NETL Life Cycle Inventory Data
Process Documentation File

Process Name:	Natural Gas Well Completion
Reference Flow:	1 kg of produced natural gas
Brief Description:	Air emissions from the completion of conventional and unconventional natural gas wells.

Section I: Meta Data

Geographical Coverage: United States **Region:** Multiple U.S. Regions

Year Data Best Represents: 2010

Process Type: Extraction Process (EP)

Process Scope: Cradle-to-Gate Process (CG)

Allocation Applied: No

Completeness: All Relevant Flows Captured

Flows Aggregated in Data Set:

☑ Process ☐ Energy Use ☐ Energy P&D ☐ Material P&D

Relevant Output Flows Included in Data Set:

Releases to Air:	☐ Greenhouse Gases	☐ Criteria Air	☑ Other
Releases to Water:	☐ Inorganic	☐ Organic Emissions	☐ Other
Water Usage:	☐ Water Consumption	☐ Water Demand (throughput)	
Releases to Soil:	☐ Inorganic Releases	☐ Organic Releases	☐ Other

Adjustable Process Parameters:

IP	*[mcf/day] Initial production rate of natural gas from hydraulically fractured wells (tight and shale gas)*
Tflowback	*[days] Flowback period*
NGother	*[mcf/episode] Potential completion emissions from conventional and CBM wells*

EURbcf	*[Bcf] Estimated ultimate recovery of natural gas from a single well over its entire life (billion cubic feet)*

Tracked Input Flows:

Tracked Output Flows:

Natural Gas Extraction, Completion	*Reference flow*
Natural gas [intermediate product]	*[Intermediate Product] Natural gas to venting and flaring*

Section II: Process Description

Associated Documentation

This unit process is composed of this document and the data sheet (DS) *DS_Stage1_O_NG_Extraction_Completion_2014.01.xlsx*, which provides additional details regarding relevant calculations, data quality, and references.

Goal and Scope

This unit process provides a summary of relevant input and output flows associated with the completion of natural gas wells. Well completions are the activities following well drilling and preceding production. For hydraulically fractured wells, completion includes the flowback water that contains natural gas. Potential emissions are calculated in this unit process; potential emissions are the amount of gas prior to flaring or other environmental controls. The reference flow of this unit process is: 1 kg of produced natural gas.

Boundary and Description

Low pressure wells include conventional wells (onshore and offshore) and coal bed methane (CBM) wells. In this context, “low pressure” is a relative term used to distinguish this group of wells from shale and tight gas wells that have high initial pressures. These wells do not have large potential emissions during well completion. The volume natural gas that escapes from these wells during completion operations is based on factors that the Environmental Protection Agency (EPA) developed from Gas Research Institute (GRI) research conducted in 1996; conventional wells and CBM wells produce 37.0 and 49.6 thousand cubic feet (Mcf) of potential natural gas emissions, respectively, per completion episode. (EPA, 2010)

High pressure wells include shale gas and tight gas wells, which are developed by hydraulic fracturing (hydrofracking) of a reservoir. Hydrofracking stimulates shale gas and tight gas reservoirs, liberating natural gas (and other hydrocarbons) from otherwise trapped pockets (or microscopic pores). Due to the high reservoir pressures created by hydrofracking, shale gas and tight gas wells have high initial production rates that quickly decline. If production infrastructure is not immediately installed, these wells can produce high potential emissions of methane and other hydrocarbons. For shale gas and tight gas wells, this unit process uses initial production rates factored by the flowback period as a proxy for the volume of potential emissions generated by well completions.

Potential emissions represent the volume of natural gas that is available for flaring or other environmental controls. Potential emissions do not necessarily represent the volume of natural gas directly to the atmosphere. The output of this unit process is a flow of potential emissions that is sent to another unit process where conditions for venting and flaring are applied. The boundaries of this unit process do not include any direct emissions to the atmosphere.

The flowback period immediately follows the hydrofracking of wells. During flowback, most of the water that was used for hydrofracking flows out of the well, carrying natural gas and other well products. The flowback period lasts for a matter of days before gas recovery equipment is installed and the well is connected to downstream production infrastructure. The flows of water during flowback are not accounted for in this unit process, but are accounted for other unit processes in NETL's natural gas model. This unit process uses a value of 7 days for flowback period (EPA, 2011; EPA, ND; EPA, 2014).

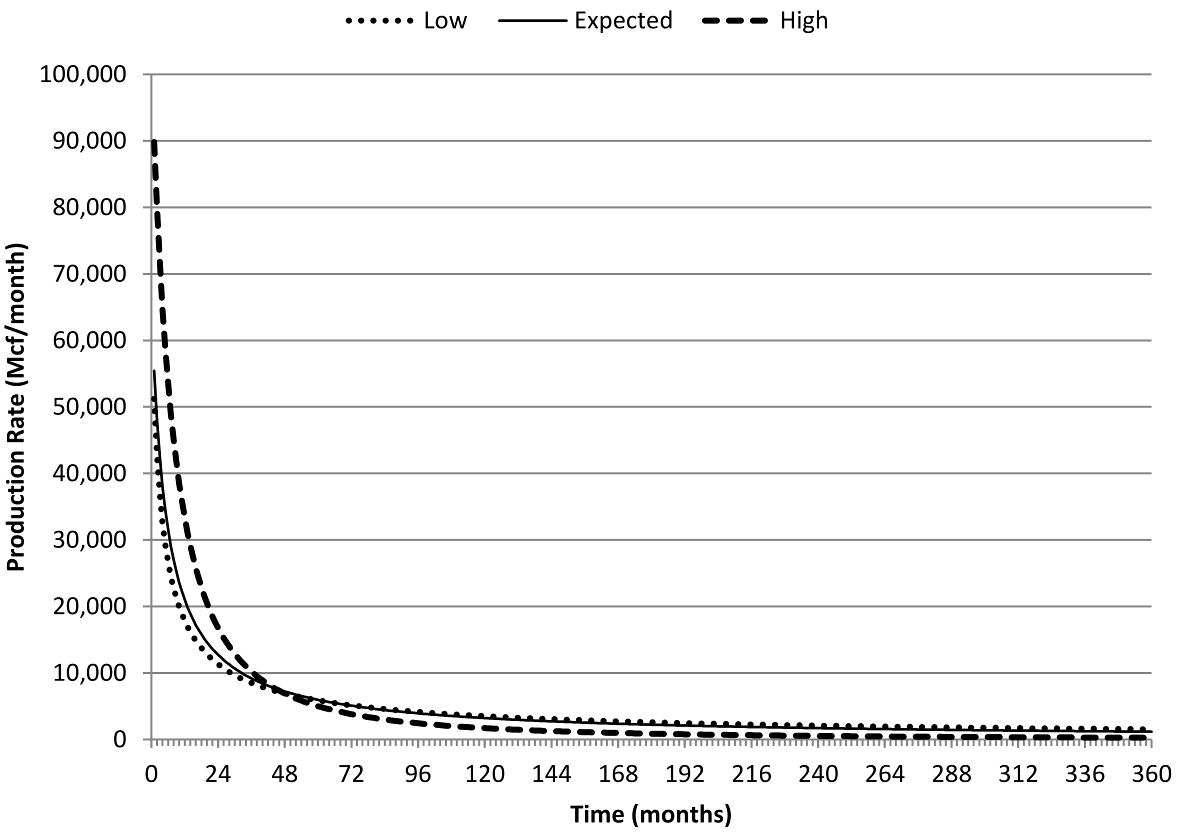
This unit process uses estimated ultimate recovery (EUR) as the denominator for apportioning the one-time potential emissions from well completion to a unit of natural gas produced. This is necessary because, unlike other types of emissions that occur continuously over a well's life, completion emissions are a one-time impulse of emissions that, from a life cycle perspective, must be levelized over a well's operating life. Empirical studies show that the production rates of these wells decline at hyperbolic rates. EURs for various shale and tight gas plays are available in EIA analyses of unconventional production (EIA, 2011a; EIA, 2013). The EUR for conventional onshore natural gas was calculated from EIA's performance profile for large energy producers (EIA, 2011b); for this particular calculation, 2008 production data was used to represent onshore conventional wells because it was the last data year that did not include unconventional wells (shale gas, tight gas, and CBM). The EUR for offshore conventional wells was calculated by EIA production statistics for federal offshore wells in the Gulf of Mexico (EIA, 2011c). The EURs for CBM wells were calculated using production data for the four major CBM regions in the U.S. (Appalachia, Black Warrior, Powder River, and San Juan); these EURs are variable among basins (EIA, 2010). **Table 1** shows the EURs for conventional and CBM wells.

Table 1: EURs for Conventional and CBM Wells

Extraction Technology	Low	Expected	High	Units
Onshore Conventional	1.2	1.5	1.8	Bcf
Offshore Conventional	15.4	19.3	23.1	Bcf
CBM, Appalachian Basin	0.08	0.12	0.18	Bcf
CBM, Black Warrior Basin	0.08	0.21	0.21	Bcf
CBM, Central U.S.	0.06	0.17	0.22	Bcf
CBM, Rocky Mountains	0.06	0.23	1.51	Bcf

As mentioned above, this unit process uses initial production rates as a factor in estimating the potential emissions from shale and tight gas well completions. Data on initial production rates are available for the Hayneville-Bossier Shale and Barnett Shale plays (EIA, 2013). The initial production rates for other shale and tight gas plays were calculated using decline curve analysis (DCA). DCA uses the initial production rates, decline rates, and assumptions about long term performance to estimate the total volume of natural gas ultimately recovered from a well. Empirical studies have shown that shale and tight gas wells follow a hyperbolically declining production curve, as illustrated in **Figure 1**.

Figure 1: Example of Decline Curves for Marcellus Shale Gas Production



The curves shown in **Figure 1** are based on the observed performance characteristics of shale gas wells in the Marcellus Play. The three scenarios in **Figure 1** represent low, expected, and high values for initial production rate. In this case, all scenarios have the same EUR (1.6 Bcf), which is represented by the area under each curve. However, each curve has a unique initial production rate and a unique initial decline rate.

The production rate for a given point in a well's life is a function of the initial production rate (q_i), initial decline rate (a_i), decline exponent (b), and elapsed well operating time (Δt) as expressed by **Equation 1**. For this unit process, initial production rate (q_i) is the average daily production during the first month of well operation. The initial decline rate is the percent change in production between the first and second month of operation.

$$q = \frac{q_i}{(1 + b\, a_i\, \Delta t)^{\left(\frac{1}{b}\right)}} \qquad \text{(Equation 1)}$$

The value of the decline exponent affects the shape of the decline curve. If the decline exponent is 0, then the production curve declines at a constant rate. If the decline exponent is between 0 and 1, then the curve follows hyperbolic decline; the decline rate is sharpest during initial conditions. If the decline exponent equals 1, then the decline rate is harmonic – a special case of hyperbolic decline in which the decline rate steeply declines, but the cumulative production rate is constant. Decline exponents greater than 1 imply infinite EURs and do not have a physical explanation. (Fekete Associates, 2014) This unit process uses decline curve exponents greater than 1, keeping in mind that decline curve analysis is an empirical calculation (i.e., the objective is to fit curves to production rates that are demonstrated by actual wells).

Instead of using DCA to calculate EUR, this unit process uses DCA to back calculate initial production rates from play-specific EURs. Play-specific EURs are available in the Energy Information Administration's (EIA) documentation of the National Energy Model (NEM) and EIA's analysis of shale gas growth (EIA, 2011a; EIA, 2013). To back-calculate initial production rate from EUR, well life and decline curve parameters must be specified. This analysis uses a well life of 30 years for shale gas and tight gas wells. The decline curve parameters (decline rate of initial production and the decline exponent) for nine shale gas plays in the U.S. were averaged to arrive at low, expected, and high parameters for typical decline curves (EIA, 2013). It is assumed that these decline curve parameters can be used to represent shale gas and tight gas wells.

The factors for completion emissions from unconventional wells are based on decline curves. These decline curves are based on projections of future production. Future production is uncertain, and thus the factors for completion emissions are also uncertain. To account for this uncertainty, the expected values for initial decline rates and the decline exponent are accompanied by low and high values. The expected value for initial decline rate is 18.2% per month; this parameter is bounded by low and high values of 12.8% and 28.2% per month. The expected value for the decline exponent is 1.06; this parameter is bounded by low and high values of 0.55 and 1.31. These uncertainty bounds are based on the lowest and highest values exhibited by the middle 70% of shale gas plays (EIA, 2013) and are assumed to be representative of the low and high decline curve parameters for all shale and tight gas wells. Initial decline rates and decline exponents have an inverse relationship with EUR, so the low value for each parameter is paired with the high scenarios for initial production rate, and the high value for each parameter is paired with the low scenarios for initial production rate.

Table 2 and **Table 3** show the decline curve parameters used to calculate the initial production rates for shale gas and tight gas wells, respectively. Unlike a typical decline curve analysis, in which initial production characteristics are used to calculate EUR, this unit process uses EURs reported by EIA for specific shale gas plays, and solves for the initial production rate. (The initial production rate, as discussed above, is used to calculate the potential emissions from shale and tight gas well completions.)

Table 2: Shale Gas Decline Curve Parameters

Region	Play	Uncertainty Category	Initial Decline Rate, Di (% decline per month)	Hyper-bolic Exponent, b	EUR	Initial Production, Qi (mcf/d)
West Coast (Columbia Play)	Columbia	Low	28.2%	1.305	1.40	1,913
		Expected	18.4%	1.059	1.40	1,926
		High	12.8%	0.548	1.40	2,986
West Texas/Permian Basin	Barnett-Woodford	Low	28.2%	1.305	1.51	2,067
		Expected	18.4%	1.059	1.51	2,081
		High	12.8%	0.548	1.51	3,227
Illinois/Michigan Basin	New Albany	Low	28.2%	1.305	1.72	2,351
		Expected	18.4%	1.059	1.72	2,368
		High	12.8%	0.548	1.72	3,670
North-Central	Williston, Gammon	Low	28.2%	1.305	0.44	601
		Expected	18.4%	1.059	0.44	605
		High	12.8%	0.548	0.44	938
Rocky Mountains	Mancos	Low	28.2%	1.305	0.89	1,213
		Expected	18.4%	1.059	0.89	1,222
		High	12.8%	0.548	0.89	1,894
Central	Fayetteville-Central	Low	28.2%	1.305	1.44	1,973
		Expected	18.4%	1.059	1.44	1,987
		High	12.8%	0.548	1.44	3,080
Appalachian Basin	Marcellus-Interior	Low	28.2%	1.305	1.59	2,171
		Expected	18.4%	1.059	1.59	2,186
		High	12.8%	0.548	1.59	3,389

Table 3: Tight Gas Decline Curve Parameters

Region	Play	Uncertainty Category	Initial Decline Rate, Di (% decline per month)	Hyper-bolic Exponent, b	EUR	Initial Production, Qi (mcf/d)
North-Central	Baken-Central	Low	28.2%	1.305	0.11	76.5
		Expected	18.4%	1.059	0.11	77.0
		High	12.8%	0.548	0.11	119.5
Illinois/Michigan Basin	Berea Sand	Low	28.2%	1.305	0.14	97.5
		Expected	18.4%	1.059	0.14	98.5
		High	12.8%	0.548	0.14	152.5
TX-LA-MS Salt Basin	Cotton Valley	Low	28.2%	1.305	1.47	1,005.5
		Expected	18.4%	1.059	1.47	1,012.5
		High	12.8%	0.548	1.47	1,569.5
Appalachian Basin	Clinton-Medina	Low	28.2%	1.305	0.06	41.0
		Expected	18.4%	1.059	0.06	41.5
		High	12.8%	0.548	0.06	64.0
Central	Granite Wash	Low	28.2%	1.305	0.95	647.5
		Expected	18.4%	1.059	0.95	652.0
		High	12.8%	0.548	0.95	1,011.0
Gulf Coast	Austin Chalk-Giddings	Low	28.2%	1.305	0.05	33.0
		Expected	18.4%	1.059	0.05	33.0
		High	12.8%	0.548	0.05	51.0
Rocky Mountains	Muddy	Low	28.2%	1.305	0.18	124.5
		Expected	18.4%	1.059	0.18	125.0
		High	12.8%	0.548	0.18	194.0

The initial production rates in **Table 3** are adjusted to account for the linear ramping in initial production rate; initial flowback is entirely water, the composition of natural gas in flowback increases linearly, and the final composition of flowback is entirely natural gas. To account for this flowback pattern, the initial production rates for tight gas are divided by 2. This adjustment is not applied to the production rates in **Table 2** because immediate gas breakthrough has been observed for shale gas wells (Abbasi et al., 2014).

Figure 2 illustrates the boundaries of this unit process. This unit process does not receive any inputs from upstream unit processes -- the only input is natural received directly from nature. The outputs include the reference flow of 1 kg of produced natural gas and an intermediate flow of potential natural gas emissions which are sent to a downstream unit process that accounts for venting and flaring. **Table 4** shows the values for unit process inputs and outputs per 1 kg of produced natural gas.

Figure 2: Unit Process Scope and Boundary

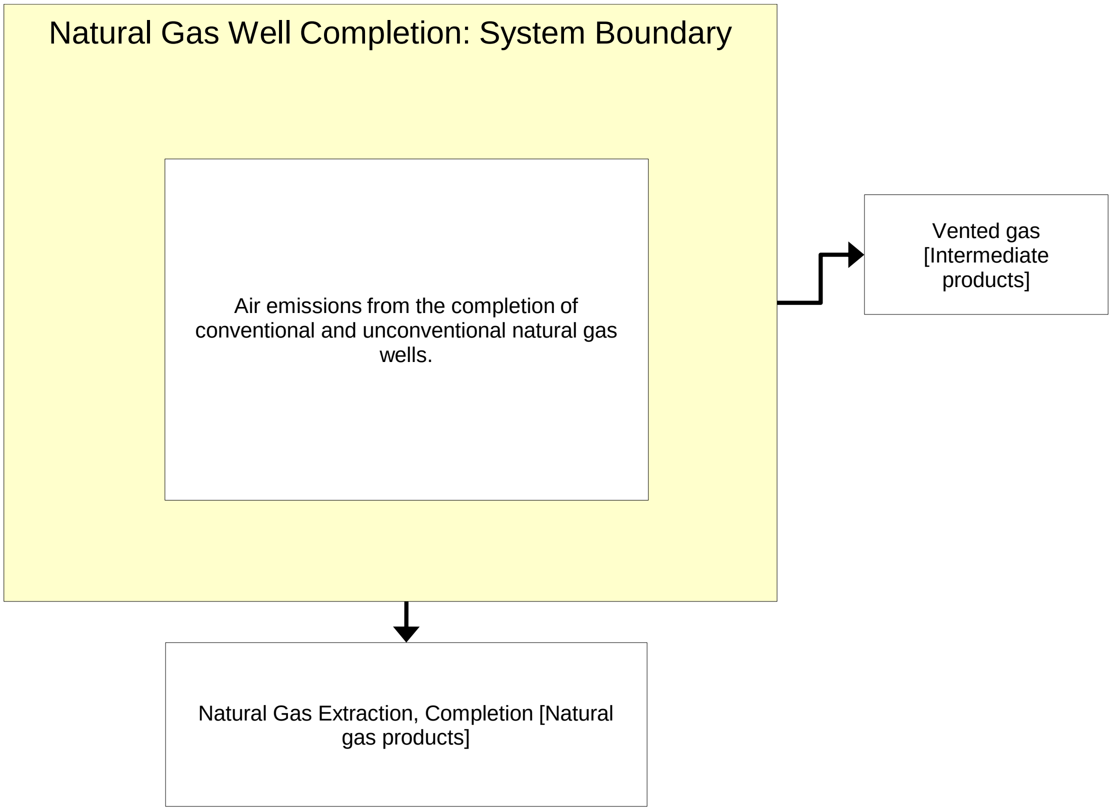


Table 4: Unit Process Input and Output Flows

Flow Name	Value	Units (Per Reference Flow)
Inputs		
Natural gas USA [Natural gas (resource)]	0.00963	kg
Outputs		
produced natural gas	**1.00**	**kg**
Natural gas [intermediate product]	**0.00963**	**kg**

* **Bold face** clarifies that the value shown *does not* include upstream environmental flows.

Embedded Unit Processes

None.

References

Abbasi et al. (2014). A comparative study of flowback rate and pressure transient behavior in multifractured horizontal wells completed in tight gas and oil reservoirs. Journal of Natural Gas Science and Engineering. Accessed on April 13, 1015 at http://ac.els-cdn.com/S187551001400002X/1-s2.0-S187551001400002X-main.pdf?_tid=5fdca9c6-e1e0-11e4-b08e-00000aacb35d&acdnat=1428931632_262b6ca8fa38177859f80a44f8b97799.

EPA (2010). Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry: Background Technical Support Document. Environmental Protection Agency. Accessed on September 2, 2014 at http://www.epa.gov/ghgreporting/documents/pdf/2010/Subpart-W_TSD.pdf

EPA (2011). Reduced Emissions Completions fro Hydraulically Fractured Natural Gas Wells. United States Environmental Protection Agency. Washington, DC. Accessed on August 27, 2014 at http://www.epa.gov/gasstar/documents/reduced_emissions_completions.pdf.

EPA (2014). Oil and Natural Gas Sector Hydraulically Fractured Oil Well Completions and Associated Gas during Ongoing Production. Accessed on August 27, 2014 at http://www.epa.gov/airquality/oilandgas/pdfs/20140415completions.pdf.

EPA (ND). Summary of Requirements for Processes and Equipment at Natural Gas Well Sites. Washington, DC. Accessed on August 27, 2014 at http://www.epa.gov/airquality/oilandgas/pdfs/20120417summarywellsites.pdf.

EIA (2010). Oil and Gas Lease Equipment and Operating Costs 1994 through 2009. Accessed on September 3, 2014 at http://www.eia.gov/pub/oil_gas/natural_gas/data_publications/cost_indices_equipment_production/current/coststudy.html

EIA (2011a). Review of Emerging Resources: U.S. Shale Gas and Shale Oil Plays. Energy Information Administration. Accessed on August 27, 2014 at http://www.eia.gov/analysis/studies/usshalegas/pdf/usshaleplays.pdf.

EIA (2011b). Performance Profiles of Major Energy Producers 2009. DOE/EIA-0206(09). Energy Information Administration. Accessed on September 3, 2014 at http://www.eia.gov/finance/performanceprofiles/pdf/020609.pdf.

EIA (2011c). Distribution and Production of Oil and Gas Wells by State. Energy Information Administration. Accessed on September 2, 2014 at http://www.eia.gov/pub/oil_gas/petrosystem/petrosysog.html

EIA (2013). NEMS Model Documentation 2013: Oil and Gas Supply Module. Energy Information Administration. Accessed on August 27, 2014 at http://www.eia.gov/forecasts/aeo/nems/documentation/ogsm/pdf/m063(2013).pdf.

Fekete Associates (2014). Traditional Decline Analysis Theory. Accessed on September 2, 2014 at http://www.fekete.com/SAN/WebHelp/FeketeHarmony/Harmony_WebHelp/Content/HTML_Files/Reference_Material/Analysis_Method_Theory/Traditional_Decline_Theory.htm

Section III: Document Control Information

Date Created: September 5, 2014

Point of Contact: Timothy Skone (NETL), Timothy.Skone@NETL.DOE.GOV

Revision History:

Original/no revisions

How to Cite This Document: This document should be cited as:

NETL (2014). NETL Life Cycle Inventory Data – Unit Process: Natural Gas Well Completion. U.S. Department of Energy, National Energy Technology Laboratory. Retrieved [date] from www.netl.doe.gov/LCA

Section IV: Disclaimer