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OUTREACH PROGRAM

U.S. Surface Mines Emissions Assessment

U.S. Environmental Protection Agency
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Executive Summary

The current surface mine methane emissions estimation protocol used by the U.S. Environmental Protection Agency (U.S. EPA) involves the use of a Tier 2 approach by using basin-specific gas contents, basin-specific coal production, and a nationwide emission factor. The IPCC report Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories states “It is not feasible to collect mine-by-mine Tier 3 measurement data for surface mines”; however, efforts have been made to develop a mine-specific method closer to Tier 3 for determining emissions related to surface mining activities. In order to make recommendations for improvements to the U.S. methodology, various aspects of methodologies using a Tier 3 approach that were studied as part of other projects were examined.

The purpose of this study was to look for ways to improve the surface mine methane (SMM) emissions estimation methodology through a review of the current information used to determine the SMM inventory. In order to assess the current methodology, the following data was collected:

- latest emissions factors used for other national inventories,
- updated gas contents for several U.S. coal basins,
- study of coal thicknesses and overburden depths at U.S. surface mines,
- analysis of unmined coal seams adjacent to mined seams at surface mines,
- recent surface mine emissions studies from Australia, Canada, and U.S. EPA,
- surface mine emissions measurement attempts by Australians and U.S. EPA,
- other applicable measurement technologies.

Based on the findings, areas of data improvement were identified and integrated into the existing methodology in order to recalculate the SMM emissions estimate for comparison purposes. In addition, various attempts at mine-specific methane measurements were analyzed and reviewed to determine the possibility of combining or using other methods. Finally, the location of the gassiest surface mines in the U.S., and mines where meaningful pre-drainage (emissions avoided) could occur were identified.

1.0 Background

Currently, surface coal mines account for 67 percent of U.S. coal production, but constitute only 16 percent of the coal mine methane emissions. The primary reason for this is due to the relatively low gas content of the coals that are extracted from surface mines. The low gas content of these coal seams is likely related to the shallow depth of burial, and the fact that some are lower rank with commensurately lower gas adsorption capacity. Unlike underground mines for which degasification and ventilation emissions data is readily available, mine-specific emissions measurements are generally not measured for surface mines because no measurements are required for safety reasons due to the low risk of accidents resulting from excessive methane concentrations. The current approach used for estimating surface mine methane emissions is to apply a Tier 1 global average emission factor, or Tier 2 country or basin-specific emission factor to the amount of coal produced. As a result, emissions from surface mines (and post-mining activities) are calculated by multiplying basin-specific coal production by a basin-specific gas content and then by the country-specific emission factor to determine methane emissions. The emission factor currently used by the U.S. is based on 200 percent of the in-situ gas content of the coal. More accurate surface mine methane emissions estimates are desired, as surface mining accounts for a larger fraction of coal produced.

2.0 Background Information on the U.S. Methodology

The first step used in estimating methane emissions from surface mining and post-mining activities is to segregate the surface mines geographically by coal basin and by state. The Energy Information Agency's (EIA) *Coal Industry Annual* reports state- and county-specific underground and surface coal production by year. To calculate production by basin, the state level data were grouped into coal basins using the basin definitions listed in **Table A-119** of Annex 3 of the *Inventory of U.S. Greenhouse Gas Emissions and Sinks*. For two states—West Virginia and Kentucky—county-level production data was used for the basin assignments because coal production occurred from geologically distinct coal basins within these states. **Table A-120** of the same publication presents the coal production data aggregated by basin.

Emission factors for surface mined coal were developed from the *in situ* methane content of the coal in each basin down to a depth of approximately 250 feet. Revisions were recommended for several of the gas contents used in the underground and surface coal mine inventories in a memorandum to EPA on July 31, 2003, based on analysis of additional gas content data. Additional publicly available gas content data such as raw data used in *Evaluation and Analysis of Gas Content and Coal Properties of Major Coal Bearing Regions of the United States*, EPA/600/R-96-065 and *Coalbed Methane Resources of the United States, AAPG Studies in Geology Series #17*, as well as data from USGS and individual state geological survey publications was uncovered and compiled. Analysis of this additional data resulted in the following changes in surface mine gas contents for each basin:

Table 2.0.1 – Recommended Revisions in 2003

Basin	Previous Gas Content (scf/t)	Revised Gas Content (scf/t)
Northern Appalachian	49.3	59.5
Central Appalachian	49.3	24.9
Black Warrior	49.3	30.7
Illinois	39.0	34.3
Rocky Mountain Basins*	15.5	--
Piceance	--	33.1
Green River	--	33.1
Raton	--	33.1
Uinta	--	16.0
San Juan	--	7.3
Northern Great Plains	3.2	5.8
Western Interior Basins**	3.2	--
Arkoma	--	5.4
Cherokee	--	34.3
Forest City	--	34.3
Gulf Coast***	--	33.1

Sources: Diamond et al., 1986, Kirschbaum et al., 2000, Rightmire et al. 1984 and Tewalt, 1986

*Rocky Mountain Basins: Due to discovery of additional data, gas contents were separated from one value (15.5 scf/t) for all Rockies basins to separate values for each basin.
**Western Interior Basins: Geologic information revealed Arkansas, Missouri, Kansas and Iowa coals are more similar to the Illinois Basin coals; therefore gas content values of these coals were reassigned.
*** It was determined that Texas and Louisiana coals are more similar to Raton Basin coals, therefore gas contents were reassigned.

As a result of the updates, the new gas content values were used for the 2002 and 2003 inventories. However, due to a lack of publicly-available data, several of the basins' gas contents were still in question.

Based on an analysis presented in EPA's *Anthropogenic Methane Emissions in the United States: Estimates for 1990* (1993), surface mining emission factors were estimated to be from 1 to 3 times the average *in situ* methane content in the basin. Therefore, a mid-case emission factor of 2 was applied to all *in situ* methane contents for surface mines. However, recent research has found that the foundation for the assumptions used in the 1993 report were based of two previous studies conducted by Environment Canada (1992) and U.S. EPA (Kirchgessner et al. 1992). Both of these studies have since been updated by the authors and the emission factor assumptions have changed.

Based on the current emissions inventory, approximately half, or 13, of the states with surface mining activities account for ~90 percent of the methane emitted to the atmosphere as a result of surface coal mining activities. For this reason, the primary focus of this report was on coal basins contained by these top emitting states. **Table 2.0.2** shows the relative ranking of states by coal production and methane emissions from 2000-2003.

Table 2.0.2 - U.S. Surface Coal Mine Production and Emissions

Surface Coal Production by State (thousands of tons)

State	2000	2001	2002	2003	% of 2003 Total	
Wyoming	338,048	368,749	373,161	376,270		52%
WestVA South	54,498	57,447	56,810	47,999		
Texas	48,488	45,042	45,247	47,517		
Kentucky, East	45,114	47,262	42,984	39,142		
Montana	38,352	39,143	37,386	36,962	547,890	76%
North Dakota	31,270	30,475	30,799	30,775		
Indiana	24,277	29,546	27,428	26,720		
New Mexico	27,320	28,937	27,163	20,499	625,884	87%
Arizona	13,111	13,418	12,804	12,059		
Pennsyl.	17,283	16,011	12,612	11,512		
Virginia	9,654	10,271	9,465	10,371		
Ohio	10,356	12,506	10,306	9,182		
Colorado	9,156	9,825	9,771	8,654	677,662	94%
Washington	4,270	4,624	5,827	6,232		
Illinois	3,802	5,671	6,383	5,655		
WestVA North	5,919	5,418	5,350	4,920		
Alabama	3,450	4,192	4,015	4,742		
Kentucky, West	5,552	5,676	5,569	4,300		
Louisiana	3,688	3,715	3,803	4,028		
Mississippi	802	604	2,305	3,695		
Tennessee	1,213	2,003	2,081	1,907		
Maryland	1,350	1,399	1,820	1,756		
Oklahoma	1,345	1,300	943	1,172		
Alaska	1,641	1,514	1,146	1,081		
Missouri	436	366	248	533		
Kansas	201	176	205	154		
Utah	-	-	268	25		
Arkansas	12	13	13	7		
California	-	-	-	-		
Iowa	-	-	-	-		
TOTAL	700,608	745,306	735,912	717,869		100%

Surface Mine Emissions by State (mcf)

State	2000	2001	2002	2003	% of 2003 Total	
Wyoming	3,786,138	4,129,991	4,179,403	4,214,224		20%
Texas	3,209,906	2,981,807	2,995,351	3,145,625		
WestVA South	2,714,000	2,860,861	2,829,138	2,390,350		
Kentucky, East	2,246,677	2,353,648	2,140,603	1,949,272		
Indiana	1,665,402	2,026,887	1,881,561	1,832,992		
Pennsyl.	2,056,677	1,905,309	1,500,828	1,369,928		
Ohio	1,232,364	1,488,211	1,226,414	1,092,658	15,995,049	76%
WestVA North	704,361	644,738	636,650	585,480		
Colorado	606,127	650,417	646,840	572,895		
Virginia	480,769	511,496	471,357	516,476		
Montana	429,542	438,400	418,723	413,974	18,083,874	86%
Illinois	260,817	389,057	437,874	387,933		
North Dakota	350,224	341,325	344,949	344,680		
New Mexico	398,872	422,487	396,580	299,285		
Kentucky, West	380,867	389,374	382,033	294,980	19,410,753	93%
Alabama	211,830	257,389	246,521	291,159		
Louisiana	244,146	245,942	251,759	266,654		
Mississippi	49,243	37,075	141,527	226,873		
Maryland	160,650	166,539	216,580	208,964		
Arizona	191,421	195,896	186,938	176,061		
Oklahoma	200,405	193,674	140,507	174,628		
Tennessee	60,407	99,759	103,634	94,969		
Washington	47,824	51,792	65,262	69,798		
Missouri	29,910	25,137	17,013	36,564		
Alaska	18,379	16,959	12,835	12,107		
Kansas	13,789	12,078	14,063	10,564		
Arkansas	1,788	1,937	1,937	1,043		
Utah	-	-	8,576	800		
California	-	-	-	-		
Iowa	-	-	-	-		
TOTAL	21,752,535	22,838,183	21,895,457	20,980,937		100%

Source: EIA, 2003

2.1 Sources of Fugitive Methane Emissions at Surface Coal Mines

There are three potential sources of fugitive methane emissions associated with surface coal mining. These are:

- Methane emitted by the coal excavated and processed during mining activities,
- Methane emitted by the coal and other gas bearing strata in the overburden and/or underburden exposed by mining activities, and
- Methane emitted by the overburden coal excavated and stored on site in waste piles.

For methane emissions covered by the first point above, the available methane emitted by the excavated and processed coal is the estimated total gas content of the material excavated. For the second and third points above, the available methane is more uncertain as it depends on a variety of factors such as gas content and thickness of the adjacent coal seams, permeability of the coals and other strata found in the overburden and underburden, overburden thickness, and the amount of disturbance to the mine floor and highwall as a result of mining.

The gas in coal and associated strata may be released during different stages in mining. Excavated coal will release methane as it is broken and removed from the highwall face, transported on site, and crushed and sized for transportation off-site. Overburden, inter-burden and uneconomic coal is normally dumped together with non-coal material in waste piles. The methane contained in these coals will be released as the material is excavated, broken, dumped, and later used as backfill.

In addition, methane emissions will also migrate out of the floor and highwall of the surface mine. The magnitude of the floor emissions will depend on several factors such as:

- gas content of the unmined coal beneath the mine floor,
- proximity of the coal seams to the mine floor,
- extent of disturbance of the coal and the effect this has on its permeability,
- amount of coal left in the floor, and
- presence of water.

The magnitude of emissions from the highwall will similarly depend on:

- gas content of the unmined coal remaining in the highwall,
- extent of disturbance of the coal near the highwall and the impact this has on the permeability, and
- presence of water.

2.2 Coal Gas Content

In order to better accommodate the differences in coal properties occurring among the gassy coal basins, it was determined that the gas contents of several of the coal basins needed updating. **Table 2.2.1** shows the recommended changes to gas contents used for surface mine emission factors, based on recent research. In summary, it is recommended that changes to gas contents of three coal basins and separating the Williston Basin coals in North Dakota from the Wyoming-Montana group are necessary. The reason is that the coal mined in North Dakota is lower rank (lignite) than Wyoming-Montana (bituminous, sub-bituminous). It is believed that the gas content of 5.6 scf/t previously used for the entire region is appropriate for the North Dakota coals only.

The coals in Washington and Alaska were also separated from the Wyoming-Montana group since they are slightly higher rank, however, no information could be found on shallow gas contents in these states. Recognizing the 5.6 scf/t value previously used for this region to be too low for bituminous coals, using an average western U.S. coal basin value of 16 scf/t (Kirchgessner 2003), until further work can be carried out to refine this value, is recommended.

Similarly, coal mined in Texas and Louisiana was found to be borderline sub-bituminous (Tewalt, 1986). It is thought that in many cases, these Eocene/Paleocene coals are similar to the Paleocene coals found in the Powder River Basin as they were formed in similar depositional environments. The previous gas content of 33.1 scf/t was said to be representative of deeper, sub-bituminous and bituminous coals in Texas. During a USGS Resource Assessment of Gulf Coast coals in 2000, two test wells were drilled into shallow coals in northeast Texas to determine the gas contents of the low-rank Wilcox coals. The gas contents of coals from these two test wells averaged 11.0 scf/t. For the time being, this content is more representative of the coals mined in the Gulf Coast. However, further research is warranted to refine this value.

Table 2.2.1 – Recommended Gas Content Changes to U.S. Coal Basins for Surface Mine Emissions

Coal Basin	Inventory Code	Major Coal Rank Mined	2003 Revised Gas Content (cf/t)	Recommended New Gas Contents (cf/t)	Comments
Northern App	NAB	Bituminous	59.5	59.5	Data compiled from USBM report
Central App	CAB	Bituminous	24.9	24.9	Data compiled from USBM and MRCP reports
Warrior	WRB	Bituminous	30.7	30.7	Data compiled from USBM report
Illinois	ILB	Bituminous	34.3	34.3	Data compiled from USBM and MRCP reports
S.West/Rockies	WTB	Bituminous			
S.West (NM, AZ, CA)		Bituminous	7.3	7.3	Data compiled from USBM and MRCP reports
Rockies (CO)		Bituminous	33.1	33.1	Data compiled from USBM and MRCP reports
Rockies (UT)		Bituminous	16.0	16.0	Data compiled from USBM and MRCP reports
N.Great Plains	NGP	Lignite	5.6	5.6	North Dakota mines lignite coal
Northern Rockies (MT,WY)	WYM	Sub-bituminous	5.6	20.0	Data compiled from USGS, and private sector
West Interior	WIN				
Forest City, Cherokee		Bituminous	34.3	34.3	Arkansas, Missouri, Kansas, Iowa coals similar to Illinois Basin
Arkoma (OK)		Bituminous	74.5	74.5	Data compiled from USBM and MRCP reports
TX, LA		Sub-bituminous	33.1	11.0	Texas & Louisiana mine borderline sub-bituminous coal
Northwest	NWB	Sub-bituminous	5.6	16.0	Washington, Alaska coals similar to Powder River Basin

Sources: Diamond et al., 1986, Kirschbaum et al., 2000, Rightmire et al. 1984 and Tewalt, 1986

The gas content used for surface mine emissions factors in the Wyoming area coals has been thought to be low, but the difficulty of obtaining more recent, publicly available data has hindered the completion of any comprehensive study. This lack of available data still exists, but sufficient data (from several different sources) during this latest attempt to justify increasing gas content values for the region was discovered. Ninety percent of the coal mined in Wyoming is from the Powder River Basin (PRB), which represents 47 percent of all surface coal production in the U.S. This magnitude of coal mining increases the significance of gas content-based emission factors from the PRB. The challenge of obtaining representative gas contents from the PRB include:

- most gas contents are taken at depths much deeper than 200 feet (overburden depth),
- the methane occurring in the coals seams is considered biogenic and therefore gas content is in flux, and
- high permeability of coals allows for ease of gas migration once coals have been dewatered.

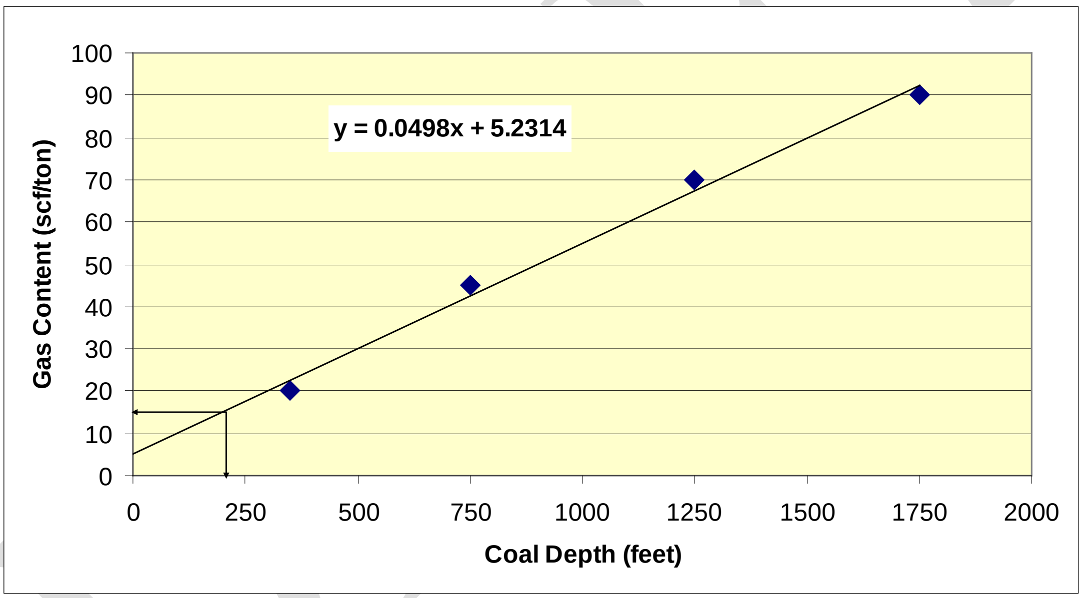
As part of a USGS-BLM coalbed methane study in 2001, two test wells were drilled adjacent to the Jacob Ranch Coal Mine in the PRB. The Jacob Ranch Mine is the fourth largest coal mine in the U.S., producing 35 million tons in 2003. One well drilled 500 feet from the highwall showed gas contents of 2 scf/t, while the second well drilled three miles from the face showed 12 scf/t.

Personal communications with John Wheaton, Research Hydrogeologist of the Montana Bureau of Mines and Geology[1], indicated that the gas content of PRB coals in Montana average 30 scf/t. Depths of the coals that produce this average amount of gas were not discussed as his research mainly focused on water quality issues. Gas contents at surface mine depths would be lower than average.

Using a table on the Wyoming State Geologic Survey (WSGS) website showing a summary of gas content values relative to coal [2]depth, a linear regression plot was generated to estimate the gas content at the mid-coal seam level for an average Wyoming surface coal mine overburden depth of 180 feet (210 feet total depth). The results produced a gas content of 15.7 scf/t.

Figure 2.2.1 shows the plotted data, regression, and equation used for the estimate. In further discussion with WSGS, it was agreed that the coals in southern Wyoming could contain higher volumes of gas due to their higher rank and the coals tend to be buried more deeply.

Figure 2.2.1 – Wyoming Geologic Survey Gas Content Summary



Source: WSGS, 2002

The parent company of a large surface mine operation was contacted about gas contents of the coal mined in the Wyodak/Anderson coal seam. The overburden depths at the surface mine are 250 feet which is deeper than average for Wyoming mines. While the gas content data from the coal in the CBM field adjacent to the mine is confidential business information, it was found to be greater than 20 scf/t. Taking all this into account, the gas content for surface mines in the Northern Rockies region (Wyoming and Montana) is estimated to be 20 scf/t.

[1] Personal communication

[2] Attempts to obtain the raw data used for the table from the WSGS were to no avail. The data originated from the U.S. BLM and based on discussions with their Wyoming field office, the source data is considered to be proprietary and would not be released

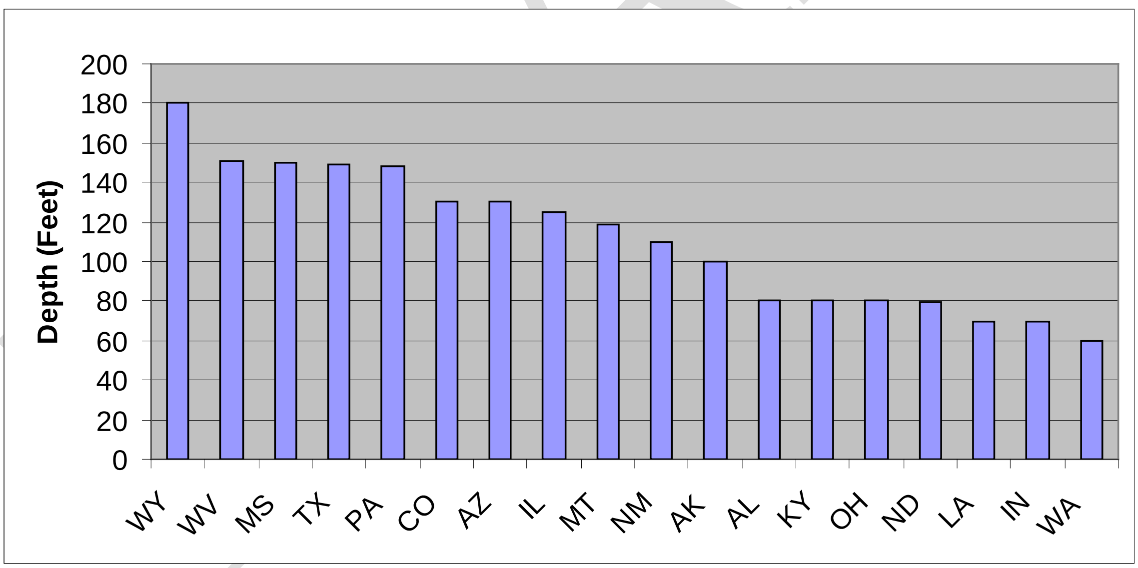
2.3 Emission Factor Used to Account for Over- and Underburden Coals

As stated in **Section 2.0**, the current emission factor used to account for fugitive methane emissions other than the coal being mined is a factor of two. The basis for this factor -- studies conducted by Environment Canada (1992) and U.S. EPA (Kirchgessner et al., 1992) -- has since been updated and the emission factor assumptions changed.

The original Environment Canada study estimated surface mining emission factors to be from one to three times the average *in situ* methane content in the basin. Since that time, Environment Canada has adapted a 1994 study conducted by Neil & Gunter, Ltd that quantified methane emission rates from underground and surface coal mines throughout Canada (King, 1994). Using this Tier 2-3 hybrid approach, Canada applied emissions factors for mines categorized by mine type, coal basin, and coal rank using mine-specific information gathered in the 1994 study. The resulting average emissions factor at surface coal mines of 8.6 scf/t includes a 50 percent increase of gas content data to account for unmined strata.

Attempts were made to compile surface mine data such as overburden depth, coal seam thickness, and net thickness of coal seams in the overburden and underburden to develop a matrix which could be used for basin-specific emission factors. It was determined that the data was too wide-ranging among coal mines, and that using average basin values was not necessarily an accurate assessment of surface mining activities. Overburden depths were compiled from the 2004 Keystone Coal Industry Annual for all surface mines with coal production greater than 200,000 tons. State-based average overburden depths were then calculated. **Figure 2.3.1** shows the results of the overburden study.

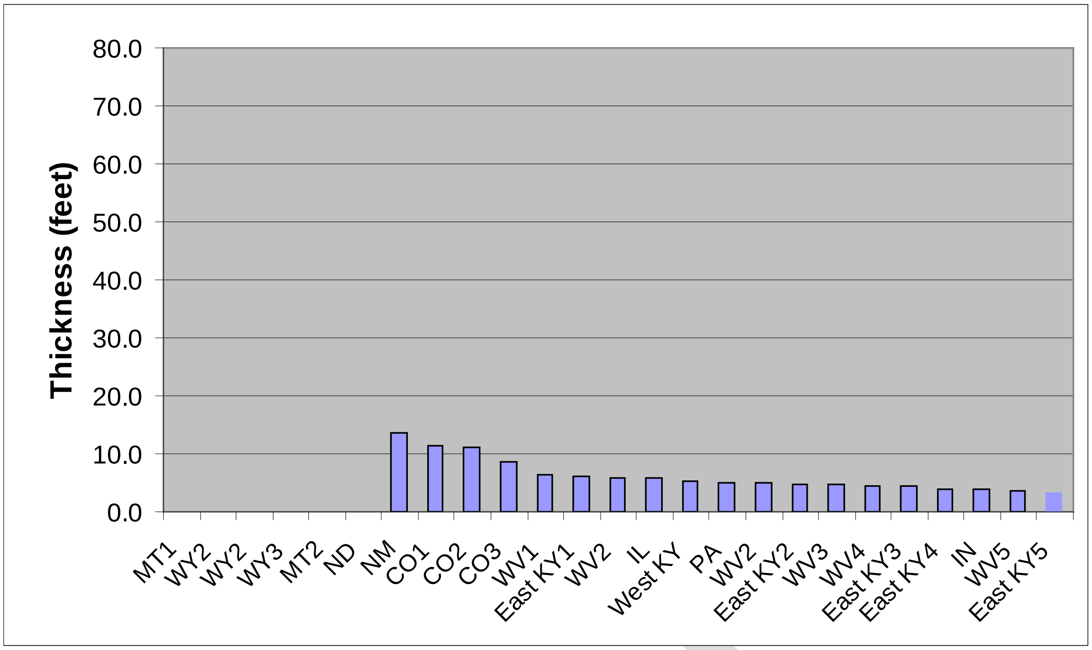
Figure 2.3.1 – Average Overburden Depth of U.S. Surface Coal Mines



Source: Keystone, 2004

The average coal seam thickness of the major coal seams mined at U.S. surface coal mines was also compiled. Information was used from the Department Of Energy's (DOE) EIA website to determine the coal thicknesses at the surface mine locations. In several states, multiple seams are mined and noted separately. **Figure 2.3.2** shows the summary of the coal seam thickness data.

Figure 2.3.2 – Average Coal Seam Thickness at U.S. Surface Coal Mines



Source: EIA, 2003

A desk study of rider coal seams located above or within 100 feet below the mined coal seams was conducted. Rider seams are adjacent coalbeds that are often thinner than the mined seam. These seams often contain methane contents similar to the mined coal seam. Quantifying the thicknesses of the coals proved difficult for several reasons:

- generalized stratigraphic columns are illustrative of the stratigraphic sequence and usually only give a picture of relative thicknesses of coals,
- the rider seams may pinch out laterally and are not always present at the surface mine locations, or, they can thicken laterally, and
- coal thickness can range widely, thus average thicknesses may not reflect conditions at the mines.

What can be concluded is that net rider seam thicknesses may never approach the mined seam thickness, thus providing some evidence that the factor of two currently used for the emissions factor may be considered conservative (too large). It is believed that a Tier 2 (basin-specific) emissions factor cannot be developed at this time due to a lack of data specific to the coal mines areas. The current calculation method is to simply multiply the volume of coal produced by 200 percent, which is supposed to account for 100 percent of the in situ content of the mined/ produced coal and any immeasurable amount of the methane in the adjacent strata. As a result, the Tier 1 value of 200 percent appears to be very conservative, and a lesser value might be more appropriate. As a result, further work needs to be carried out before a more accurate factor can be determined, and most-likely, this factor will be basin or region specific. There are several reasons this is proposed:

- The ratio of mined coal thickness to rider seam thickness varies greatly from basin to basin, or in some instances, there are no seams in the overburden.

- Horizontal permeabilities of both rider coals and mined coals vary from basin to basin, which can control the amount of gas that could potentially be emitted from the various seams as a result of mining.
- Overburden ratios (ratio of the thickness of overburden strata to the thickness of the mined seam) vary greatly from basin to basin.

2.4 Post-Mining Emission Factors

Currently, the same post-mining emissions factor is used for both underground and surface coal mines (32.5 percent of in-situ gas content of the coal). This was originally developed by a UK study (Creedy, 1993) of British coals. The actual amount of gas that escapes into the atmosphere will be a function of the methane desorption rate, the coal's original gas content, and the amount of time elapsed before coal combustion occurs. Some limited studies have been conducted using United States Bureau of Mines (USBM) gas content and desorption data and EIA route times for coal transportation. Kirchgessner (EPA, 2001) estimates the post-emissions factor to be 55-90 percent of in-situ gas content for underground coals mines and 72-78 percent for surface mines. Australia's greenhouse gas emissions methodology uses a 20 percent factor based on a 1994 study (Williams et al., 1993).

Due to the limited post-emissions data available and expert judgment, the current post-emissions factor appears to be representative of typical bituminous coals in the U.S.

2.5 Integrating Research into the Surface Coal Mine Emissions Inventory

The surface coal emissions inventory for the year 2003 was recalculated in two ways. First, the newly proposed gas contents from **Table 2.2.1** were incorporated; and second, using the 150 percent emissions factor instead of the current 200 percent factor. **Table 2.5.1** shows the inventory by U.S. coal basin using the former and revised gas contents. The nearly 10 Bcf increase in the Northern Rockies coal basins is partially offset by the 3 Bcf decrease in the Texas Gulf Coast coal area. The net change is an increase of approximately 7.5 Bcf (from 24.4 to 31.9 Bcf).

Table 2.5.1 – Comparison of 2003 Surface Mine Emissions Inventory Using Currently Used and Proposed Gas Contents[3]

	Previous Gas Content (cf/t)	Surface Mine Emissions (mmcf)	Post-Mining Emissions (mmcf)	Total Emissions (mmcf)	New Gas Content (cf/t)	Surface Mine Emissions (mmcf)	Post-Mining Emissions (mmcf)	Total Emissions (mmcf)
Northern App	59.50	3,257,030	529,267	3,786,297	59.50	3,257,030	529,267	3,786,297
Central App	24.90	4,951,066	804,548	5,755,614	24.90	4,951,066	804,548	5,755,614
Warrior	30.70	518,032	84,180	602,212	30.70	518,032	84,180	602,212
Illinois	34.30	2,515,905	408,835	2,924,740	34.30	2,515,905	408,835	2,924,740
S.West/Rockies (NM, AZ, CA)	7.30	475,347	77,244	552,591	7.30	475,347	77,244	552,591
S.West/Rockies (CO)	33.10	572,895	93,095	665,990	33.10	572,895	93,095	665,990
S.West/Rockies (UT)	16.00	800	130	930	16.00	800	130	930
N.Great Plains	5.60	4,972,878	808,093	5,780,971	5.60	344,680	56,011	400,691
Northern Rockies (MT,WY)	20.00	-	-	-	20.00	13,223,424	2,148,806	15,372,230
West Interior (Forest City, Cherokee)	34.30	47,128	7,658	54,787	34.30	47,128	7,658	54,787
West Interior (Arkoma)	74.50	175,671	28,547	204,218	74.50	175,671	28,547	204,218
West Interior (Gulf Coast)	33.10	3,412,279	554,495	3,966,774	11.00	1,133,990	184,273	1,318,263
Northwest	5.60	81,906	13,310	95,215	16.00	234,016	38,028	272,044
	Total	20,980,937	3,409,402	24,390,339		27,449,984	4,460,622	31,910,606

[3] Data used to develop this table was obtained during preparation of the annual Coal Mine Methane Emissions Inventory.

This net increase in the inventory is negated when an emissions factor of 150 percent rather than 200 percent is used to represent the additional emissions from overburden and underlying coal seams. **Table 2.5.2** shows the inventory by U.S. coal basin when using the new gas contents and the 150percent factor. The net change is an increase of approximately 0.6 Bcf (from 24.4 to 25.0 Bcf).

Table 2.5.2 - Comparison of 2003 Surface Mine Emissions Inventory Using Currently Used Gas Contents (with 200 percent emissions factor) and Proposed Gas Contents [4] (with 150 percent emissions factor)

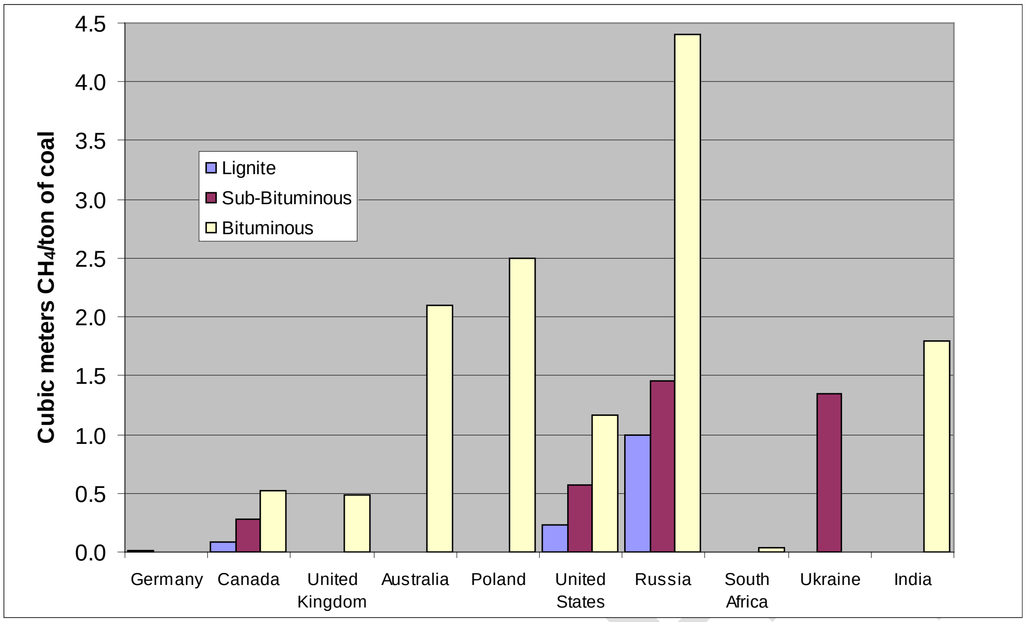
	Previous Gas Content (cf/t)	Surface Mine Emissions (mmcf)	Post-Mining Emissions (mmcf)	Total Emissions (mmcf)	New Gas Content (cf/t)	Surface Mine Emissions (mmcf)	Post-Mining Emissions (mmcf)	Total Emissions (mmcf)
Northern App	59.50	3,257,030	529,267	3,786,297	59.50	2,442,773	529,267	2,972,040
Central App	24.90	4,951,066	804,548	5,755,614	24.90	3,713,300	804,548	4,517,848
Warrior	30.70	518,032	84,180	602,212	30.70	388,524	84,180	472,704
Illinois	34.30	2,515,905	408,835	2,924,740	34.30	1,886,929	408,835	2,295,763
S.West/Rockies (NM, AZ, CA)	7.30	475,347	77,244	552,591	7.30	356,510	77,244	433,754
S.West/Rockies (CO)	33.10	572,895	93,095	665,990	33.10	429,671	93,095	522,767
S.West/Rockies (UT)	16.00	800	130	930	16.00	600	130	730
N.Great Plains	5.60	4,972,878	808,093	5,780,971	5.60	258,510	56,011	314,521
Northern Rockies (MT,WY)	20.00	-	-	-	20.00	9,917,568	2,148,806	12,066,374
West Interior (Forest City, Cherokee)	34.30	47,128	7,658	54,787	34.30	35,346	7,658	43,004
West Interior (Arkoma)	74.50	175,671	28,547	204,218	74.50	131,753	28,547	160,300
West Interior (Gulf Coast)	33.10	3,412,279	554,495	3,966,774	11.00	850,493	184,273	1,034,766
Northwest	5.60	81,906	13,310	95,215	16.00	175,512	38,028	213,540
	Total	20,980,937	3,409,402	24,390,339		20,587,488	4,460,622	25,048,110

2.6 Comparison of U.S. Gas Contents with International Values

To further analyze the U.S. surface mine methane emissions inventory, a study of several international surface mine methane gas contents was conducted for comparison with U.S. values. Literature regarding gas contents of surface mined coal was researched for several countries and coal was distinguished by rank. For each rank, the U.S. average emission factors appear to be close to median. For example, the U.S. value for lignite falls between the average factor for Germany and Russia (**Figure 2.6.1**). The U.S. average gas content value was also compared to the overall international average value. The U.S. average falls close to but below the overall average factor for each coal rank and appears low when plotted on the range of factors (**Figure 2.6.2**).

[4] Data used to develop this table was obtained during preparation of the annual Coal Mine Methane Emissions Inventory.

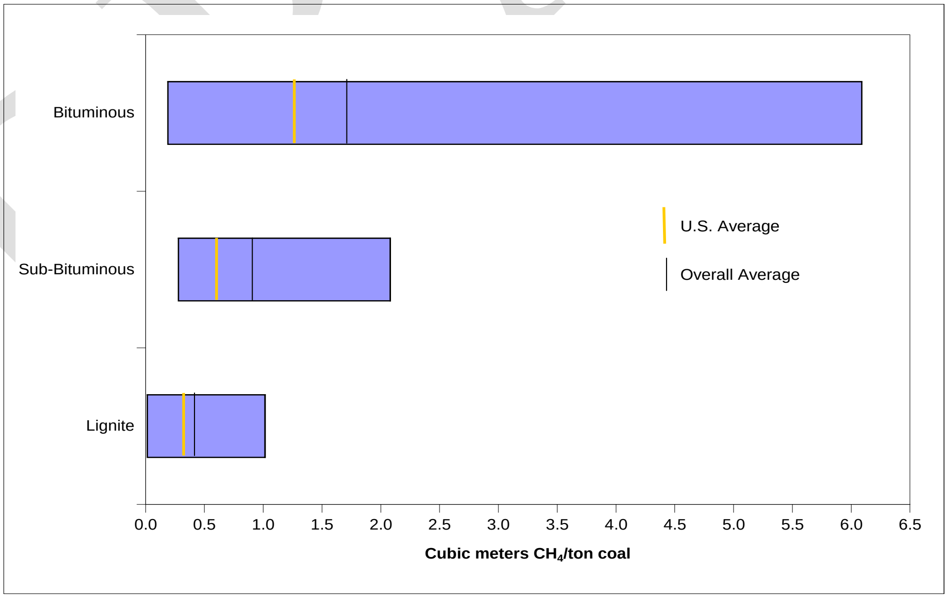
Figure 2.6.1 - CH_4 Gas Contents by Country and Coal Rank



Source: Izrael et al., 1997, KazNIIMOSK, 2002, Lloyd et al., 2005 and Personal communications with UNFCCC

Figure 2.6.1 compares several average surface mining gas content values including the U.S. average based on new gas content values. Most emission factor data was obtained from National Communications to the UNFCCC. The range of values for South Africa was obtained from Lloyd, et al. Data for Russia was obtained by applying the appropriate coal ranks to the gas contents found in Izrael, et al. Kazakhstan information was taken from KazNIIMOSK, 2002.

Figure 2.6.2 - Range of Worldwide CH_4 Gas Contents by Coal Rank



Source: Izrael et al., 1997, KazNIIMOSK, 2002, Lloyd et al., 2005 and Personal communications with UNFCCC

Figure 2.6.2 shows where the U.S. average surface mine gas contents fall within the range of worldwide gas contents for each coal rank. For all three coal types, the U.S. gas content is lower than the overall average. The ranges of gas contents by coal rank are shown in **Table 2.6.1**.

Table 2.6.1 - Ranges and Values of CH_4 Gas Contents in m^3 CH_4 / ton of coal

	Lignite	Sub-Bituminous	Bituminous
Germany	0.015		
Canada	0.088	0.28	0.19 - 0.85
United Kingdom			0.49
Australia			1.0 - 3.2
Poland			2.5
United States	0.16 - 0.31	0.57	0.21 - 2.11
Russia	1.0	1.1 - 1.8	2.9 - 5.9
South Africa			0.002 - 0.064
Ukraine		1.35	
India			1.8

Source: Izrael et al., 1997, KazNIIMOSK, 2002, Lloyd et al., 2005 and Personal communications with UNFCC

3.0 Review of Methane Measurement Technologies at Surface Coal Mines

This section summarizes two reported efforts made to develop methane emissions measurement protocols, one by U.S. EPA in 1991 and the other by Australia's CSIRO in 2003. Interestingly, the studies were vastly different in their approaches and conclusions, demonstrating the difficulty of developing a transparent measuring methodology for surface mine emissions on a site-specific basis.

3.1 Description of *Open-Path FTIR Spectroscopy and Modeling Techniques – U.S. EPA*

One previous effort to develop a methodology for estimating surface mine methane emissions was carried out by the U.S. EPA involving the use of open-path Fourier Transform Infrared spectroscopy (FTIR) and Gaussian-based plume dispersion modeling techniques. FTIR technology has been applied in measurement of hazardous air pollutants, and is accepted by EPA as one of the better technologies for measuring air pollutants in residential areas. Here, a methodology has been developed for applying the technology to measuring surface mine methane emissions. Kirchgessner et al. describe the results of the initial field trial of this methodology.

Use of the FTIR spectrometer, a remote-sensing device, was chosen by the authors over point sampling techniques because point sampling would present the need for an unreasonably large number of samples (as well as give rise to potential errors from sample line leaks or loss or production of gases in sampling containers). The open-path FTIR also accommodates the sizable plumes being emitted from surface coal mines, which can be over 1000 meters in width.

The initial mine site selected for measurement was the Caballo mine in Campbell County, Wyoming, which is located in the Powder River coal basin. Of six sites considered in the Powder River, Montana, and Illinois basins, Caballo was selected for its configuration and the fact that the location exhibited properties such as flat terrain where Gaussian dispersion modeling could be applied.

Methods Used in the Study

The methodology was developed using FTIR, meteorological measurements, and release of a tracer gas at known rates. The tracer gas used in this study is SF_6, which is non-reactive and does not naturally occur; thus, there is no ambient concentration to be concerned with. The open-path FTIR spectrometer directs a beam of infrared radiation along a path where it is reflected back to the spectrometer with mirrors. Smoke releases show surface mine emissions disperse in the direction of prevailing winds; thus, this study used a near ground-level measurement taken with the open-path FTIR sensor downwind of the mine. The reflected beam is subjected to absorption analysis to identify the gases present along the path and a path-integrated concentration is determined. The concentration measurement at the point of the FTIR path is then incorporated into a model which uses this value to estimate the emissions from the entire area based on the plume dispersion characteristics.

The plume dispersion properties were determined by the simultaneous release of SF_6 and CH_4. Using meteorological data (e.g. wind speed) obtained from a meteorological station located near the designated FTIR path, any available site-specific plume characteristics, and a known release of the tracer gas, standard Gaussian dispersion equations were applied to create a plume dispersion model for the methane plume from the surface mine.

The following simplified relationship was derived from integrating the standard Gaussian equation across the y direction and setting height equal to zero as the plume is a ground-level source:

$$C_{CWI} = \frac{2Q}{(2\pi)^{1/2} u \sigma_z}$$

where,

C_{CWI} = ground-level cross-wind-integrated concentration (g/m^2)
Q = emission rate (g/s)
u = average wind speed (m/s)
σ_z = vertical dispersion coefficient (m)

The equation can be used to assess dispersion characteristics by obtaining values of σ_z specific to the site given 1) a measured tracer gas concentration ($C_{CWI]}$) from an FTIR sensor, 2) a measured value of u from the meteorological station near the FTIR path, and 3) a known release rate Q from a tracer gas source. A number of σ_z values were determined based on tracer gas releases conducted at different distances upwind of the monitoring path. Using these values, a relationship of σ_z versus distance from the path was determined.

Also, a simpler method can be used to determine the plume's dispersion characteristics using fewer tracer gas measurements. Given Q for the tracer gas, the release location, wind speed (u), and wind direction, a plume dispersion model was used to predict C_{CWI} for the tracer gas plume. The model was run several times considering differing stability classes (Pasquill-Gifford atmospheric stability classes), producing a range of C_{CWI} values. The predicted C_{CWI} value closest to the measured value was used to define the atmospheric stability class present when the measurement was taken. CH_4 measurements were collected at this time so the atmospheric stability is applied to the CH_4 plume.

The model was run to predict methane concentrations along the measured FTIR path, and the predicted concentrations were compared with the measured values to calculate the actual methane release rate once incorporated into the plume dispersion model. The following relationship was used:

$$\frac{Q_{(actual)}}{Q_{(predicted)}} = \frac{\text{Concentration}_{(measured)}}{\text{Concentration}_{(predicted)}}$$

Measurements and Results

Preliminary ambient measurements were collected at the site before the methodology was applied. An organic vapor analyzer (OVA) was used to provide rough estimations of methane emissions. These preliminary measurements indicated that disturbed coal areas, such as those blasted, were likely to be the most significant source of CH_4 at the mine. Ambient measurements were also taken with the FTIR, upwind of the sampling area. The average background concentration measured was 1.64 ppm (the global average is 1.7 ppm). Background concentrations varied significantly, up to 0.5 ppm, between days 2 and 4 of sampling.

Calibration cell measurements were also taken at the site to assess the performance of the FTIR, and interpret results accordingly. The FTIR beam was passed through a chamber with a known CH_4 concentration. On average, the FTIR measurements appear to underestimate actual CH_4 calibration concentrations by about 20 percent. OVA measurements were also taken during sampling in order to compare with the FTIR data. The OVA data estimated higher concentrations than the FTIR measurements, when taken at the same time (7.0 ppm while the FTIR measured 4.0 ppm), confirming the FTIR measurements to be low.

The plume from the Caballo mine was split into east and west sections to be measured by the FTIR, as the maximum path length the FTIR sensor can measure is 650 meters which the mine's plume exceeded. The path lengths ranged from 375 to 525 meters. Longer path lengths are thought to have caused low FTIR measurement values due to the effect of light scattering, diluting the overall signal.

Estimated emission rates for the mine range from 0.70 to 6.31 m^3/min for the east side and 0.77 to 6.24 m^3/min for the west side. The east side emissions are higher, as expected, due to the presence of the coal blast area on the east side. The average east side emission rate was 1.85 m^3/min and the average west side emission rate was 1.45 m^3/min. Based on the average values for each side, the estimated total annual emissions from the Caballo mine are 1.74 million m^3/year (or 168 mcf/day). Emission factors reported in a later EPA study (Kirchgessner, 2001) range from 0.03 to 0.13 m^3 CH_4/metric ton of coal, with an average value of 0.09 m^3 CH_4/metric ton of coal (3.18 ft^3 CH_4/ton of coal).

In development of this methodology, the authors determined open-path FTIR spectroscopy and Gaussian based plume dispersion modeling to be a feasible approach for measuring methane emissions from large surface mines. In the initial study, it was noted that additional work is required primarily because methane concentration measurements determined by the FTIR were low (20 to 75 percent) based on preliminary measurements taken with an OVA. Kirchgessner (et al.) note later that the techniques measured emissions often within 15 to 20 percent of the known values obtained from validation by calibration cell measurements and usually within no more than 30 percent (2001).

3.2 Description of *Combined Measurements Methodology – Australia CSIRO*

Another effort to develop a method for estimating fugitive surface mine emissions was conducted for the Australian Coal Association (Saghafi et al. 2003). Briefly, the methodology combined several measurements, including gas content measurement of coal samples, surface emissions measured from exposed coal and interburden, and gas flow and gas composition measured from a surface borehole. The development of this methodology was completed in two coal basins in Australia; the Hunter Valley in NSW, and the Bowen Basin in Queensland.

Gas Content Method

The gas content of coal was measured based on three components in the following equation:

$$Q_m = Q_1 + Q_2 + Q_3$$

where,

Q_m = Measured gas content
Q_1 = Volume of gas lost during drilling
Q_2 = Volume of gas desorbed during the period between measuring Q_1 and crushing the sample
Q_3 = Volume of gas released after crushing

Coal samples were collected and sealed in leak tested canisters. The canisters can contain up to 3.0 kg of coal. The Q_1 component is only pertinent to fresh bore coal samples and is estimated by measuring the gas desorption rate over 20 to 30 minutes, fitting a desorption rate equation, and calculating the gas desorbed back to zero time. The volume of gas desorbed after drilling is typically measured over the time it takes to transport the sample to the laboratory or one to two days. Finally, the coal is crushed to < 200µm and the amount of gas desorbed during and after crushing are measured. The sum of these three components yields the measured gas content of the coal. For some samples, desorption of gas was monitored over a 6 week period to study the kinetics of desorption.

Direct Surface Emission Measurement Method

The second measurement in this methodology is the direct measurement of surface emissions from exposed coal and interburden. This is done by placing a chamber (**Figure 3.2.1**) over a 4 m^2 surface area and drawing ambient air through with a fan at a known rate to dilute the gas, such that gas concentrations are maintained within the range measurable by gas analyzers through which the gas is drawn. The methane content was measured with a Horiba hydrocarbon analyzer, using a laptop to record the data. Carbon dioxide was also measured. The surface emissions were calculated as emission fluxes expressed as volume of gas emitted per unit time and unit area of ground surface. The emission fluxes were calculated using the following expression:

$$Q = \frac{f_d\,(C_s - C_b)}{A}$$

where,

Q = Emission flux

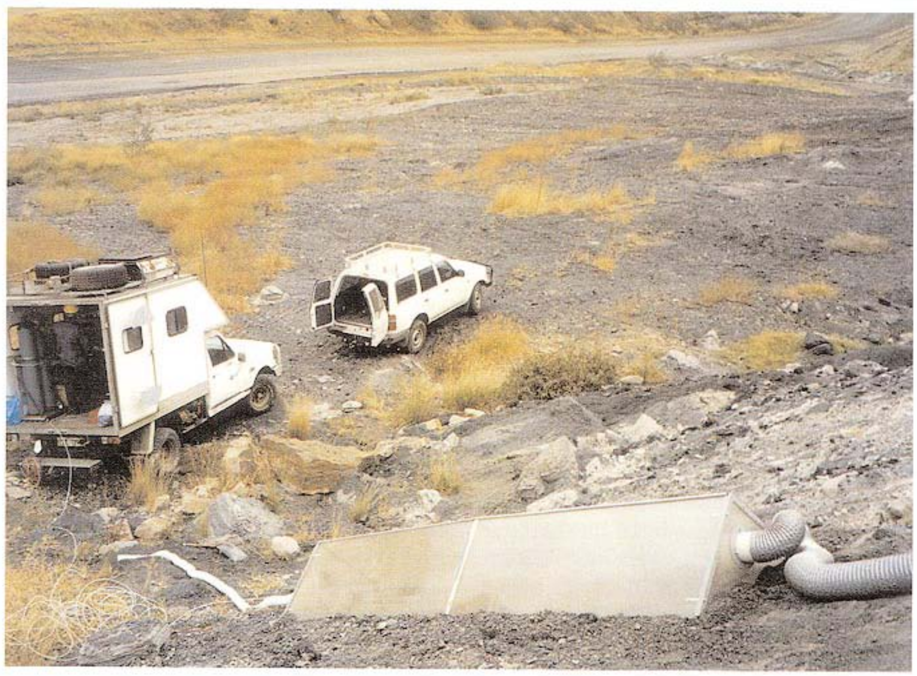
f_d = Dilution air flow rate

A = Area of the chamber

C_s = Steady state concentration of the seam gas in the chamber

C_b = Concentration of the seam gas in the dilution air flowing through the chamber

Figure 3.2.1 – CSIRO Chamber



CSIRO's special chamber on the surface of the spoil measuring flux of greenhouse gas emissions

Source: Saghafi et al. 2003

Borehole Measurement Method

The final measurement in this methodology is the measurement of gas flow and gas composition from surface boreholes that intersect coal seams. The study was carried out on a borehole in the Cheshunt region that was drilled in the middle of an undisturbed area to be mined through in approximately five years. Since it was desired to measure the gas flow from individual coal seams, as well as the total gas flow from the borehole, two methods were used to attempt isolating the zone for testing in order to measure gas flow from individual seams – use of impermeable layers of bentonite to isolate seams within the borehole, and the use of borehole packers.

Backfilling with bentonite proved unsuccessful due to its less than ideal sealing properties. The borehole packer method for measuring gas flow from individual seams was also unsuccessful where groundwater was present, as dewatering the boreholes with a pump was not possible with the packer in place. Where dewatering is not an issue, the packer method may find application. As a result, the total gas flow was measured using gas flow meters connected to a cap fitted to the borehole casing. Due to the necessary dewatering procedure, the water extracted from the hole was tested for gas content; however, the gas lost with the water was not significant.

Results

Gas content measurements were taken at both the Bowen Basin and Hunter Valley sites. At the Moura mine in the Bowen Basin, gas contents ranged from 0.50 m^3/t (CO_2 and CH_4) to 1.0 m^3/t with ~95 percent methane. At the other mines, Goonyella and Burton, in Bowen Basin, the content of the gas was almost entirely CO_2, with gas contents in the range from ~0.1 to 0.2 m^3/t. Back extrapolation of Moura mine gas content data showed that the Moura coal in Pit 5A could have had a higher initial gas content of ~1 m^3/t, where values obtained from testing were around 0.48 m^3/t. Extended time periods between uncovering the seam and mining could lead to underestimation of coal gas content. The variability of the gas content data demonstrates the importance of knowing length of time since the coal seams were uncovered.

Data from seven mines in Hunter Valley showed gas contents varying from ~0.07 to 1.6 m^3/t, with compositions ranging from nearly 100 percent CO_2 up to 70 percent CH_4. The larger gas contents had higher CH_4 compositions. At this site, gas desorption monitoring was performed, which brings up another concern with gas content measurement as a methodology. For one sample, 50 percent of the in situ gas was still present after 41 days with 10 percent still present after 144 days. This indicates significant amounts of gas leaving the mine in the coal. Further work is necessary to quantify this.

Direct measurement of surface emissions was also conducted at both sites. At the Moura mine, emission rates varied by more than a factor of ten, from ~0.4 to ~6 mg/s/m^2 (almost 100 percent CH_4). The other Bowen Basin mines had much lower rates, high variability, and were almost entirely CO_2. The Goonyella mine, for example, had emission rates vary from 0.02 to 0.45 mg/s/m^2 over essentially the same surface.

The gas content and composition derived from the borehole data varied as expected with depth. Higher gas content with greater CH_4 concentration (up to 90 percent for the deepest seam) resulted from measurement of deeper seams, while lower gas content with greater concentration of CO_2 corresponded with shallower seams. Gas contents varied from ~0.4 to 3.7 m^3/t.

Coal sampling for gas content measurements and direct surface emission measurement does not provide the data necessary for a Tier 3 methodology to determine emission factors for the mines studied, as it was determined that coals sampled at the surface have already lost some percentage of gas as a result of desorption processes once the coals were uncovered. Gas content measurements and surface emission rates varied widely in CO_2/CH_4 ratio as well as total gas content. The results exhibited variability due to: 1) dependence on the initial gas contained in the coal, 2) the time since the coal was disturbed, and 3) the mining method which affects the permeability of the surface layer and the rate at which gas desorbs.

Rather than accepting a methodology to measure emissions from active mines using all three measurements (gas content, direct surface emissions, and flow from boreholes), it is suggested that further work be carried out on measurements from boreholes to develop a methodology for estimating fugitive emissions after mine closure. Borehole emissions may approximate emissions from a standing high wall on mine closure, as opposed to emissions from an exposed coal seam that is measured with direct surface emission measurement.

Of the three measurement methodologies applied in this study, an approach similar to that at the Cheshunt borehole is required. The data obtained from a dedicated borehole, along with data from an extension of the exploration drilling program to include a limited number of gas content measurements could be used to develop a Tier 3 methodology.

3.3 Other Possible Measurement Technologies

Technologies that have been designed to measure methane leaks from natural gas pipelines may also be considered for measuring methane emissions from surface mines. One such technology is the duoThane® or active gas correlation radiometer (ACGR) pipeline monitoring solution created by Ophir Corporation. This system is specifically designed for long-path, perimeter measurements of methane and ethane from large area facilities such as landfills. This product has been used previously for pre- and follow up surveys of coalbed methane sites, and is considered applicable to measure surface mine plumes as well.

As an optically-based sensor, ACGR offers a solution to long-path perimeter monitoring. This is because the optical method can integrate along a line-of-sight, detecting the total trace gas concentration existing at any moment between the transmitter and the receiver. Trace gas concentrations can be monitored in a continuous fashion, and flux measurements can be readily achieved. When a facility or area is encircled with perimeter monitors, total emissions of the trace gas under study can be determined (Ophir, 2005). It is believed that a weakness of the attempt by EPA using FTIR was the use of only one monitor which may not have captured the total emissions occurring at the mine and that utilization of a series of perimeter monitors as applied here would be superior.

AGCR is a method of detecting trace gases using an active source and an optical correlation detection method. The optical correlation hardware compares the spectra of the gas of interest to that of the gas in the region under inspection. AGCR does not require laser sources, but instead uses broadband illumination (Spaeth et al, 2003).

The technologies developed by Ophir have been used for path lengths up to 900m, and representatives state that even longer lengths can be measured by dividing the area into smaller sections much like what was done on the east side of the Caballo mine in Kirchgessner's study. This system can measure trace concentrations as low as sub-ppm, as well as higher concentrations more applicable to surface mine emissions, given the area is divided into smaller sections as to avoid loss of the beam.

Other technologies have been explored for measuring natural gas pipeline leaks that may find application measuring surface mine emissions as well. Physical Sciences Inc. (PSI) has developed a passive infrared imaging system which combines passive infrared concepts similar to FTIR with optical technology using an imaging sensor for remote detection of methane (Cosofret et al, 2004). The sensor consists of an infrared focal plane array-based camera and an interferometer. The interferometer functions as a filter which selects the wavelength illuminating the focal plane array. The sensor generates methane images and the methane column density at each pixel in the image is calculated using an algorithm. The algorithm incorporates range-to-target together with ambient conditions (temperature and humidity). Tests on this technology were done at 200m, but PSI note the system incorporates a wide field-of-view for wide area coverage. Perhaps further study could find application for this technology over larger areas for measurement of surface mine methane emissions.

3.4 Applying Technologies to U.S. Surface Coal Mines

After reviewing the SMM measurement methodologies, important elements of each study that could be combined to formulate a more robust methodology was found. The EPA measurement technique appears to underestimate the total emissions originating from the mine. It is unclear if the shooting of a single path using FTIR adequately represented methane emissions from all sources at the coal mine such as the high wall, mine floor, and overburden coals. The results were much lower than the gas contents of the coals, thus the duration in which the methane is released from the coal may be a factor not considered. In other words, the temporal accounting of methane released from the mine appeared not to consider methane emitting from the highwall for weeks or months leading up to the study. A more comprehensive (larger temporal and project boundary), perimeter-based, sample plan using updated equipment (i.e. Ophir) may produce a more representative methane emission rate. Furthermore, the use of numerical modeling techniques can provide information regarding the migration of methane from in-situ conditions to its eventual release to the atmosphere.

The CSIRO study focused more on gas content sampling protocols rather than the emission flux rate at the coal mines. The gas content data adjacent to a surface is of enormous value, but again, a more strategic sampling plan (100, 200, 500, 1000, 5000 meters from the face) would help facilitate more meaningful results. Procedures for measuring gas contents of coals are already well established in the CBM industry in the U.S., however, accounting for lost gas with high permeability coal (such as in the Powder River Basin) remains a source of high uncertainty.

In conclusion, the spatially-based gas content data should be measured and used in conjunction with an optical-based measurement of methane flux rates in order to develop a more representative measurement methodology for surface mine emissions. Since methane may be emitted for months (or years) ahead of mining, a numerical model should also be integrated in order to determine the temporal boundary of SMM emissions. Furthermore, since the ten largest surface mines in the PRB produce nearly 50 percent of the U.S. SMM emissions (discussed in more detail later in this report), a methodology geared to PRB mines and conditions is recommended.

4.0 Identification of Opportunities for Methane Recovery and Use at U.S. Surface Coal Mines

In addition to researching improvements to the U.S. surface mine methane emissions estimation methodology by collecting data about surface mine emissions and researching alternate methodologies, it was also desired to identify specific opportunities for methane recovery and use at U.S. surface coal mines. This was done by identifying the top emitting surface mines by utilizing the current methodology, and then conducting analysis of those mines in order to identify a specific set of mines where recovery may be feasible and warrant further evaluation. Methane recovery options were reviewed for specific mines and outstanding issues were identified such as mineral ownership or gas quality at the mines.

4.1 Sources of SMM Emissions

Based on the updated gas content data obtained and reported in **Section 2.3**, the new recommended basin-specific gas contents in **Table 2.2.1** were used to generate emission data for individual surface mines.

Analysis of annual coal production showed that of the 716 active surface mines in the U.S., the 330 most productive mines (mines with production greater than 100,000 tons per year) accounted for 98.56 percent of total production in 2003 (**Table 4.1.1**). Mine-specific emissions for coal mines that produced less than 100,000 tons per year were not calculated. It was concluded that due to the minute fraction of total production attributed to the remaining 386 mines, methane emissions from those mines are negligible. As a result, further analyses was concentrated on the top coal (and therefore emissions) producers.

Table 4.1.1 – Partitioning of Coal Production Data: U.S. Surface Coal Mines (as of 2003)

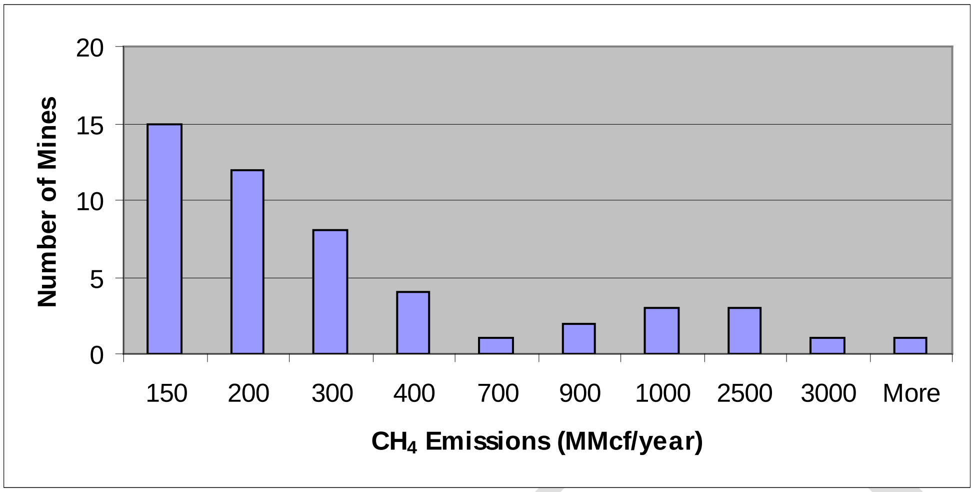
	Total Annual Coal Production (tons)	Percent of Total Production
Mines 1-330 (production greater than 100,000 tons/year)	707,554,754	98.56
Mines 331-716 (production less than 100,000 tons/year)	10,361,016	1.44
All Surface Mines	717,915,770	

Source: EIA, 2003

Emission data were obtained by multiplying the basin-specific gas contents in **Table 2.2.1** by the national emission factor of 200 percent (to account for over- and underlying strata), and then applying the result to the mines' annual coal production.

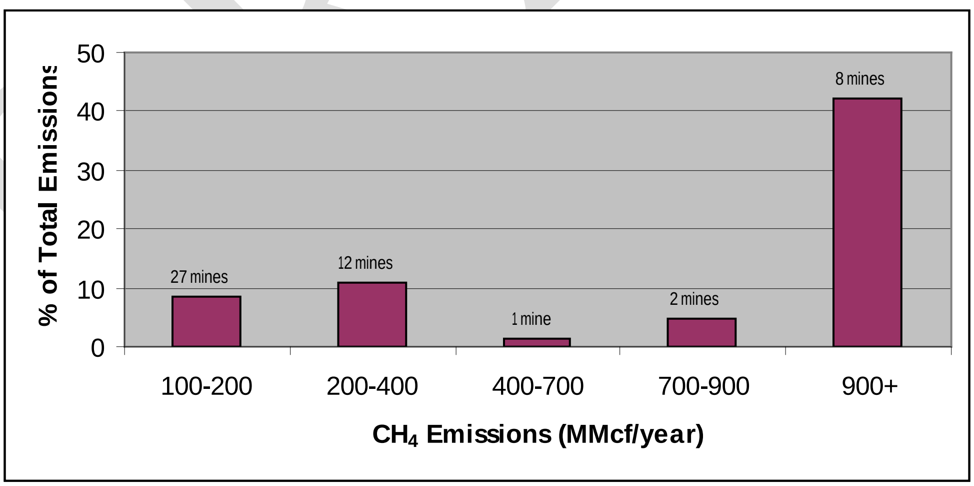
Underground mines with annual emissions greater than or equal to 100 MMcf/yr are considered gassy. The same consideration was applied for this analysis of surface mines. The 50 top-emitting surface mines in the U.S. had emissions greater than 100 MMcf/yr and accounted for 72.41 percent of total emissions. **Figure 4.1.1** shows how those 50 mines are distributed with regards to emissions. Approximately half of the 50 top-emitting mines produce 200 MMcf/yr or less.

Figure 4.1.1 – Frequency Distribution: 50 Gassiest Surface Coal Mines in the U.S. (as of 2003)[5]



The 100 mmcf/yr threshold for underground mines triggers MSHA-directed engineering controls and monitoring due to concern for miner safety. For diffuse emissions being emitted from surface mines, the same threshold for methane emissions would not necessarily apply since mine worker safety may not be threatened at those levels. Therefore a higher standard of "gassiness" may need to be considered for surface mines. **Figure 4.1.2** reveals that the high-emission mines account for the most significant percentage of emissions, though in **Figure 4.1.1** very few mines emitted more than 700 mmcf/year. For example, only 8 mines account for over 40 percent of total emissions, while 27 mines account for less than 10 percent of emissions.

Figure 4.1.2 – 50 Gassy Surface Coal Mines in the U.S.: Distribution of Percent of Total Emissions[6]



[5] Data used to develop this table was obtained during preparation of the annual Coal Mine Methane Emissions Inventory.

[6] Data used to develop this table was obtained during preparation of the annual Coal Mine Methane Emissions Inventory.

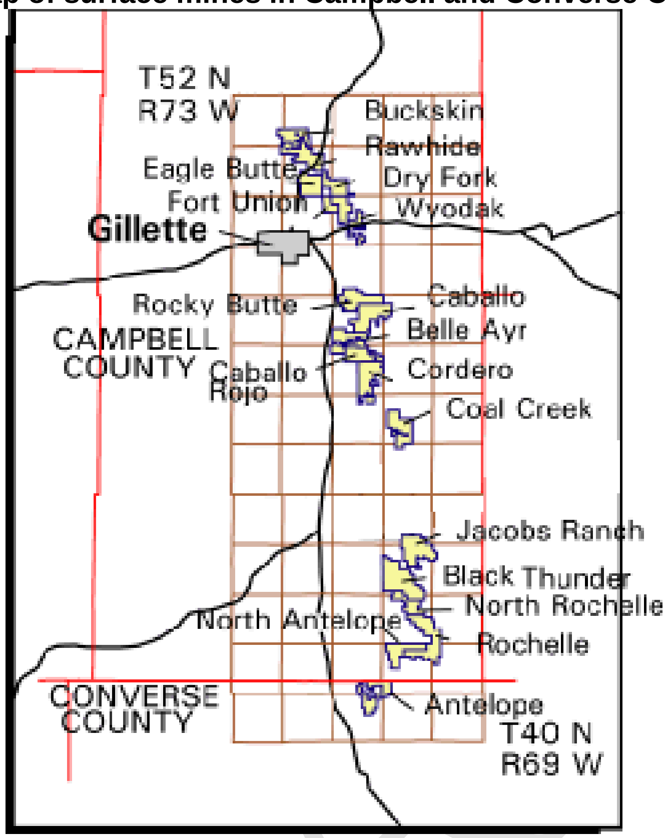
Of these 50 mines that account for approximately 72 percent of total SMM emissions, the top ten emitting surface mines in the U.S. (listed in **Table 4.1.2)** account for 46.9 percent of all surface mine emissions. The largest emitters, the North Antelope Rochelle Complex and Black Thunder Mines, located in Wyoming, are estimated to contribute 19 percent of total surface mine methane emissions alone. All of the mines listed in **Table 4.1.2** are located in Campbell County, Wyoming, except for the Antelope Coal Mine, which is located in nearby Converse County, Wyoming. Locations of the ten mines as well as others in the area are shown on the map in **Figure 4.1.3**. All are classified as being in the Northern Rockies Basin. The revised gas content recommended earlier in **Section 2.3** for the Northern Rockies Basin is 20 scf/ton.

Table 4.1.2 – Top Ten Emitting Surface Mines in U.S.[7]

Mine Name	2003 Production (tons)	Gas Content cf/ton	Emission Factor (cf/ton)	Emissions MMcf	Emissions Tonnes CO2e	Coal Basin	% of Total Emissions	Cumulative % of Emissions
North Antelope Rochelle Complex	80,083,444	20	40	3,203	1,295,750	NRB	10.71%	10.71%
Black Thunder Mine	62,620,417	20	40	2,505	1,013,198	NRB	8.38%	19.09%
Cordero Mine/Caballo Rojo Mine	36,083,743	20	40	1,443	583,835	NRB	4.83%	23.91%
Jacobs Ranch Mine	35,491,218	20	40	1,420	574,248	NRB	4.75%	28.66%
Antelope Coal Mine	29,533,072	20	40	1,181	477,845	NRB	3.95%	32.61%
Eagle Butte Mine	24,728,392	20	40	989	400,105	NRB	3.31%	35.92%
North Rochelle	23,923,145	20	40	957	387,076	NRB	3.20%	39.12%
Caballo Mine	22,743,284	20	40	910	367,986	NRB	3.04%	42.16%
Belle Ayr Mine	17,844,826	20	40	714	288,729	NRB	2.39%	44.55%
Buckskin Mine	17,539,156	20	40	702	283,784	NRB	2.35%	46.89%

[7] Data used to develop this table was obtained during preparation of the annual Coal Mine Methane Emissions Inventory.

Figure 4.1.3 – Map of surface mines in Campbell and Converse Counties, Wyoming



Source: Molnia et. al, 1997

4.2 Recovery

It was determined that the ten surface mines listed in **Table 4.1.2** emit enough methane to warrant further evaluation as potential methane recovery projects. These ten mines are at the eastern edge of the Powder River Basin (PRB) in Wyoming and account for nearly half of all surface mine methane emissions in the U.S. Since the 1990s, the PRB has been the focus of massive coalbed methane development efforts. Methane recovery at these mine sites would make a significant contribution towards mitigating methane emissions from surface mines.

The PRB has estimated methane reserves of 25 trillion cubic feet. The coalbed methane industry in the basin is flourishing as the number of producing wells has climbed to over 21,000 by the end of 2004, while in the mid-1990s, the basin had only 4,000 wells (Wilkinson 2005). With the methane industry thriving, coalbed methane development in the form of surface mine pre-drainage could make a sizeable contribution to methane recovery.

Realistically, the only feasible type of methane recovery to be deployed at surface mines is pre-mine drainage. Because of their proximity to existing CBM production wells, any pre-drainage wells placed in advance of the coal mining operations could be connected to an existing gas pipeline infrastructure. Many of the surface mines in the PRB require dewatering wells in advance of mining. It is also possible that some of the dewatering wells could be converted to methane production wells once the water table has been drawn down ahead of the highwall. Due to the high permeability of the PRB coals, only vertical CBM-type wells are feasible to use to degas coals ahead of mining, since nearly all of the gas within 2000 feet of the highwall has already been released.

Maps of the CBM fields adjacent to the largest surface mines in the Campbell County area were not available. A general map of CBM wells and mining operations in the PRB was located at the Wyoming State Geological Survey; however, it only provides information as recent as 2002. The map in **Figure 4.2.1** shows CBM wells as of 2002 and their proximity to the major coal mining operations in the PRB.

Active CBM wells are denoted by the black dots in the figure, which are located to the west of the coal mines. This map also shows some of the pipeline structure present in the area (denoted by red and yellow lines).

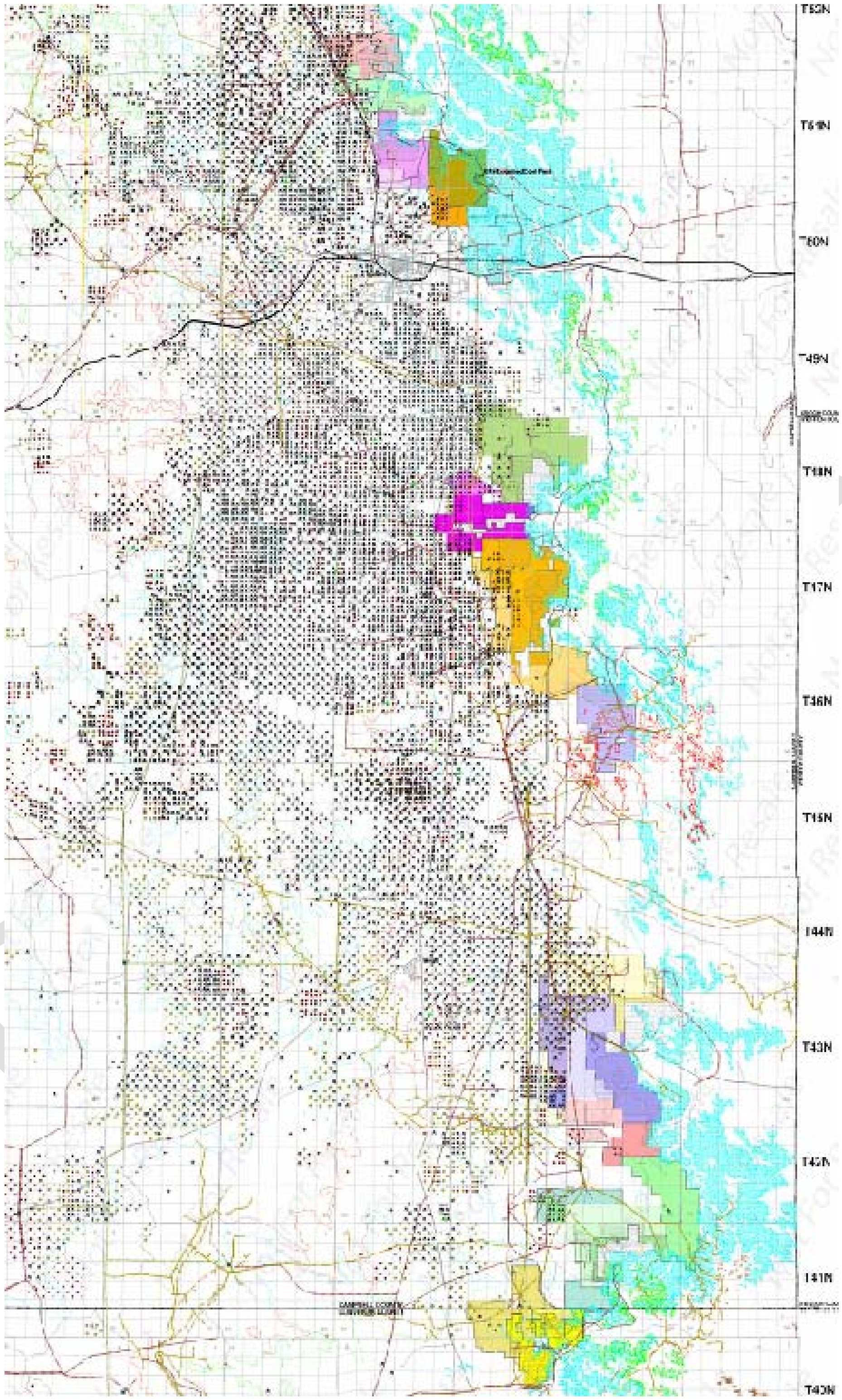
4.3 Outstanding Issues

The PRB has experienced a particularly dramatic increase in coalbed methane exploration and development. It contains the largest coal reserves of any basin in the United States. Over 90 percent of the Basin's coal estate is in Federal ownership and accounts for one-third of all U.S. coal production. About 45 percent of the oil and gas estate (including coalbed methane) in the PRB is under Federal ownership. Conflict has surrounded the development of CBM resources in the PRB in recent years (Fulton 2001).

A major clash has occurred between coal licensees and oil and gas developers. Commonly in the PRB, resource ownership is a “split estate” issue where the surface owner may not own the mineral rights below. Much of the mineral rights in the basin are owned by BLM and leased to private companies. Most federal oil and gas leases in the PRB are senior to coal licenses; however, at the time of overlapping licensure, extensive CBM development was not anticipated. In the past, traditional oil and gas and coal conflicts generally involved oil and gas resources contained in reservoirs much deeper than the coal, thereby allowing for development of coal without loss of the oil and gas development. Since CBM is trapped within the coal seams and was considered a valueless gas which escaped from coal, rather than part of the valuable coal fuel itself, coal companies routinely vented the gas to the atmosphere. Rising interest in CBM exploration and development as a result of new technology, a better understanding of the resource and increasing energy demand has created a mineral conflict situation concerning federal leases.

In 2001, the aforementioned conflict led to the introduction of federal legislation, HR 2952, the Powder River Basin Resource Development Act, sponsored by Representative Barbara Cubin (R –WY), which would have permitted the suspension of CBM operations in order to allow coal production to continue while providing a means for the oil and gas lessee to be paid equitable compensation. However, Congress did not enact this legislation and it did not become law. BLM’s current conflict resolution procedure involves ordering CBM drilling sooner than planned if it might otherwise be vented during mining in order to avoid the waste of this resource.

Figure 4.2.1 - Map of Powder River Basin Mines and CBM Wells



Source: (WSGS, 2002)

Recently, environmental concerns have arisen regarding CBM production. A significant consideration in any coalbed methane extraction project is the issue of by-product water produced from the CBM wells. CBM operators now face added cost due to bonding requirements for in-channel reservoirs used to hold water produced from their wells, as the Wyoming BLM has extended bonding requirements to federal minerals. Operators have previously only been required to post reclamation bonds for reservoirs on state and private lands. Bonds may be $5,000 to $10,000 or more (depending on the nature of the site) and are designed to protect the land from any known or unforeseen risks related to displacement of millions of barrels of water onto the surface by providing funds for mitigation of detriments that may occur later on. Efforts are also in progress to extend bond requirements to cover downstream impacts to vegetation and soils. The added requirements pose significant added costs to CBM operations in Wyoming (Bleizeffer, 2005a).

Another obstacle to CBM development in the PRB is a decision by the 10th Circuit Court of Appeals which halted all leasing of federal gas in August 2004. The decision ruled that the BLM had not addressed the effects of CBM development in earlier environmental impact statements on which the decision to allow CBM leases was based. Also, BLM had not considered the option of not issuing questionable leases. The court ruled that BLM must conduct an Environmental Assessment (EA) specific to issues with coalbed methane extraction which were not originally considered (e.g. by-product water) and consider not issuing leases. Until completion of this EA, leasing of federal gas rights is on hold. However, the methane industry already holds lease rights to 95 percent of federal land in the PRB, with about 3,000 new wells being drilled annually (Bleizeffer, 2005b).

4.4 Recommendations

In analyses of mine-specific surface mine methane emissions in the U.S., it has been determined that emissions from the mines of the PRB are most significant and may warrant further evaluation as candidates for methane recovery. The ten highest emitting mines in the PRB account for nearly half of all surface mine methane emissions in the U.S. and could be considered for pre-drainage projects with connection to existing pipeline infrastructure.

CBM development in this area is flourishing at present; however, any methane development in this area will be subject to stipulations brought about by the conflicting gas ownership issues, as well as consideration for environmental issues especially by-product water disposal. Even with obstacles, continued CBM development in the PRB will result in an estimated 40,000 new wells being drilled over the next decade (Jackson, 2003).

5.0 Summary and Conclusions

Research was conducted in order to assess and improve the current U.S. surface mine methane emissions inventory. Improvements were made to the SMM emissions inventory in 2003, with the compilation of additional gas content data that led to the use of more representative gas content values for several coal basins (**Table 2.0.1**). To further this improvement, geological research was performed, providing information leading to further distinction among the gassy coal basins and additional revisions to gas content values used in emission calculations (**Table 2.2.1**). Research was also conducted on overburden and coal seam thicknesses occurring at surface mines as a basis for assessing the current emission factor of 200 percent used for calculating SMM emissions in the U.S. Comparison of adjacent seams and strata to the mineable seam has yielded the conclusion that the current 200 percent emission factor is likely too large, and a factor of 150 percent may be more appropriate. The current post-mining emission factor was assessed, and it was concluded that without additional data there is no reason for it to be changed. The newly proposed coal basin gas content values and revised basin distinctions were applied, as well as the suggested emission factor for comparison with the previous values used. When the new gas contents were applied without the suggested emission factor, a net increase of 7.5 Bcf was calculated.

It was concluded from the study of international gas contents that the values being used in the U.S. methodology fall within a reasonable range of international values, and in some instances are somewhat lower than the worldwide average (**Figure 2.6.2**).

In order to assess potential improvements to the current methodology and explore methods closer to Tier 3, research was conducted on several technologies and methods proposed for measurement of surface mine emissions. It was concluded from literature research that the spatially-based gas content data should be collected and used in conjunction with an optical-based measurement of methane flux rates in order to develop a more representative measurement methodology for surface mine emissions.

Finally, the SMM emissions estimation methodology was applied to the highest producing (more than 100,000 tons/year) surface mines in the U.S., and the gassiest mines which could be considered for methane recovery were identified. These mines of interest are in the Powder River Basin. Though there are several outstanding issues with gas projects in this region, CBM development is flourishing and recovery looks promising.

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