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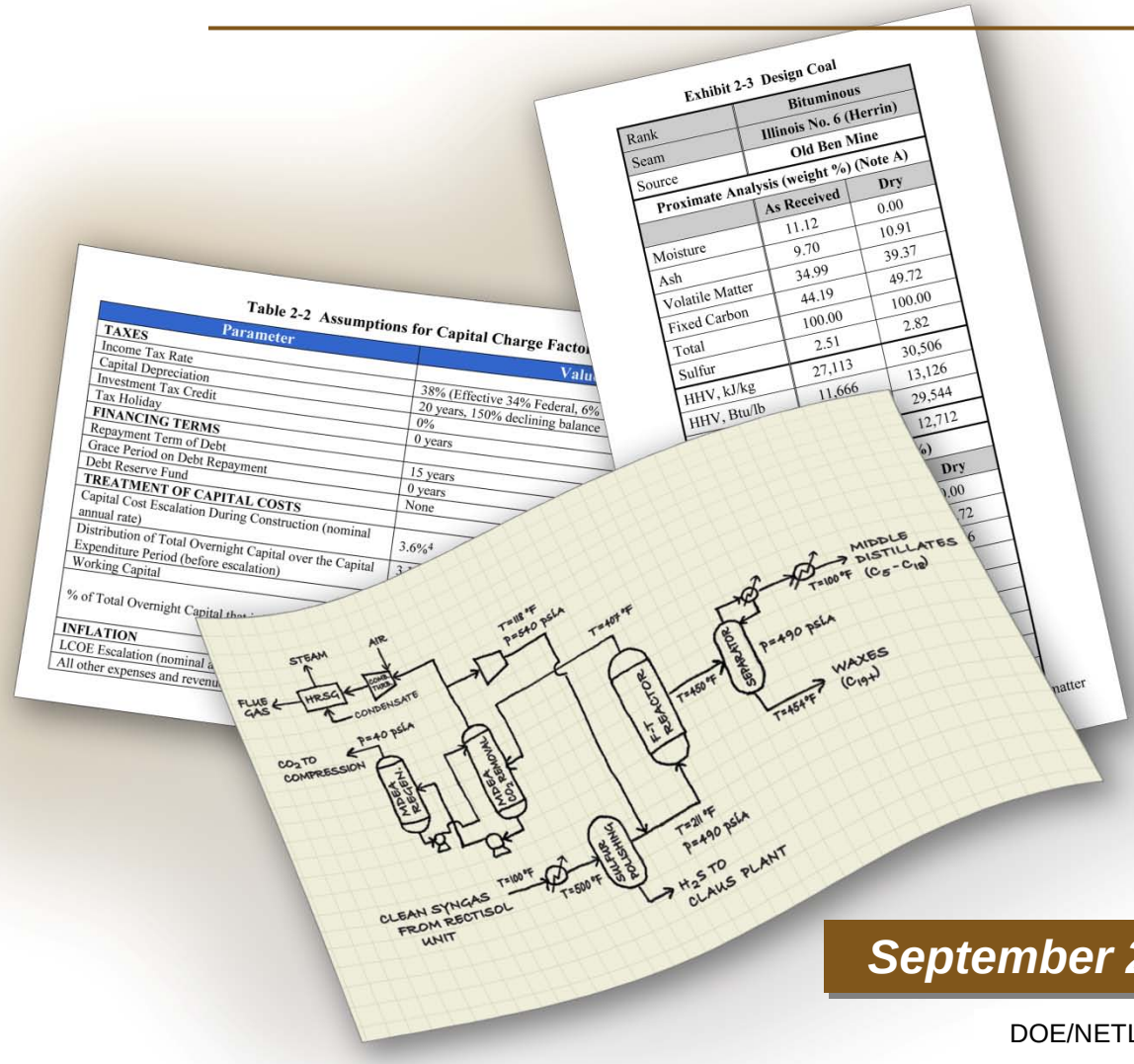
QUALITY GUIDELINES FOR ENERGY SYSTEM STUDIES

Methane Emissions from Mining Illinois Basin Coals



September 2010

DOE/NETL-2010/1445

NATIONAL ENERGY TECHNOLOGY LABORATORY

U.S. DEPARTMENT OF ENERGY

Quality Guidelines for Energy Systems Studies
Methane Emissions from Mining Illinois Basin Coals

Summary

Methane emissions resulting from the release of methane trapped in coal beds can have a significant impact on the life cycle greenhouse gas (GHG) emissions associated with coal production. These emissions vary dramatically by coal rank, specific seam, and seam depth and thickness. This is particularly true of underground mines, where 50 of the nation's 600 active underground mines are responsible for 98% of all methane emissions.

Various methods can be utilized to mitigate methane emissions, although at present these technologies have only seen limited deployment domestically due to lack of clear incentives or other barriers such as unclear ownership of rights to the gas, proximity of methane to market or a lack of desire to invest in new processes. Despite these factors, coal mine methane (CMM) recovery and use continues to grow, with over 46 billion cubic feet (Bcf) recovered domestically in 2006 – a 10% increase from 2003.[1] The U.S. Department of Environmental Protection (EPA) reports that of the 50 mines identified as potential candidates for CMM recovery (CMMR), 14 mines have implemented recovery strategies.[1] It is expected that deployment will increase dramatically for gassy mines in the event that carbon regulation is passed, due to the potential cost associated with emissions: methane emissions would incur a cost 25 times higher than carbon emissions based on their increased global warming potential (GWP).

This paper explores methane content and emissions associated with mining Illinois Basin coals such as Illinois No. 6. Illinois Basin bituminous coals tend to have a higher gas content than other bituminous coals, but the range of values is quite large, with methane contents as low as 10 standard cubic feet per ton of coal (scf CH_4/ton) and as high as 250 scf CH_4/ton being reported. As the methane content of the coal does not account for methane which has desorbed into the surrounding rock strata, specific methane emissions resulting from mining this coal will be even higher, with a 50% increase in emissions expected.

Background

The formation of coal occurs by a process called coalification, in which biomass is converted to coal over the course of millions of years under high pressures and temperatures. Methane gas is formed as part of this process and a portion of this methane remains in the coal seam and surrounding rock strata as coalification continues. The amount of methane that remains in the coal is primarily a function of the amount of pressure the coal seam is under, and hence the depth of that seam.[1] A good guideline, is that the higher rank (and often deeper) bituminous coals are likely to contain more methane than the younger, sub-bituminous coals, with the sub-bituminous coals likewise containing more CMM than lignite coals. This is only a guideline, however, as the methane content of different coals varies widely, across coal types, basins, and even within the same basin.

During mining operations, this coal mine methane CMM is released, resulting in a GHG emission, but the exact emissions are dependent on the type of mining – surface, underground (long-wall versus room-and-pillar) – methane content of the coal, and end use of the coal. These issues make the estimation of CMM emissions rates difficult and result in a significant level of uncertainty. Determining emissions levels are further complicated by variables such as length of time before usage (CMM desorbs at different rates for different coals), amount and type of coal preparation – particle size ground to, washing, drying – and conversion technology used, even down to the gasifier choice.[2]

[1]The deeper the coal seam, the greater the pressure and the more methane that remains physically absorbed to the coal. In shallow seams, the methane naturally migrates out of the coal seam and eventually into the atmosphere. Migration occurs in deeper seams, but the rate is limited such that migration is often limited to the surrounding rock strata.
[2] Different gasifiers have different feed requirements and the different coal preparation systems can result in a different fate for any methane remaining in the coal. For example, in a slurry-fed gasifier, methane is more likely to remain in the coal and/or transport gas as it

CMM presents a safety hazard for mining operations in addition to its role as a fugitive GHG emission. Methane levels in the mining area must be maintained below 1% (by volume) by Mining Health and Safety Administration (MHSA) and Operational Safety and Health Administration (OSHA) regulation. Methane levels are traditionally reduced by operating ventilation systems at excess capacity to ensure that methane levels stay low, or by drilling gob holes. Gob holes are holes drilled from above-ground into the coal seam or surrounding strata prior to mining, such that methane can escape through these holes, thereby reducing the amount of methane which can escape into the mine during operations. In some cases, this methane is captured, either for use in mining equipment (including ventilation air heating) or sale.

In addition to gob holes, numerous other CMM recovery technologies and techniques are available and in 2006, more than 46 Bcf of methane was captured using these technologies. [1] Different levels of methane recovery can be achieved with different techniques, and similarly, the quality of the gas will vary depending on the technique used. CMM removal (CMMR) rates of up to 70% drainage efficiency have been achieved with existing technologies and the potential for increased efficiencies may be possible depending on the incentive and coal seam in question.[3] [1] The EPA's *Identifying Opportunities for Methane Recovery at U.S. Coal Mines* details many of the currently available technologies and their efficacies. [1]

It seems likely that operators of gassy mines will implement "best practice" CMM recovery methods to avoid GHG emissions and to supplement existing mine safety requirements in the event that carbon legislation is enacted.[4] Under certain circumstances – high natural gas prices, close proximity to pipelines or markets – more aggressive techniques may be used to increase the quality or quantity of gas recovered. Other factors such as limitations placed on the GHG emissions profile of the finished energy product (be it electricity or fuels) or high GHG emissions values will also to play a role in how widespread deployment becomes.

Methane Emissions from Illinois Basin Coal Mining

Table 1 describes the variability of different coal methane contents and emissions levels published for Illinois Basin coal seams. The first column describes the mine evaluated, or any additional information if the value represents an average reported value. The "Coal Type" column describes the specific coal evaluated, which includes coals such as the Illinois #6 coal utilized in this study (also referred to as Herrin (No. 6)), Illinois #5 (a slightly deeper seam than Illinois #6 and also referred to as Springfield (No. 5)), to generic values reported for Illinois Basin coals.

The "Methane Content" describes the in situ methane content of the coal. This is the actual methane content of the coal, a portion or all of which may desorb from the coal after it is removed from the mine and prior to use. This methane content does not account for methane which may have desorbed into the surrounding rock strata over time. Methane content of Illinois Basin coals appear to typically fall within the range of 50 to 150 standard cubic feet of methane per short ton of coal (scf CH_4/ton coal), with the average values likely to be on the lower end of this range based on emissions levels from what are considered to be gassy mines, which start at 71 scf CH_4/ton coal. [1, 2, 3]

The "Specific Emissions" column describes both the average methane emissions over multiple years (obtained by dividing the estimated methane emissions by the rate of coal production) as well as the minimum and maximum annual emissions over the data collection period. Up to 8 years of data is available, during the 1999 to 2006 time period (depending on which mines were monitored and when). [1, 2] These emissions are the actual methane emissions associated with coal mining and account for methane degassing from the coal itself, as well as the surrounding rock strata. As shown, the specific emissions associated with coal production can vary widely from year to year. This variability can be simply the result of changes in coal production – if production is reduced but the coal continues to degas, the specific emissions increase although the net

is fed into the gasifier than in a dry-feed system, where the coal-drying process is likely to drive off volatiles such as methane along with the water, resulting in fugitive methane emissions.

[3] Increased methane removal efficiencies can often be achieved by drilling bore holes at a closer spacing , by pulling a vacuum on the holes, or utilizing a sweep gas. However, all of these come at an additional cost. Regardless, some CMM is likely to remain strongly bonded to the coal itself and will only desorb upon drying or use.

[4] Best practice CMM recovery methods include the drilling of gob wells (used by more than 23 mines in the U.S.) and horizontal boreholes (used by 9 U.S. mines). [1]

emissions may actually fall off – or may be due to operational or sampling issues, such as a reduction of mining operations on the day the sampling occurs or variability in sampling times/days/locations. [1, 2] Due to the variability and uncertainty involved, it is difficult to draw conclusions as to how emissions change over time from the facility.

An average value for all Illinois #6 coal is also listed in the "Annual Emissions" column. This metric was reported in NETL's recent *Life Cycle Analysis: Integrated Gasification and Combined Cycle (IGCC) Power Plant* report. [6] This value represents the average emissions from the Galatia Mine between 2002 and 2006. This metric is also consistent with the extrapolation of methane emissions from mining based on the higher end of the average Illinois Basin coal methane content (150 scf CH_4/ton), if it is assumed that 50% of the methane emissions associated with coal mining is due to gas in the rock strata surrounding the coal. [10] This assumption is based on the estimate that gob wells can reduce mining emissions by 50% and therefore 50% of the methane is in the surrounding strata. [1]

Approach for Quantifying Methane Emissions from Mining Illinois #6 Coals

The question of how to quantify CMM emissions from an energy facility fired on Illinois #6 is a difficult one. Where possible, actual methane emissions data from the mine the coal is sourced from should be utilized. If that information is not available, other approaches may be taken based on the assumptions inherent in the study.

One approach is to perform a bounding analysis to determine the effects of gassy versus non-gassy coals on overall emissions. This is the approach taken in a recent NETL study – *Polygeneration of Fischer-Tropsch Diesel Fuel and Electricity from Coal* – where a bounding analysis was performed by evaluating three scenarios: (1) CMM is present at a relatively high level in the coal and no attempt to mitigate emissions are taken, (2) CMM is present at the same level as in scenario (1) but best practice CMM recovery techniques are utilized to reduce emissions, and (3) CMM is present in concentrations on the low end of the range expected for Illinois #6 coal seams.[7] In this analysis, a CMM value of 360 scf CH_4/ton was used in scenarios (1) and (2) described above, although these emissions are of course reduced in scenario (2) based on CMM recovery operations. In scenario (3), the lower estimate of average gas content of 50 scf CH_4/ton for Illinois basin coals was extrapolated to a specific emissions level of 100 scf CH_4/ton of coal mined, again assuming that 50% of the methane emissions associated with coal mining is due to gas in the rock strata surrounding the coal. [1]

Table 1. Coal Mine Methane Content and Emissions Levels from Illinois Basin Coal Seams [1, 2, 3, 4, 5, 6]

Illinois Basin Mines/Profiles	Coal Type	Methane Content (scf CH_4/ton coal)	Specific Emissions[1] Average (Min – Max) (scf CH_4/ton coal)
Baker Mine (now closed)* [11]	W. Kentucky #13	Not Reported (n/r)	270 (179 – 898)*
Dotiki Mine [10]	W. Kentucky #9	n/r	49 (34 – 71)*
Elkhart Mine [11] (delisted due to reduced emissions in 2006)	Illinois #5 (Springfield)	n/r	106 (79 – 52)*
Galatia Mine [10, 11]	Illinois #5 (Springfield)	n/r	408 (238 – 509)
Gibson Mine [10, 11]	Illinois #5 (Springfield)	n/r	315 (264 – 406)**
Pattiki Mine [10]	Illinois #6 (Herrin)	n/r	281 (167 – 704)*
Wabash Mine (now abandoned) [10, 11]	Illinois #5 (Springfield)	n/r	341 (189 – 639)
Willow Lake Portal Mine [10, 11]	Illinois #5 and #6	n/r	119 (86 – 140)
Average of Gassy Illinois Basin Mines [10,11]			***268***
Average of Gassy Mines Producing Illinois #6 [10, 11]			***180***
Low Gas Content [12]	**Illinois Basin (Not Specified)**	**10**	n/a
Average Range for Illinois Coals [12]	**Illinois Basin (Not Specified)**	**50 – 150**	n/a
High Gas Content [12]	**Illinois Basin (Not Specified)**	**250**	n/a
Jefferson County, Il [14]	**Illinois #5**	**31**	n/a
Jefferson County, Il [14]	**Illinois #6**	**62**	n/a
Underground Mined Coal [13]	**Illinois Basin (Not Specified)**	**57**	n/a
Average for Illinois #6 [15]	**Illinois #6**	**N.R.**	**360 (n/a)**

[1] Specific Emissions provide an estimated emission rate per ton of coal mined. The estimate is an extrapolation based on quarterly ventilation system sampling which is then extrapolated to an emission rate based on the annual coal consumption figures. Average specific emissions rates are based on eight years of data unless noted with a "*" (five years) or "**" (six years). Data limitations were due to mines opening, closing, or the cessation of monitoring based on reduced emissions levels. [1, 2]

Another approach, used in the *Life Cycle Analysis: IGCC Power Plant* report, was to assess different methane levels and different levels of capture. To wit:

> *The CH_4 emissions from coal bed methane (CBM) in the base cases were based the average annual CH_4 emitted (between 2002 and 2006) per short ton coal produced at the Galatia mine (EPA, 2008b).* ***The average value, 360 standard cubic feet (scf)/ton coal, assumed all CH_4 released from the coal bed was emitted to the atmosphere.*** *However, some coalmines have begun to incorporate a CBM recovery process, which captures CH_4 to either sell as a co-product or create on-site energy generation. EPA estimates that 20-60 percent of liberated CH_4 could be recovered using these processes (EPA, 2008b). Therefore, sensitivity analysis was performing assuming a 40 percent CH_4 recovery (216 scf CH_4/ton coal emitted) during Stage #1 of both cases. In addition, the CH_4 emissions reported for the Galatia mine between 2002 and 2006 range from 238 to 464 scf/ton. Considering the calculated standard deviation of 90 scf/ton, a high-emission case was run at 450 scf/ton to determine the total GWP when emissions were higher than the base case.*

Whatever approach is utilized, transparent accounting of the methodology and rationale behind the use of that methodology should be reported.

Conclusions

There is a wide variability in the methane content of coal and the specific emissions of methane from coal mining. This is true across different coal ranks, seams, and even mines. This paper has illustrated the variability in methane content across coals in one basin and how emissions from a particular coal seam can vary from mine to mine.

Illinois Basin bituminous coals tend to have a higher gas content than other bituminous coals, but the range of values is quite large, with methane contents as low as 10 standard cubic feet per ton of coal (scf CH_4/ton) and as high as 250 scf CH_4/ton being reported. As the methane content of the coal does not account for methane which has desorbed into the surrounding rock strata, specific methane emissions resulting from mining this coal will be even higher, with a 50% increase in emissions expected. Specific methane emissions as high as 900 scf CH_4/ton have been reported from an individual mine, although this was one of the 50 mines the EPA has identified as the most gassy in the nation.

Technologies exist for the avoidance of methane emissions from coal mines but they are not widely deployed at present. It is likely that operators of gassy mines will implement “best practice” CMMR methods to avoid GHG emissions and to supplement existing mine safety requirements in the event that carbon legislation is enacted.[5] These technologies may be deployed under other circumstances, such as high natural gas prices, close proximity to pipelines or markets, or limitations placed on the GHG emissions profile of the finished energy product (be it electricity or fuels), as has been seen by a 10% growth in the industry between 2003 and 2006.

In evaluating the impact of CMM emissions in systems analyses associated with the use of coal, it is critical to use a transparent accounting of the methodology as the choice of a low or high CMM emissions profile could dramatically impact the results of the study. The rationale behind the use of that methodology should be reported and a sensitivity of bounding analysis is often warranted in order to illustrate the sensitivity of results to CMM emissions levels.

[5] Best practice CMM recovery methods include the drilling of gob wells (used by more than 23 mines in the U.S.) and horizontal boreholes (used by 9 U.S. mines). [1]

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Contacts

Thomas J. Tarka, PE
Senior Energy Systems Engineer
Office of Systems, Analyses & Planning
National Energy Technology Laboratory
626 Cochrans Mill Road
P.O. Box 10940
Pittsburgh, PA 15236
412-386-5434
thomas.tarka@netl.doe.gov

John G. Wimer
Director, Systems Division
Office of Systems, Analyses & Planning
National Energy Technology Laboratory
3601 Collins Ferry Road
P.O. Box 880
Morgantown, WV 26507
304-285-4124
john.wimer@netl.doe.gov