using five EUR values, as reported in the literature, as discrete random variables with equal probability. This simulation produced a mean EROI value of 93:1, with a 10th percentile of 34:1 and 90th percentile of 148:1. The highest EUR, 5.375 Bcf, and the lowest, 1.158 Bcf, in this range appear unlikely based on our review and modeling of initial production data, so a range this wide, though possible, appears unlikely.

Notes

1. One cubic foot (ft^3) \approx 0.0283 cubic meters (m^3 , SI).
2. Conversions for units in table 2 and corresponding table notes: One short ton = 2,000 pounds (lb) \approx 907 kilograms (kg, SI) = .907 metric tons.
One kilogram (kg, SI) \approx 2.204 pounds (lb).
One gallon (gal) \approx 3.79 liters (L).
One gigajoule (GJ) = 10^9 joules (J, SI) \approx 2.39×10^5 kilocalories (kcal) \approx 9.48×10^5 British Thermal Units (BTUs).
One kilowatt-hour (kWh) \approx 3.6×10^6 joules (J, SI) \approx 3.412×10^3 British Thermal Units (BTUs).
One inch (in) = 2.54 centimeters (cm).
One foot (ft) \approx 0.3048 meters (m, SI).
One mile (mi) \approx 1.61 kilometers (km, SI).
One cubic foot (ft^3) \approx 0.0283 cubic meters (m^3 , SI).

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Supporting Information

Additional Supporting Information may be found in the online version of this article at the publisher's web site:

Supporting Information S1: This supporting information consists of one table (table S1) containing the conversion factors used in performing various calculations related to extracting natural gas from Marcellus shale.