NETL Life Cycle Inventory Data
Process Documentation File

Process Name:	Extraction of natural gas (NG) from coal bed methane (CBM)
Reference Flow:	1 kg of natural gas from coal bed methane
Brief Description:	Data for the extraction of natural gas from a coal bed methane formation.

Section I: Meta Data

Geographical Coverage:	US	**Region:**	N/A
Year Data Best Represents:	2010		
Process Type:	Extraction Process (EP)		
Process Scope:	Cradle-to-Gate (CG)		
Allocation Applied:	No		
Completeness:	Individual 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 Pollutants	☒ Other
Releases to Water:	☒ Inorganic Emissions	☒ Organic Emissions	☐ Other
Water Usage:	☒ Water Consumption	☒ Water Demand (throughput)	
Releases to Soil:	☐ Inorganic Releases	☐ Organic Releases	☐ Other

Adjustable Process Parameters:

Recip_userate	*Fraction of well life during which compression is necessary for gas recovery.*
NG_flared	*Natural gas that is flared per kg of natural gas produced*

Tracked Input Flows:

None.

Tracked Output Flows:

Natural Gas, CBM	*Natural gas extracted from coal bed methane*

Section II: Process Description

Associated Documentation

This unit process is composed of this document and the data sheet (DS) *DS_Stage1_O_CBM_NG_Extraction_2010.01.xls*, which provides additional details regarding relevant calculations, data quality, and references.

Goal and Scope

The scope of this unit process encompasses the material outputs for the extraction of natural gas from coal bed methane (CBM). The unit process is based on the reference flow of 1 kg of extracted natural gas. The relevant flows of this unit process are described below and shown in **Figure 1.**

The inputs to this unit process are natural gas, ground water, and surface water. These three inputs are natural resources and thus enter the boundary of this unit process with no upstream environmental burdens. The output of this unit process is dehydrated natural gas that is suitable for pipeline transport and subsequent processing steps such as sweetening or, in the case of imported natural gas, liquefaction. In addition to resource inputs and outputs that are used by downstream unit processes, this unit process also accounts for environmental emissions to air and water.

Boundary and Description

Natural gas can be recovered from coal seams through the use of horizontal drilling. The development of a well for coal bed methane requires horizontal drilling followed be a depressurization period during which naturally-occurring water is discharged from the coal seam. The production of natural gas from CBM wells accounts for approximately 7.5 percent of the U.S. natural gas production (EIA, 2009). There are viable coal bed methane deposits nationwide, but the majority of CBM production occurs in the Rocky Mountain region (ALL Consulting, 2004). The average daily output of the CBM wells of this analysis is 800 thousand cubic feet, which is representative of CBM wells in New Mexico and Colorado (ALL Consulting, 2004).

The key sub-systems for natural gas extraction include compression, dehydration, flaring, water use, and water quality. The data and assumptions for these sub-systems are described below.

Compression

Compressors are used at the natural gas wellhead to increase the gas pressure for pipeline distribution. The use of a compressor depends on the natural pressure at the wellhead, which varies from reservoir to reservoir and decreases with increasing well life.

The energy required for compressor operations is based on manufacturer data that compares power requirements to compression ratios (the ratio of outlet to inlet pressures). A two-stage compressor with an inlet pressure of 50 psig and an outlet pressure of 800 psig has a power requirement of 187 horsepower per MMCF of natural gas; a three-stage compressor with an inlet pressure of zero psig and an outlet pressure of 800 psig has a power requirement of 282 horsepower per MMCF of natural gas (GE Oil and Gas, 2005). Using a natural gas density of 0.042 lb/scf and converting to SI units gives a compression energy intensity of 1.76E-04 MWh per kg of natural gas and 2.65E-04 MWh per kg of natural gas, respectively. These energy intensities represent the required output of compressors per unit of natural gas that is compressed.

A reciprocating compressor uses pistons for gas compression. Reciprocating compressors used for industrial applications are driven by a crankshaft that can be powered by 2- or 4-stroke diesel engines. Reciprocating compressors are not as efficient as centrifugal compressors and are typically used for small scale extraction operations that do not justify the increased capital requirements of centrifugal compressors. The natural gas fuel requirements for a gas-powered, reciprocating compressor used for natural gas extraction are based on a compressor survey conducted for natural gas production facilities in Texas (Houston Advanced Research Center, 2006). The average energy intensity of a gas-powered turbine is 8.74 Btu/hp-hr (Houston Advanced Research Center, 2006). Using a natural gas heating value of 1,027 Btu/scf, a natural gas density of 0.042 lb/scf, and converting to SI units translates to 217 kg of natural gas per MWh of reciprocating compressor shaft energy output. This fuel factor represents the mass of natural gas that is combusted per compressor energy output. The air emissions from the combustion of natural gas in reciprocating compressors are based on EPA's AP-42 emission factors for fuel combustion in stationary equipment. These emission factors include greenhouse gases, criteria pollutants, and other air emissions specific to reciprocating compressors (EPA, 1995).

Flaring

Flaring is an intermittent operation, necessary in situations where a natural gas (or other hydrocarbons) stream cannot be safely or economically recovered. Flaring may occur when a well is being prepared for operations and the wellhead has not yet been fitted with a valve manifold, when it is not financially preferable to recover the associated natural gas from an oil well, or during emergency operations when the usual systems for gas recovery are not available.

The combustion products of flaring include carbon dioxide, methane, and nitrous oxide. Based on a 98 percent flaring efficiency, the flaring of 1 kg of natural gas results in air emissions of 3.0 kg, 1.8E-02 kg, and 3.4E-05 kg of carbon dioxide, methane, and nitrous oxide, respectively (API, 2009). This analysis assumes that, in comparison to the other activities of natural gas extraction, the flaring emission of criteria air pollutants and other air emissions of concern are insignificant.

The flaring rate of natural gas is necessary to apply the above emission factors to a unit of natural gas production. Flaring rates are highly variable and depend more on the production practices and condition of equipment at an extraction site that the type of natural gas reservoir. Thus, flaring rates have been parameterized in the model to allow uncertainty analysis. However, each natural gas extraction process of this analysis includes a default flaring rate that is based on a report by the U.S. Government Accountability Office (2004). The flaring rate is 0.30 percent for gas from coal bed methane.

Dehydration

Dehydration is necessary to remove water from raw natural gas, which makes it suitable for pipeline transport and increases its heating value. The configuration of a typical dehydration process includes an absorber vessel in which glycol-based solution comes into contact with a raw natural gas stream, followed by a stripping column in which the rich glycol solution is heated in order to drive off the water and regenerate the glycol solution. The regenerated glycol solution (the lean solvent) is recirculated to the absorber vessel.

A reboiler is used to heat the fluid in the stripper column; due to the heat integration of the absorber and stripper streams, the reboiler, which is heated by natural gas combustion, is the only equipment in the dehydration system that consumes fuel. The reboiler duty (the heat requirements for the reboiler) is a function of the flow rate of glycol solution, which, in turn, is a function of the difference in water content between raw and dehydrated natural gas. The typical water content for untreated natural gas is 49 lbs/MMCF. In order to meet pipeline requirements, the water vapor must be reduced to 4 lbs/MMCF of natural gas (EPA, 2006). The flow rate of glycol solution is 3 gallons per pound of water removed (EPA, 2006), and the heat required to regenerate glycol is 1,124 Btu/gal (EPA, 2006). By factoring the change in water content, the glycol flow rate, and boiler heat requirements, the energy requirements for dehydration are 8.0 Btu/kg of dehydrated natural gas. Assuming that the reboiler is fueled by natural gas, this translates to 1.5E-04 kg of natural gas combusted per kg of dehydrated natural gas.

The air emissions from the combustion of natural gas used by a dehydrator reboiler are based on EPA emission factors for natural gas combustion in industrial equipment (API, 2009).

In addition to absorbing water, the glycol solution also absorbs methane from the natural gas stream. This methane is lost to evaporation during the regeneration of glycol in the stripper column. Flash separators can be used to capture methane emissions from glycol strippers; however, this analysis assumes that flash separators are not used, resulting in methane emissions. The emission of methane from glycol dehydration is based on emission factors developed by the Gas Research Institute (API, 2009). Based on this emission factor, 3.4E-04 kg of methane is released for every kilogram of natural gas that is dehydrated.

Water Use and Quality

Coal Bed methane extraction results in the production of a substantial amount of water, and does not require water inputs for methane extraction (U.S. Geological Survey 2000). Instead, water contained in methane-bearing coal layers is extracted via extraction wells. As more and more water is extracted, the rate of release of methane increases. The water use and quality data used by this unit process are representative of approximately average discharge conditions (U.S. Geological Survey 2000).

Figure 1: Unit Process Scope and Boundary

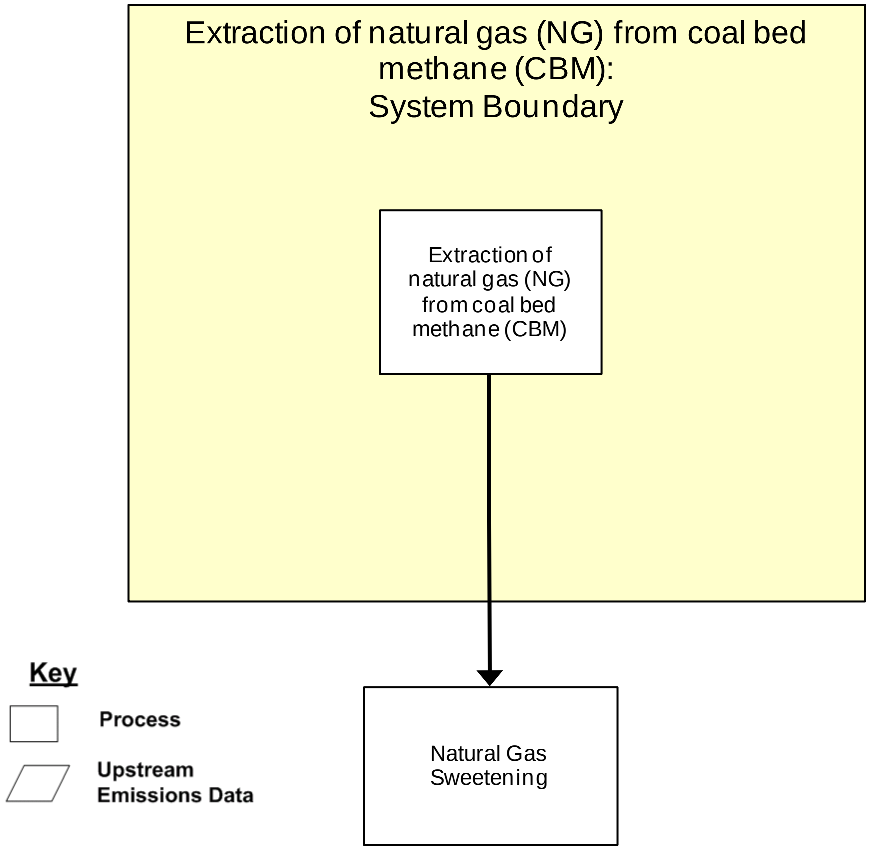

Table 1: Properties of CBM Wells

Property	Value	Source
U.S. supply share	7.5%	EIA 2009
Well capacity	800,000 ft^3/day	ALL Consulting 2004
Well locations	U.S. Rocky Mountain Region	ALL Consulting 2004
Flaring rate	0.30%	US GAO 2004

Table 2: Unit Process Input and Output Flows

Flow Name*	CBM NG well	Units (Per Reference Flow)
Inputs		
Natural Gas, CBM	1.0417	kg
Outputs		
Natural Gas, CBM	1.00	kg
Carbon dioxide [Inorganic emissions to air]	1.1201E-01	kg
Methane [Organic emissions to air (group VOC)]	1.5568E-03	kg
Nitrous oxide (laughing gas) [Inorganic emissions to air]	1.0481E-07	kg
Nitrogen oxides [Inorganic emissions to air]	3.8083E-03	kg
Sulphur dioxide [Inorganic emissions to air]	5.4884E-07	kg
Carbon monoxide [Inorganic emissions to air]	2.9589E-04	kg
NMVOC (unspecified) [Group NMVOC to air]	1.1014E-04	kg
Dust (PM10) [Particles to air]	9.3219E-06	kg
Water (wastewater) [Water]	5.7368E+00	kg
Barium [Inorganic emissions to water]	3.5568E-03	kg
Bicarbonate [Inorganic emissions to water]	2.5154E-02	kg
Calcium[Inorganic emissions to water]	6.1558E-04	kg
Chloride [Inorganic emissions to water]	1.2380E-02	kg
Magnesium [Inorganic emissions to water]	2.0314E-04	kg
Manganese [Inorganic emissions to water]	1.8358E-04	kg
Sodium [Inorganic emissions to water]	1.1916E-02	kg
Sulfate [Inorganic emissions to water]	5.0021E-05	kg

Total Dissolved Solids [Inorganic emissions to water]	5.0753E-02	kg

* **Bold face** clarifies that the value shown *does not* include upstream environmental flows. Upstream environmental flows were added during the modeling process using GaBi modeling software, as shown in Figure 2.

Embedded Unit Processes

None.

References

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Section III: Document Control Information

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Section IV: Disclaimer