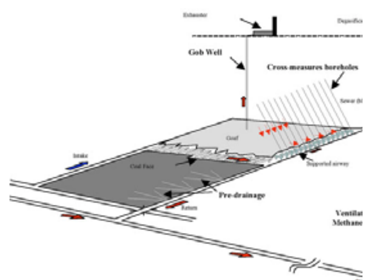
DEVELOPMENT OF A COMMON PRACTICE STANDARD FOR A COAL MINE METHANE PROJECT PROTOCOL



A Research Paper for the:
Climate Action Reserve

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SAIC

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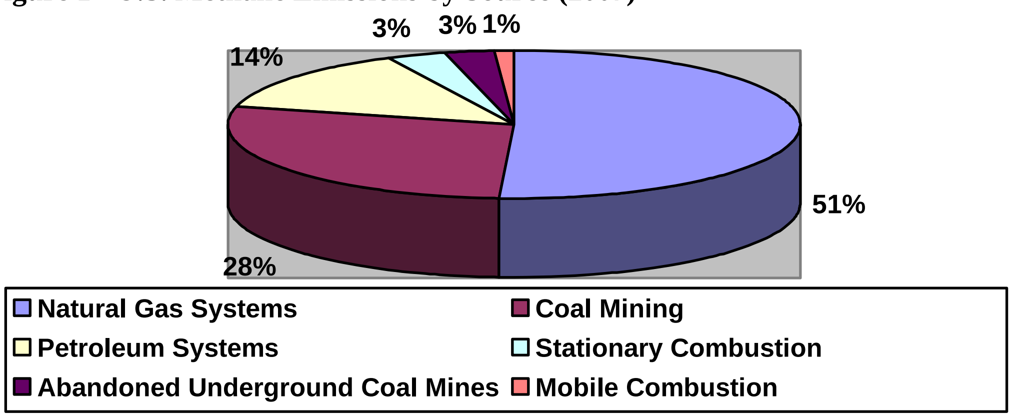
1. BACKGROUND DISCUSSION OF COAL MINE METHANE EMISSIONS

The U.S. coal mining industry is a significant source of methane, a potent greenhouse gas (GHG). Methane is formed during the same geologic process that converts vegetative matter to coal; the mining and post-mining processes release this methane from the coal and surrounding rock to the atmosphere. According to the U.S. Environmental Protection Agency's (EPA) draft 2007 U.S. GHG inventory,[1] the coal industry accounted for 2.744 million metric tonnes of methane emissions in 2007, or 28.0 percent of total U.S. methane emissions. As Figure 1 indicates, the coal industry is second in magnitude only to natural gas systems as a source of methane emissions. On a CO_2-equivalent basis, the coal industry accounted for 57.6 terragrams of methane emissions in 2007, representing 0.8 percent of total U.S. emissions of GHGs.

Abandoned underground coal mines accounted for an additional 0.273 million metric tonnes of methane in 2007, representing 2.8 percent of total U.S. methane emissions and 0.1 percent of total U.S. GHG emissions (on a CO_2-equivalent basis).

Excluding abandoned mines, there are a number of active sources of methane within the coal industry, including underground mines, surface mines, and post-mining sources (including coal preparation and storage facilities as well as the coal transportation process). As Figure 2 indicates, underground mines are the primary emissions source, accounting for 61.6 percent of the coal industry's total methane emissions. The amount of methane contained in and around a coal seam tends to be correlated with the amount of geologic pressure on the seam, which in turn depends on seam depth; shallow seams that can be mined using surface techniques tend to be less gassy than deeper seams accessible only through underground mining.

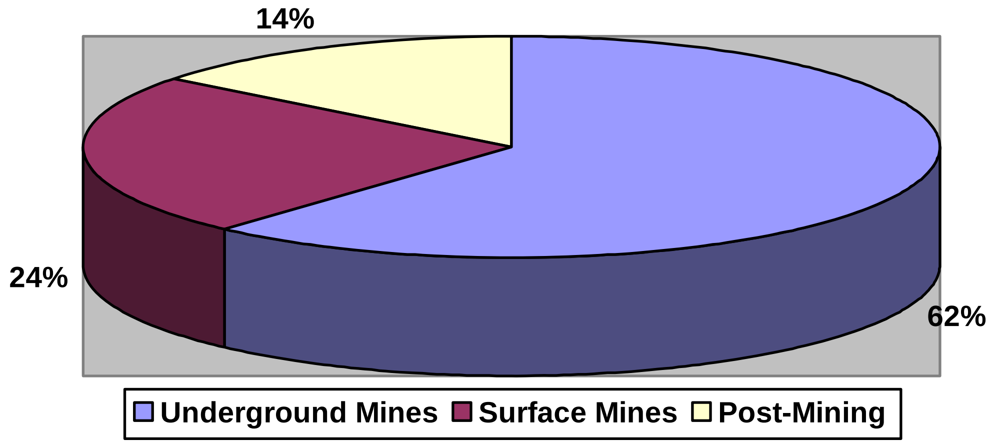
Figure 1 - U.S. Methane Emissions by Source (2007)



Source: Based on data in U.S. EPA, *Draft Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007*, Feb. 2009, p. 3-2.

[1] U.S. EPA, *Draft Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007*, Feb. 2009.

Figure 2 - U.S. Coal Industry Methane Emissions by Source (2007)



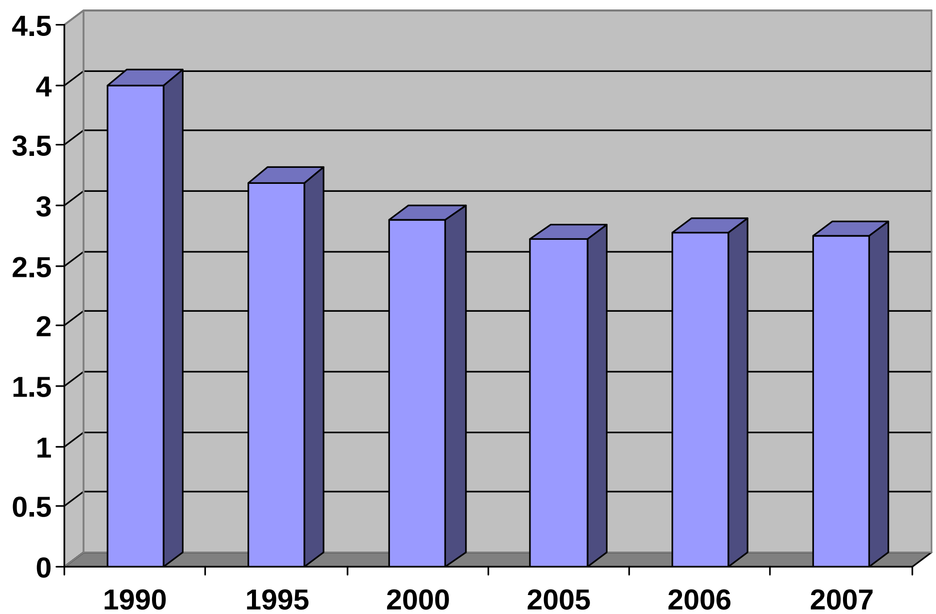
Source: Based on data in U.S. EPA, *Draft Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007*, Feb. 2009, p. 3-37.

1.1 Trends

Coal industry methane emissions have declined over time, from 4.003 million metric tonnes in 1990 to 2.744 million metric tonnes in 2007 (a 31.5 percent decline—see Figure 3). This decline occurred despite an increase in total U.S. coal production, from 0.931 billion metric tonnes in 1990 to 1.039 billion metric tonnes in 2007 (an 11.6 percent increase). However, while total production increased, production from underground mines declined as the industry continued its long-term historic shift from underground mining to large-scale surface mining (see Figure 4). Because surface mines emit less methane than underground mines, this technological shift was accompanied by a reduction in methane emissions.

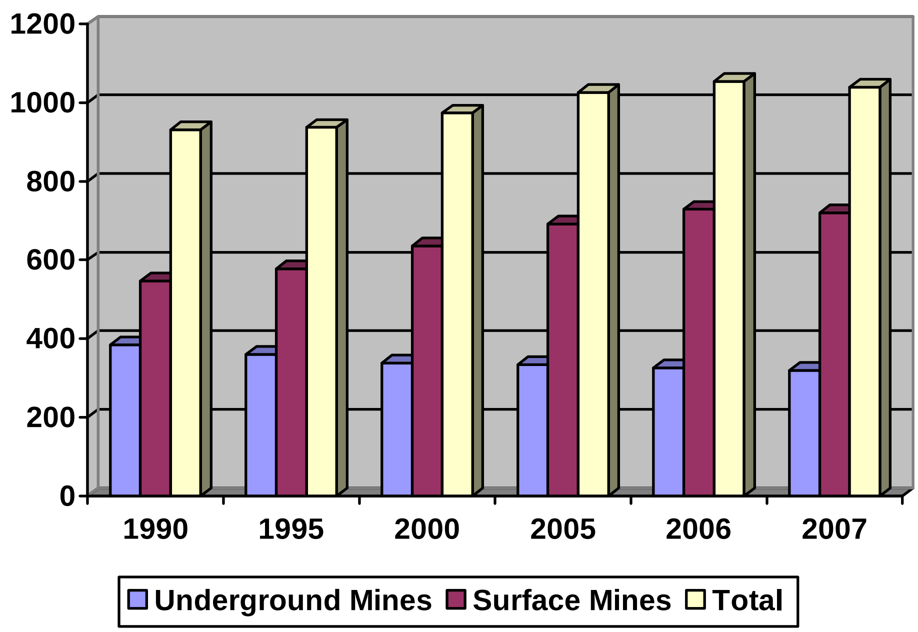
However, the shift towards surface mining is not the sole factor driving the declining trend in methane emissions. Figure 5 indicates that, both for surface mines and underground mines, methane emissions per tonne of coal mined are steadily declining. The trend for underground mines is particularly pronounced—underground mining methane emissions have dropped from 7.73 kilograms per tonne of coal mined in 1990 to 5.29 kilograms per tonne in 2007. This significant reduction in emissions intensity is due, in part, to a major increase in the amount of methane captured and used or sold by underground operations. In 1990, total underground mine emissions were reduced by 0.266 million metric tonnes—representing 8.2 percent of what they otherwise would have been—through the capture and use of a portion of the liberated methane. By 2007, total methane captured and used had more than doubled from the 1990 level, to 0.584 million metric tonnes (representing 25.7 percent of the total amount of methane emitted and captured/used). However, as Figure 6 shows, the total quantity of methane captured and used actually declined significantly in 2007 relative to 2006. Assuming 2007 is an anomaly in the longer-term upward trend in the quantity of methane captured/used, we might expect 2008 capture/use quantities to be approximately triple the levels seen back in 1990.

Figure 3 - Total Coal Industry Methane Emissions (Million Metric Tonnes), 1990-07



Source: Based on data in U.S. EPA, *Draft Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007*, Feb. 2009, p. 3-2.

Figure 4 - U.S. Coal Production by Mine Type (Million Metric Tonnes), 1990-07



Source: Based on data in U.S. EPA, *Draft Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007*, Feb. 2009, p. 3-38.

Figure 5 - Methane Emissions (in kilograms) per Tonne of Coal Produced, 1990-07

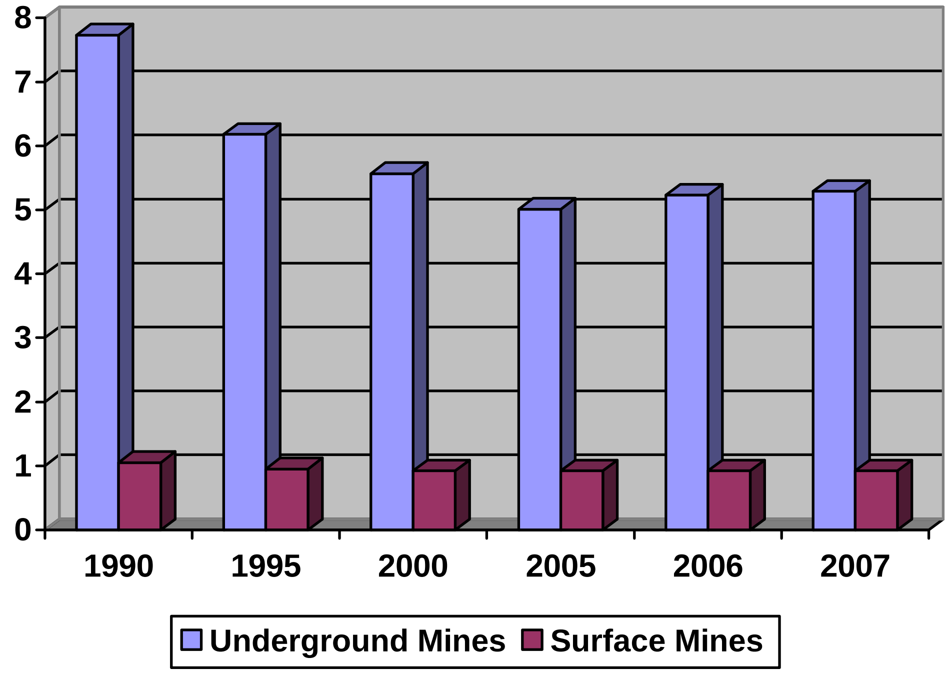
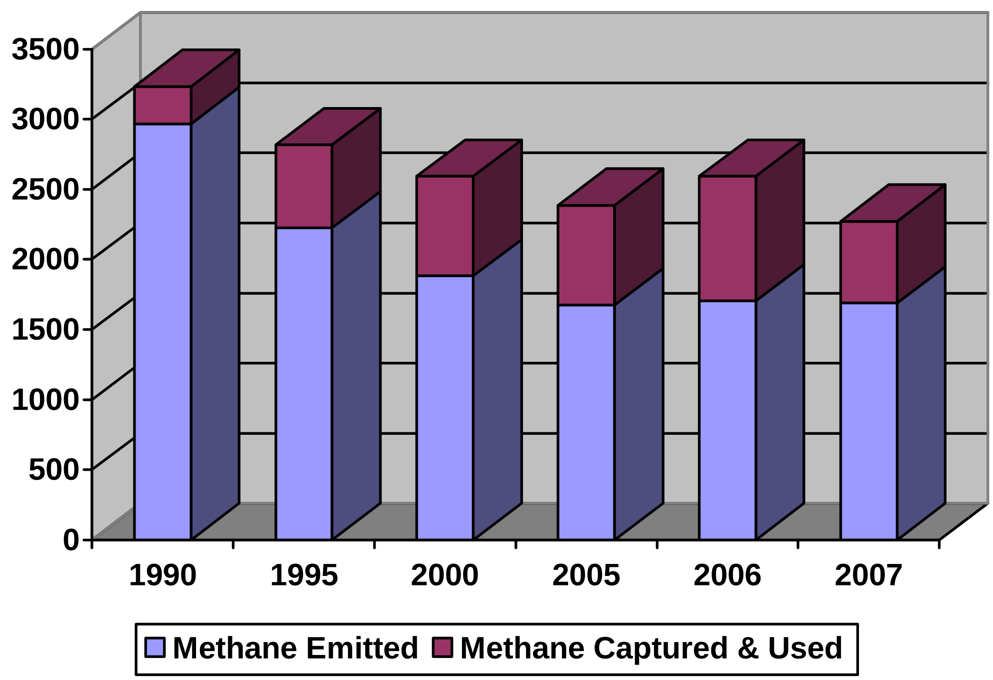


Figure 6 - Total Underground Mine Methane Emissions vs. Methane Captured and Used, 1990-07



Sources for Figures 5 and 6: Based on data in U.S. EPA, *Draft Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007*, Feb. 2009, p. 3-37, 3-38.

1.2 Regional Variations in Methane Emissions

Table 1 presents 2007 coal mine methane emissions by region and state, along with corresponding coal production, percentage of production from underground mines, and emissions per ton of coal produced. As this table shows, the majority of the nation's coal mine methane emissions (62.3 percent of the total) originate in Appalachia. This is not surprising, given that underground mining still predominates in this region of the country. The major coal producing states of West Virginia, Kentucky, and Pennsylvania are all significant contributors to Appalachia's total emissions. These three states account for 82.2 percent of the region's production, and 65.9 percent of its methane emissions. However, it is interesting to note that Kentucky's average emissions intensity is significantly less than the Appalachian average (80 cubic feet per ton vs. 215 cubic feet per ton). This reflects the fact that a relatively large proportion of the underground mines in eastern Kentucky are relatively shallow drift mines—i.e., mines that are accessed via horizontal drift entries rather than vertical shafts). In contrast, Alabama, which currently hosts some of the deepest underground mines in the country, is characterized by an emissions intensity four times the Appalachian average, and seven times the national average. These variations in emissions intensity, reflecting in turn geographic variations in coal seam depth, help to explain why a large proportion of the underground mines in Alabama utilize advanced methane degasification and capture/utilization techniques, while such techniques are uncommon in Kentucky. In general, the best opportunities for methane capture and utilization projects will exist in those regions and states characterized by deep coal seams and high emissions intensities.

The interior region accounts for only 8 percent of the coal industry's total methane emissions, with most of these emissions concentrated in the Illinois Basin states of Illinois and Indiana. This reflects the fact that these two states account for over 98 percent of the Interior's underground coal production.

The western region accounts for 29.7 percent of U.S. coal mine methane emissions. The West, and especially the Powder River Basin of northeastern Wyoming and southeastern Montana, is characterized by massive surface mines. Wyoming alone accounts for 73.0 percent of the region's total production. Even though nearly all of this production is from surface mines, the sheer quantity of coal being produced in Wyoming makes the state second only to West Virginia in total methane emissions. Unfortunately commercially viable opportunities for reducing these surface mining emissions are not available. In the West, such opportunities are limited to the major underground mining states of Colorado, Utah, and New Mexico. Colorado's underground mines are particularly significant emitters of methane, accounting for 64.8 percent of the total emissions from the three significant underground mining states. Colorado's average emissions intensity is also significantly greater (two to three times greater) than the emissions intensities of Utah and New Mexico.

Table 1 - Methane Emissions and Coal Production by Region and State (2007)

Region/State	Total CH_4 Emissions (Million Cubic Feet)	Total Coal Production (Thousand Short Tons)	Percent of Production from Underground Mines	CH_4 Emissions Intensity (Cubic Feet/Ton of Coal Produced)
Alabama	16,580	19,327	59.3	858
Kentucky	9,278	115,280	60.0	80
Maryland	261	2,301	26.6	113
Ohio	2,672	22,575	70.8	118
Pennsylvania	19,472	65,048	82.3	299
Tennessee	120	2,654	33.6	45
Virginia	10,118	25,346	62.1	399
West Virginia	28,797	153,480	55.3	188
Appalachia	**87,298**	**406,011**	**62.1**	**215**
Arkansas	144	83	96.4	1,735
Illinois	4,493	32,445	82.6	138
Indiana	4,347	35,003	30.3	124
Kansas	33	420	0.0	79
Louisiana	80	3,127	0.0	25
Mississippi	253	3,545	0.0	71
Missouri	19	236	0.0	81
Oklahoma	774	1,648	31.2	470
Texas	1,073	41,948	0.0	26
Interior	**11,216**	**118,455**	**32.1**	**95**
Alaska	49	1,324	0.0	37
Arizona	135	7,983	0.0	17
Colorado	11,671	36,384	75.9	321
Montana	2,016	43,390	0.1	46
New Mexico	2,660	24,451	28.2	109
North Dakota	385	29,606	0.0	13
Utah	3,678	24,307	100.0	151
Wyoming	20,974	453,568	0.6	46
West	**41,568**	**621,013**	**9.9**	**67**
U.S.	**140,082**	**1,145,479**	**30.7**	**122**

Sources: Based on data in U.S. EPA, *Draft Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007*, Feb. 2009, p. A-126, and U.S. Energy Information Administration, www.eia.doe.gov/cneaf/coal/page/acr/table1.html.

1.3 Underground Coal Mine Degasification

Methane emissions from underground coal mines are often referred to, erroneously, as fugitive emissions. In fact, although methane emissions from surface mines and post-mining activities are properly described as fugitive, underground mine methane emissions do not fit either formal technical definitions of fugitive emissions (e.g., “*uncontrolled* emissions that do *not* occur through an exhaust pipe, chimney, vent or other functionally equivalent opening”[2]) nor the common connotation of the word “fugitive” (which, when applied to methane, suggests that the gas is inadvertently escaping—rather than being actively and deliberately removed—from the mine). On the contrary, as degasification is an integral, critically important component of the underground mining process, methane emissions are *process* emissions, vented through mine ventilation shafts or methane drainage wells designed for the express purpose of removing the methane from the mine. In fact, the physical layout of the mine is often dictated, in part, by degasification requirements, and significant capital and operating expenses are incurred by the mine operator to actively remove the methane from the mine and vent it to the atmosphere. These expenses are necessitated by safety considerations. When combined with air in concentrations of 5 to 15 percent, methane is an explosive gas. Mine operators must keep the concentration of methane in the mine air well below the 5-percent level at which it becomes hazardous. Two primary techniques are available to the operator to achieve this goal: ventilation and methane drainage.

1.3.1 Mine Ventilation

Ventilation is the traditional technique. *All* underground coal mines in the U.S. are required to establish and maintain ventilation systems meeting detailed specifications set forth in federal regulations; these regulations are enforced by the Mine Safety and Health Administration (MSHA). The primary purpose of these ventilation systems is to (1) dilute the methane in the mine air, and (2) remove the methane from the mine. Under the MSHA regulations, methane concentrations must be kept below 1 percent at the working face. This is accomplished by ensuring that an adequate quantity of clean air is delivered to the face (3,000 cubic feet per minute at a minimum, according to the MSHA regulations). Clean intake air is drawn into the mine from the atmosphere through intake air shafts and/or horizontal drift entries, where it is channeled through the intake airways to the face, and then through the “returns” to a return air shaft(s) and/or drift entry(ies). The energy needed to move the large quantities of air required under the MSHA regulations through the ventilation system is provided by high-powered exhaust mine fans located on the surface at the return air shaft(s). Upon passing up the return air shaft(s) and through the fan, the mine air, including diluted methane, is vented to the atmosphere. While intake air shafts typically serve the multiple purposes of providing access to the mine for personnel, equipment and supplies, return air shafts are designed exclusively to vent the return air to the atmosphere.[3] A single mine may have more than one return air shaft and/or drift entry, depending on ventilation system requirements and the physical extent of the mine, but will always have at least one. Each return air shaft constitutes a single methane emissions source. Partly because the methane emitted from mine ventilation systems is highly dilute (typically less than 1 percent of the return air), technologies designed to capture and utilize this methane are not in commercial use in the U.S. at present (although a new ventilation air methane, or VAM, demonstration project has recently been commissioned at one U.S. coal mine). The same is not, however, the case for the second main degasification technique—methane drainage.

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[2] The Climate Registry, *General Reporting Protocol*, March 2008, p. 155.

[3] Although return air shafts may also serve as secondary escape routes in the event of a mine explosion or other catastrophe.

1.3.2 Methane Drainage

As noted above, mine ventilation is the traditional coal mine degasification technique, and in the vast majority of cases it suffices to meet the MSHA requirements for diluting and removing methane from the mine. However, for some mines operating in very gassy conditions, ventilation alone may not suffice to meet MSHA requirements in an economically viable manner. Specifically, under very gassy conditions, the costs associated with sinking more and/or larger diameter return air shafts and developing more main entries to handle the larger air quantities required to dilute the methane may become prohibitive, as may mine fan capital costs and power requirements. In addition, with increased gassiness significant lost revenue may occur due to production delays resulting from the automatic shut off of mining equipment (which occurs whenever methane concentration exceeds allowable limits at the face). Hence at very gassy mines, ventilation is typically supplemented with methane drainage systems designed to remove methane either in advance of, or behind, the working face. These systems involve drilling boreholes, either from the surface or inside the mine, to drain methane from the coal seam, surrounding strata, or underground workings, thereby reducing the amount of methane that has to be handled by the ventilation system along with ventilation-related mining costs.

There are three main types of drainage systems, which may be employed in isolation or in combination with one another:

- Vertical pre-mining boreholes;
- Horizontal pre-mining boreholes; and
- Post-mining (gob) boreholes.

Each of these three system types are described in more detail below.

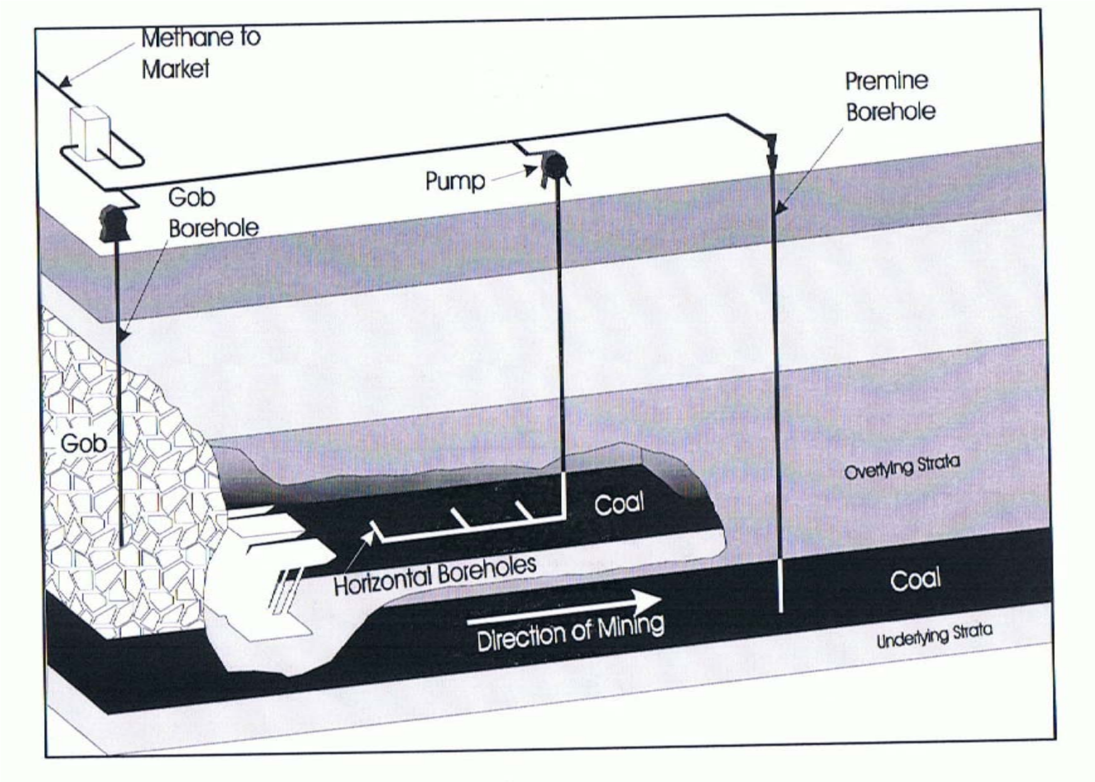
Vertical Pre-Mining Boreholes

Vertical pre-mining boreholes, or wells, are drilled vertically from the surface to unmined portions of the coal seam in advance of mining (see Figure 7). They recover methane both from the seam itself, as well as from strata lying above the seam. Vertical pre-mining wells may be drilled in locations that are not scheduled to be mined through for months or years; sometimes vertical pre-mining wells are drilled before the associated mine even opens. Because they are drilled into virgin coal instead of the underground workings, pre-mining vertical wells produce a high quality gas that is uncontaminated with mine air. Typically gas from these wells is at least 90 percent pure methane.

The amount of methane that is recoverable using vertical pre-mining wells varies depending on site specific conditions such as the permeability of the coal seam, as well as the number of years the wells remain in operation before they are mined through.

According to EPA, recovery rates of 50 to 70 percent of the methane that would otherwise have been emitted are likely for wells drilled 10 years in advance of mining.[4]

Figure 7 - Schematic of Vertical Pre-Mining, Horizontal Pre-Mining, and Gob Boreholes



Source: U.S. EPA, *Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 2002-2006*, EPA-430-K-04-003, Sept. 2008, p. 2-5.

Horizontal Pre-Mining Wells

Horizontal pre-mining boreholes, also referred to as in-mine boreholes, are drilled from within the mine (rather than from the surface) into unmined blocks of coal (see Figure 7). They are generally 400 to 800 feet in length, and are drilled shortly (as opposed to years) before mining occurs. Methane is drained from the boreholes by an in-mine vacuum piping system, which transports the methane to the surface where it may be either vented or captured and utilized. Because horizontal boreholes are drilled directly into the coal seam from the mine, drainage is limited to the methane contained within the seam; methane in the surrounding strata is unaffected. Hence recovery rates tend to be low (10 to 18 percent of the methane that would otherwise have been emitted from the ventilation system), although the gas recovered from horizontal boreholes is generally comparable in purity to methane drained from vertical pre-mining boreholes.[5]

[4] U.S. EPA, *Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 2002-2006*, EPA 430-K-04-003, September 2008, p. 2-4.
[5] U.S. EPA, *Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 2002-2006*, EPA 430-K-04-003, September 2008, p. 2-6.

Post-Mining Boreholes

Post-mining, or gob, boreholes are drilled from the surface to a point 10 to 50 feet above the coal seam in advance of mining (see Figure 7). As mining advances under and past the well, the strata above the coal seam fractures and eventually collapses into the mined out area creating a de-pressurized zone extending up to the well; this zone is called the gob. Methane and other gasses from the gob are recovered via the gob well. It should be stressed that the gob is exposed to the mine air, and hence the methane drained by gob wells is typically less pure than gas recovered by pre-mining boreholes. In many cases vacuum pumps are used in conjunction with gob wells to enhance gas recovery and to prevent methane from entering the mine's ventilation circuit. However, these pumps may draw in mine air as well as methane, thus exacerbating the contamination of the recovered methane. Gob gas typically has a heating value ranging from 300 to 800 Btus per cubic feet (as compared with approximately 1000 Btus per cubic foot for pipeline quality natural gas). This said, a number of coal companies are upgrading gob well gas to produce a product meeting the quality specifications of pipeline companies. Depending on their number and spacing, gob wells can recover 30 to 50 percent of the methane that would otherwise be emitted.[6]

1.3.3 Prevalence of the Different Degasification Techniques

With the preceding discussion serving as background, we can now begin to consider the prevalence of, and emissions associated with, the different degasification system types as a prelude to the development of common practice standards. In 2007, there were 728 underground coal mines in operation in the United States.[7] As already noted, *all* of these underground coal mines are required by MSHA to maintain ventilation systems. In contrast, the use of drainage systems is relatively uncommon. Based on data provided to SAIC by EPA,[8] 20 mines had operating drainage systems in place in 2007. All 20 of these mines are classified as "gassy" by MSHA, meaning that they have methane liberation rates of at least 100,000 cubic feet per day. A total of 131 mines met this threshold in 2007; hence even among gassy mines drainage system usage is uncommon. As we shall see, only the very gassy mines, with methane liberation rates in excess of 1 million cubic feet per day, utilize methane drainage. This indicates that ventilation systems alone are capable of meeting MSHA requirements for all but the gassiest mines. However, for these latter mines it appears that the costs of relying exclusively on ventilation begins to approach and, as methane liberation rates rise, exceed the costs of installing a drainage system.

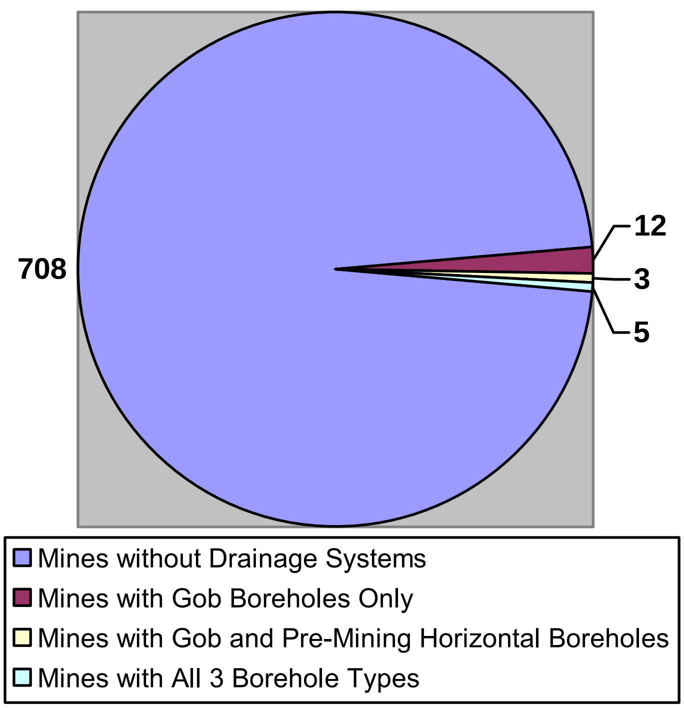
All 20 of the mines with drainage systems utilized gob boreholes in 2007.[9] In addition, 8 of these mines utilized pre-mining boreholes. Of these 8 mines, 5 used vertical pre-

[6] Ibid., p. 2-5.
[7] U.S. Energy Information Administration, www.eia.doe.gov/cneaf/coal/page/acr/table1.html.
[8] Coal 07 draft.xls file.
[9] It should be noted that, in addition to the standard vertical gob boreholes, the EPA data indicate that two of the mines use horizontal gob boreholes. Although additional information on these boreholes is lacking,

mining wells and all 8 used horizontal boreholes (see Figure 8). As shall be seen, pre-mining degasification is generally reserved for mines operating in extremely gassy conditions.

Fifteen of the 20 mines with drainage boreholes capture and utilize all or a portion of the drained methane. In 2007 13 of these 15 mines sold the captured methane to natural gas pipeline companies (see Figure 9). One mine used the captured methane to generate electricity, and one mine heated its ventilation air using the captured methane. In addition, one of the mines that sells gas to a pipeline uses additional gas to fire a thermal coal dryer at its prep plant.

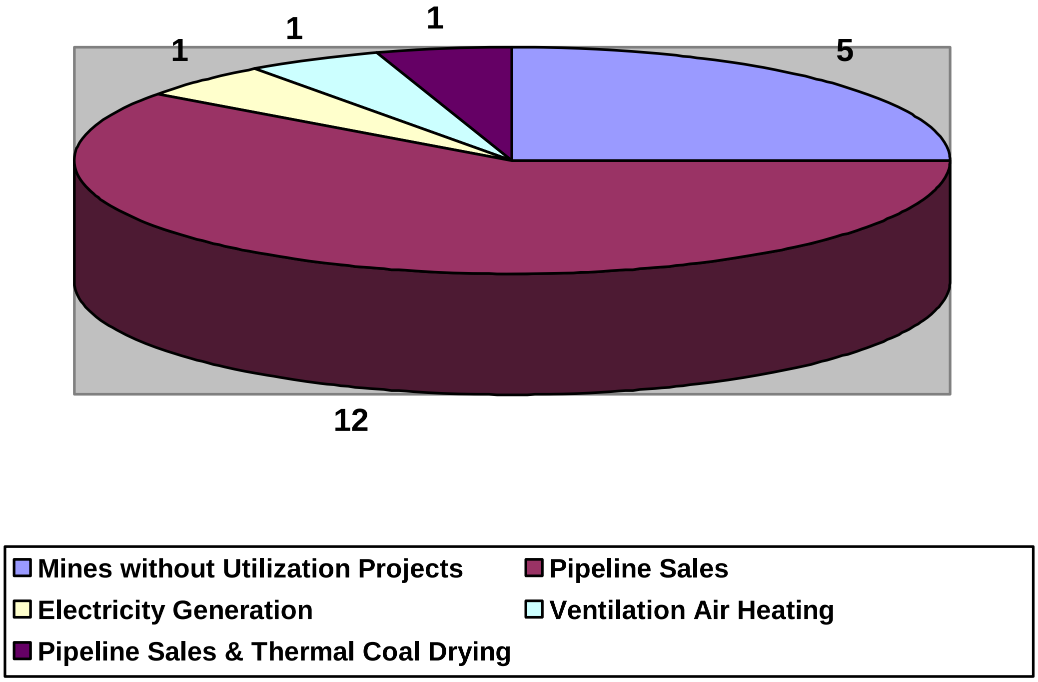
Figure 8 - Mines by Type of Drainage System Used, 2007



Source: EPA, Coal 07 draft.xls file.

presumably the two mines in question (both of which are longwall mines) are drilling into mined out longwall panels from adjacent panels, through the barrier pillars left between panels.

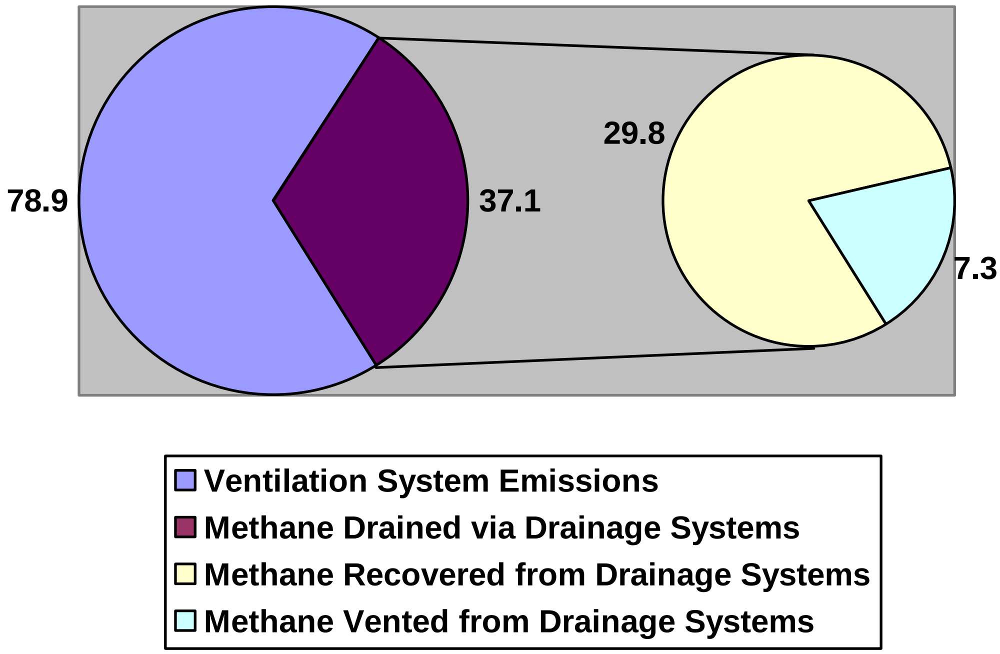
Figure 9 - Mines with Drainage Systems by Type of Methane Utilization Project, 2007



Source: EPA, Coal 07 draft.xls file.

Although methane drainage is a relatively uncommon practice, the total quantity of methane being drained from U.S. coal mines is nonetheless significant. This reflects the fact that the few mines that *do* utilize drainage are among the gassiest; these mines account for a disproportionate share of total underground mine methane emissions. In 2007, the total quantity of methane drained through drainage systems was 37.1 million cubic feet, or 32 percent of the total amount of methane liberated from underground coal mines (*prior* to any capture and use of this methane). It is important to note that most of this drained methane was recovered and used. Only 7.3 million cubic feet of methane (19.9 percent of the total drained) was vented from drainage systems in 2007; the remaining 29.8 million cubic feet was put to productive use (see Figure 10). Venting from drainage systems accounted for only 8.5 percent of total underground mine methane emissions; the remaining 91.5 percent (78.9 million cubic feet) was vented by mine ventilation systems.

Figure 10 - Ventilation and Drainage System Emissions, 2007 (Million Cubic Feet)



Sources: Developed by combining data in U.S. EPA, *Draft Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007*, Feb. 2009, p. 3-37, with data in EPA's Coal 07 draft.xls file.

The EPA database does not distinguish separate drainage, recovery, and emissions data by drainage system type. However, using the available data we can separate the total amount of methane drained in 2007 into the following three categories:

- Methane drained from the 12 mines using gob wells only: 7.7 million cubic feet (20.8 percent of the total drained);
- Methane drained from the 3 mines using gob wells and pre-mining horizontal boreholes: 3.4 million cubic feet (9.2 percent of the total drained);
- Methane drained from the 5 mines using gob wells, pre-mining horizontal boreholes, and pre-mining vertical boreholes: 26.0 million cubic feet (70.0 percent of the total drained).

As these data indicate, the small group of mines using all three drainage techniques account for the majority of methane drained from U.S. coal mines. This, in part, reflects the fact that the amount of methane recovered will increase as more recovery techniques are utilized. However, as we shall see, the mines using all three recovery techniques are also much gassier than the mines relying on only one or two techniques. Hence the former mines are draining more methane in part simply because these mines have more methane available for recovery through drainage. Furthermore, it is likely that the extremely gassy conditions characterizing these mines either necessitates the use of all available drainage techniques to ensure that the ventilation system provides adequate dilution of methane within the mine, or at least improves the economics associated with the combined deployment of all three techniques.

Historical Data Analysis

Table 2 shows historical trends in the number of mines using drainage techniques and capture/utilization. A number of salient points can be drawn from this table. First, the number of mines using drainage has declined, from 33 in 1990 to 20 in 2007. However, to put this decline in perspective, it is important to note that the total number of mines (both underground and surface) has also dropped over this same period, from 3,355 to 1,374 (a 59 percent decline). Since 2000, the number of mines practicing drainage has remained relatively stable, at approximately 20. The breakdown of these mines by type of drainage system used has also remained fairly stable, with gob drainage used at all of the mines, supplemented with horizontal pre-mining boreholes at 3 operations and both horizontal and vertical pre-mining boreholes at 5 to 7 mines.

More importantly from an environmental standpoint, the number of mines capturing and utilizing methane has more than doubled since 1990, from 7 to 15. Most of this growth occurred between 1990 and 1995, although the year 2005 saw a sharp increase in the number of projects from 12 to 15. Throughout the 1990-07 time period, virtually all of the mines that practiced methane capture sold the recovered gas to pipeline companies. Only four other capture and utilization projects are identified in the database—two electricity generation projects (one of which is combined with a pipeline sales project at one of the mines), a project that utilizes captured methane to heat mine ventilation air, and a project that applies gas in excess of the amount sold to a pipeline to the thermal drying of coal at a prep plant.

Table 3 shows the historical trends in ventilation system emissions, drainage system emissions, and methane capture/use from drainage systems over the 1990-07 time period. As the table indicates, emissions from ventilation systems declined significantly (33.2 percent) from 1990 to 2005, reflecting the long-term historic shift from underground to surface mining. Between 2005 and 2007, as underground mining production leveled off, ventilation system emissions increased slightly. During this same time there was a drop in both the number of mines operating drainage systems (from 24 to 20, see Table 2) and in the amount of methane handled by these systems, suggesting a shift towards greater reliance on ventilation relative to drainage. It is unclear whether this shift represents a short-term anomaly or the beginning of a longer-term trend.

The total amount of methane handled by drainage systems has fluctuated over time, although the long-term trend has been down (again reflecting the shift away from underground mining). The percentage of methane drained that is captured and used increased sharply between 1990 and 1995 (from 25.3 percent to 81.8 percent). However, since 1995 the methane capture percentage has remained remarkably consistent, at approximately 80 percent. This stability in part reflects the fact that more than half of the mines with capture and use projects in 2007 (8 out of 15) began these projects on or before 1995; thus there is a large core set of such projects that was in operation in both years.

Table 2 - Historical Trends in the Number of Mines Using Methane Drainage and Capture/Utilization

	Year							
	1990	1995	2000	2003	2004	2005	2006	2007
Mines with Drainage Systems	**33**	**25**	**21**	**18**	**21**	**24**	**21**	**20**
Mines with Gob Wells	NA	NA	NA	8	11	15	12	12
Mines with Gob and Horizontal Pre-Mining Wells	NA	NA	NA	3	3	3	3	3
Mines with All 3 Drainage System Types	NA	NA	NA	7	7	6	6	5
Mines with Capture/Use Projects	**7**	**12**	**13**	**12**	**12**	**15**	**15**	**15**
Pipeline	6	12	10	11	10	13	13	13
Electricity Generation	0	0	0	1*	1	1	1	1
Vent. Air Heating	0	0	0	1	1	1	1	1
Thermal Coal Drying	0	1*	1*	1*	1*	1*	1*	1*
Unspecified	1	0	3	0	0	0	0	0

Source: Developed using data in U.S. EPA, Coal 07 draft.xls file.
*This mine also sells a portion of its recovered methane to a pipeline.

Table 3 - Historic Trends in Ventilation System Emissions and Methane Drainage, Capture/Use, and Venting

	Year				
	1990	**1995**	**2000**	**2005**	**2007**
Total Underground Mine Emissions (mmcf)	**151.5**	**113.6**	**96.1**	**85.6**	**86.2**
Ventilation System Emissions (mmcf)	**111.4**	**106.9**	**86.9**	**74.5**	**78.9**
Amount of Methane Drained (mmcf)	**53.7**	**36.9**	**45.5**	**47.4**	**37.1**
Percent of Drained Methane Captured/Used	25.3%	81.8%	79.7%	76.5%	80.2%
Percent of Drained Methane Vented	74.7%	18.2%	20.3%	23.5%	19.8%

Sources: Developed by combining data in U.S. EPA, *Draft Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007*, Feb. 2009, p. 3-37, with data in EPA's Coal 07 draft.xls file.

Regional Prevalence of Degasification Techniques

Table 4 shows the distribution of the drainage system types in operation in 2007 across the different regions and states. As this table indicates, most mines with drainage systems (14 of the 20) are located in Appalachia. This is in large part a reflection of the fact that most of the nation's underground mines (93 percent of those in operation in 2007) are located in Appalachia. Note, however, that all five of the mines that use all three drainage system types are in Appalachia, and in fact four of these five mines are in Alabama. Alabama is host to the deepest, and gassiest, underground coal mines in the country; degasification of these mines requires the most powerful mine fans in use in the U.S., as well as the deployment of all three drainage techniques.

In contrast, none of the mines in the Interior region operated drainage systems in 2007. In the West, there were six such systems in use—four “gob only” systems and two systems combining gob drainage with horizontal pre-mining boreholes.

Table 4 - Number of Underground Mines Employing the Three Drainage System Types, by Region and State (2007)

Region/State	Total Number of Underground Mines	Number of Mines with Gob Drainage Systems Only	Number of Mines with Gob and Horizontal Pre-Mining Drainage	Number of Mines with All Three Types of Drainage Systems
Alabama	9	1	0	4
Kentucky	267	0	0	0
Maryland	3	0	0	0
Ohio	11	0	0	0
Pennsylvania	62	3	0	0
Tennessee	10	0	0	0
Virginia	89	0	0	1
West Virginia	227	4	1	0
Appalachia	**678**	**8**	**1**	**5**
Arkansas	1	0	0	0
Illinois	14	0	0	0
Indiana	9	0	0	0
Oklahoma	2	0	0	0
Interior	**26**	**0**	**0**	**0**
Colorado	8	2	1	0
Montana	1	0	0	0
New Mexico	1	0	1	0
Utah	13	2	0	0
Wyoming	1	0	0	0
West	**24**	**4**	**2**	**0**
U.S.	**728**	**12**	**3**	**5**

Source: Developed using data in U.S. EPA, Coal 07 draft.xls file.

The Relationship Between Mining Method and Degasification Utilization

The preceding analyses show that the use of drainage is, and has always been, relatively uncommon at U.S. underground coal mines. This is a key point, given that the commercial technologies currently available for capturing and utilizing CMM must be used in conjunction with drainage systems. The relative rarity of such systems thus limits the development of CMM projects.

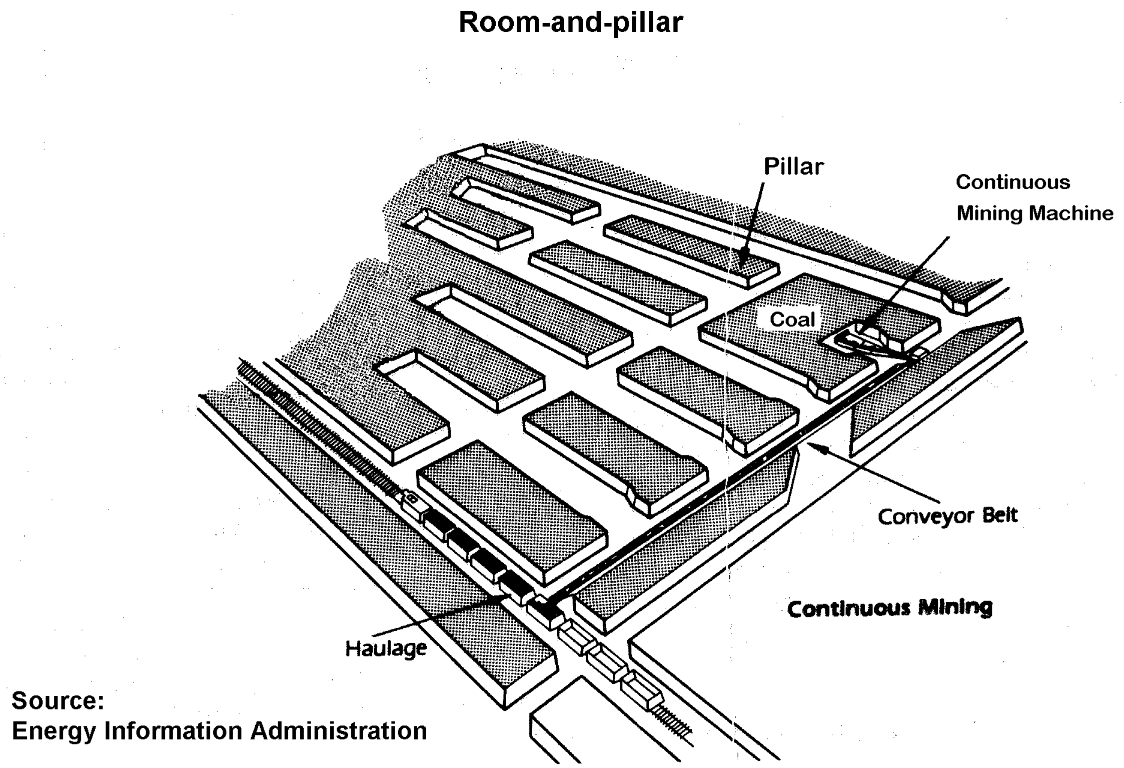
Yet as we shall see in Chapter 3, while drainage system use is relatively uncommon for the underground mine population as a whole, it is in fact quite common under certain specific conditions. Two factors in particular define the conditions under which degasification becomes common: mining method and the gassiness of the mine. The influence of both of these factors on drainage utilization will be discussed in depth in Chapter 3. At this point, as an introductory background to the Chapter 3 discussion, we will provide a brief overview of U.S. underground mining methods and their relationship to drainage utilization.

Two distinct mining methods are employed in U.S. underground coal mines: *room and pillar* and *longwall*. Both mining methods are well suited to the relatively flat lying, or horizontal coal seams characteristic of the U.S. In room and pillar mining, the mine is laid out in a checkerboard fashion, with square or rectangular pillars of coal created by the mining out of rooms on each side of a pillar (see Figure 11). The pillars, which might typically range in size from 60 feet by 60 feet to 100 feet by 100 feet, serve to support the roof as mining advances in the rooms. Typically, a set of approximately five parallel rooms, called entries and typically about 20 feet wide, are driven for a length of a few thousand feet, with perpendicular crosscuts driven every 100 feet or so to connect the entries (thereby blocking out pillars). In the "continuous mining" version of room and pillar mining, a continuous mining machine excavates the coal and loads it onto a shuttle car for transportation to a conveyor belt. The continuous miner advances each entry or crosscut in increments of about 20 feet at a time; once this limit is reached the continuous miner moves to a different entry or crosscut, thereby allowing a roof bolter following the continuous miner to install roof bolts to support the newly exposed roof. In the "conventional" form of room and pillar mining, explosives are used in place of the continuous miner to excavate the coal. In conventional mining the mining process consists of five steps—mechanically undercutting the coal seam, drilling holes into the seam, loading the holes with explosives and detonating the charge, loading the broken coal into shuttle cars, and bolting the roof in the newly excavated area.

Once the entries have been driven their full planned length, "retreat mining" begins, and the remaining pillars of coal are partially extracted. The roof is allowed to cave in behind the retreating operation as coal is removed from the pillars.

In longwall mining, the room and pillar technique is first used to develop or block out a large panel of coal for the longwall unit by excavating entries around the panel (see Figure 12). A typical longwall panel may be approximately 1000 feet across, one to two miles long, and four to seven feet high (depending on the seam thickness). Once development of the longwall panel is completed, a coal shearer cuts the coal from the thousand foot face as it passes back and forth across the face. The shearer rides on top of an armored chain conveyor that parallels the face; the coal cut by the shearer is transported via the chain conveyor to a belt conveyor in one of the entries running alongside the longwall panel. The shearer, conveyor, and longwall personnel are protected under self-advancing hydraulic roof supports. As the shearer passes each roof support, the support is advanced closer to the face to protect the miners and equipment from the newly exposed roof. As the roof supports advance, the roof behind the supports is allowed to collapse, creating the gob. Mining continues in this manner until the entire panel of coal has been extracted, at which point the longwall equipment is moved to a newly developed panel.

Figure 11 - Schematic Illustrating Room and Pillar Mining



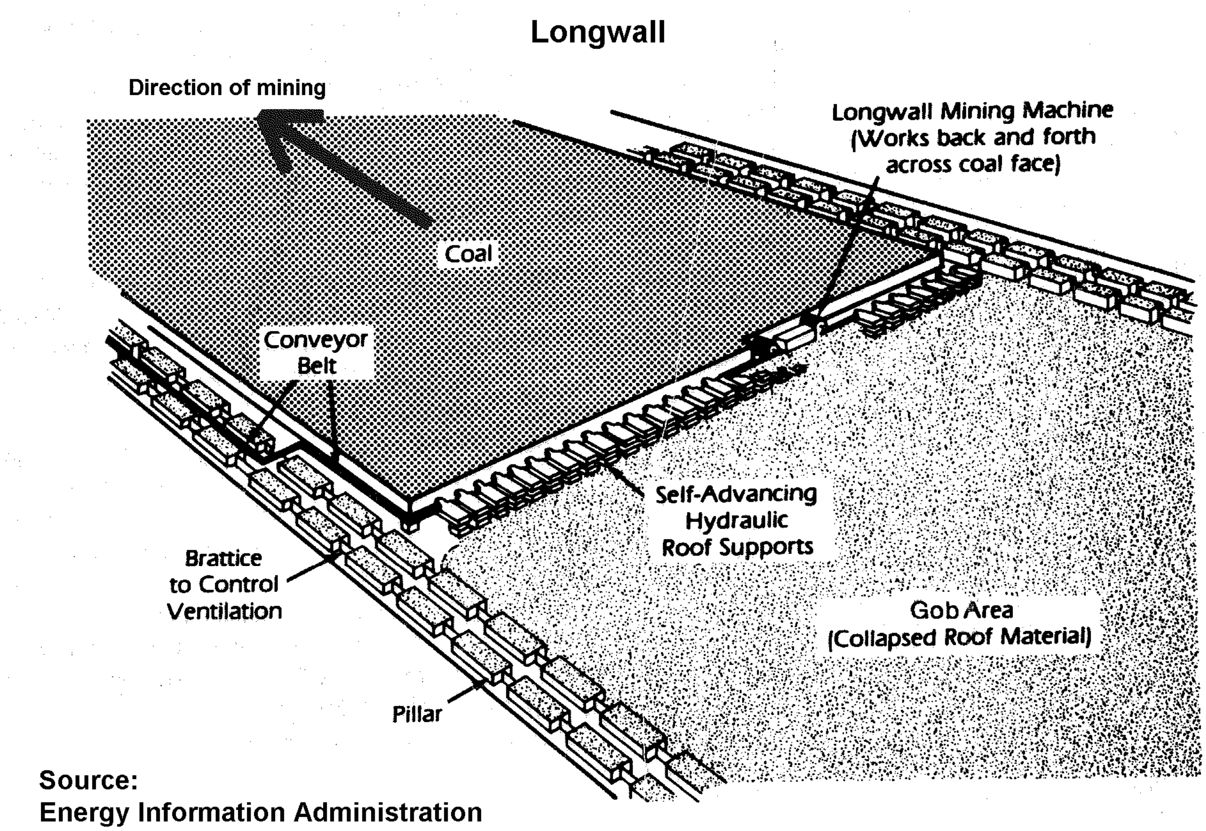
Source: Energy Information Administration, *Longwall Mining*, DOE/EIA-TR-0588, March 1995, p. 4.

Although longwall mining has been in use for centuries overseas, in this country room and pillar mining is the traditional method, and it remains the most commonly used of the two methods. In 2007, an estimated 681 of 728 U.S. underground mines used the room and pillar technique, with the remaining 47 mines employing the longwall method.[10] While the use of drainage systems is relatively common at longwall mines, such systems are non-existent at room and pillar mines. In part this reflects the fact that longwall mines tend to have much higher production rates than room and pillar operations. As a consequence longwalls tend to have higher methane liberation rates than do room and pillar mines, and often need to use drainage in combination with ventilation to keep methane concentration in the mine from approaching explosive levels. However, there are other, more complex reasons for the observed relationship between mining method

[10] Estimated based on information from CoalUSA, U.S. EPA's, Coal 07 draft.xls file, and mine production data from EIA.

and drainage system utilization; the causes underlying this relationship will be explored in depth in Chapter 3. For now, we only wish to note that the continued prevalence of room and pillar mining in the U.S. has acted as a significant constraint on the number of coal mine drainage systems, and hence the number of CMM projects. The continued dominance of the room and pillar method, in number of mines if not total production, reflects the fact that the pre-conditions for the successful operation of a longwall are more limiting than the pre-conditions needed for a successful room and pillar mine. For one, the longwall method is much more capital intensive than room and pillar mining, a fact which limits the former to large coal companies with access to the necessary capital. Furthermore, because of the large capital investment required, a longwall mine requires a relatively large continuous block of coal reserves to ensure that production over the life of the mine will be sufficient to justify the capital investment. Smaller blocks of reserves must be extracted using the room and pillar method.

Figure 12 - Schematic Illustrating Longwall Mining



Source: Energy Information Administration, *Longwall Mining*, DOE/EIA-TR-0588, March 1995, p. 4.

Furthermore, not all geologic conditions are well-suited to longwall mining, a fact which further limits its application. In general, longwall mining works best in coal seams that are relatively flat lying, uniform in thickness, and free of discontinuities such as faults. Oil and gas wells present significant obstacles to longwall operations, as it is necessary to leave pillars of coal around the wells to protect them. (Room and pillar operations can more readily mine around wells and coal seam discontinuities; longwalls cannot.) The rock comprising the mine floor must be hard enough to bear the pressure from the hydraulic roof supports, while the strata overlying the coal seam must break rather than "hang up" behind the supports (the latter being a dangerous condition which can overload the supports or cause violent air blasts when large blocks of rock finally collapse). There is, however, one geologic factor that favors, and in some cases necessitates, the use of longwall mining—seam depth. As seam depth increases, pillar size must be increased to support the roof at room and pillar mines. At some point, the resulting reduction in coal recovery rates renders room and pillar mining uneconomic. Specifically, seams deeper than 1000 feet often must be mined using the longwall method. However, at present large quantities of coal remain at shallower depths that are still accessible to room and pillar mines.[11]

Finally, it should be noted that the high productivity of longwall mines acts as a significant constraint on the number of longwalls. Although longwalls comprised only six percent of the total number of mines in operation in 2007, they accounted for 52 percent of total underground production in that year. The average production per longwall mine was 4,273,000 short tons in 2008;[12] at this average rate the entire 2007 production from room and pillar mines in the U.S. could be replaced by fewer than 47 new longwall mines (the existing longwall population). Thus, even if the potential applications of longwall mining were not constrained by company size, reserve block size, and geologic conditions, the ultimate constraint imposed by current coal demand would limit the longwall population to less than 100 mines. In point of fact the high and increasing productivity of longwall mines has enabled a significant reduction in the longwall mine population, by nearly 50 percent since 1987.[13]

1.3.4 Future Technologies

The historic trends indicate limited growth in the number of methane capture/use projects since 1995, and stasis in the effectiveness of these projects in reducing emissions from drainage systems. The number of mines using such systems is actually in decline, as is the number of longwall operations that represent the most likely market for drainage, capture and use projects. Given these trends, it might be asked whether technologies currently in development, or in use in other countries, might hold out promise for re-energizing the CMM industry. Technologies with the potential to do so are more likely to be found in the areas of methane capture and utilization than in drainage. While there are a couple of drainage techniques that either have been used here in the past, or are used extensively outside the U.S., neither of these techniques has proved popular here. One such technique, longhole horizontal boreholes, involves drilling lengthy (>1000 feet) horizontal boreholes from within the mine using directional drilling techniques. These boreholes, which are drilled in advance of mining, produce high purity methane with a recovery rate of about 50 percent. They require long diffusion periods and are most effective in gassy, low permeability coal seams. Two mines in the western U.S. have used longhole horizontal boreholes in the past, but while both of these mines continue to

[11] Energy Information Administration, *Longwall Mining*, DOE/EIA-TR-0588, March 1995, pages 3 and 5.
[12] Weir International Inc., *United States Longwall Mining Statistics 1989-2007*, 2008, Table 2.
[13] Weir International Inc., *United States Longwall Mining Statistics 1989-2007*, 2008, Figure 1, and

operate drainage systems the longhole horizontal technique does not currently play a role in these systems.

The second drainage technique, cross-measure boreholes, involves drilling angled boreholes from inside the mine into the strata lying above and below the coal seam (see Figure 13). The gas recovered from cross-measure boreholes is similar in quality to that produced by gob boreholes. Although cross-measure boreholes are used extensively in Europe and Asia, gob boreholes are preferred in the U.S. A mine in Colorado has used cross-measure boreholes in the past, but found them ineffective given the conditions at this mine.[14]

As we have seen, current methane capture and utilization projects are limited almost exclusively to one type—sales to nearby natural gas pipelines. Yet clearly there are many other commercially-available utilization technologies. EPA identifies the following utilization options for high quality gas (>950 Btus/cubic foot) of the type produced by pre-mining boreholes:

- Sales to natural gas pipelines;
- Use as chemical feedstock; and
- Compress or liquefy gas for use as transportation fuel.[15]

Although sales to natural gas pipelines require a high-quality gas, it is clear that many mines are able to sell the gas recovered from gob boreholes. In some cases, mines may be able to mix gob gas with gas captured from pre-mining boreholes to achieve a pipeline-quality product. However, in 2007 seven mines using gob boreholes exclusively sold recovered methane to pipelines; these mines are presumably upgrading the gas prior to sale.

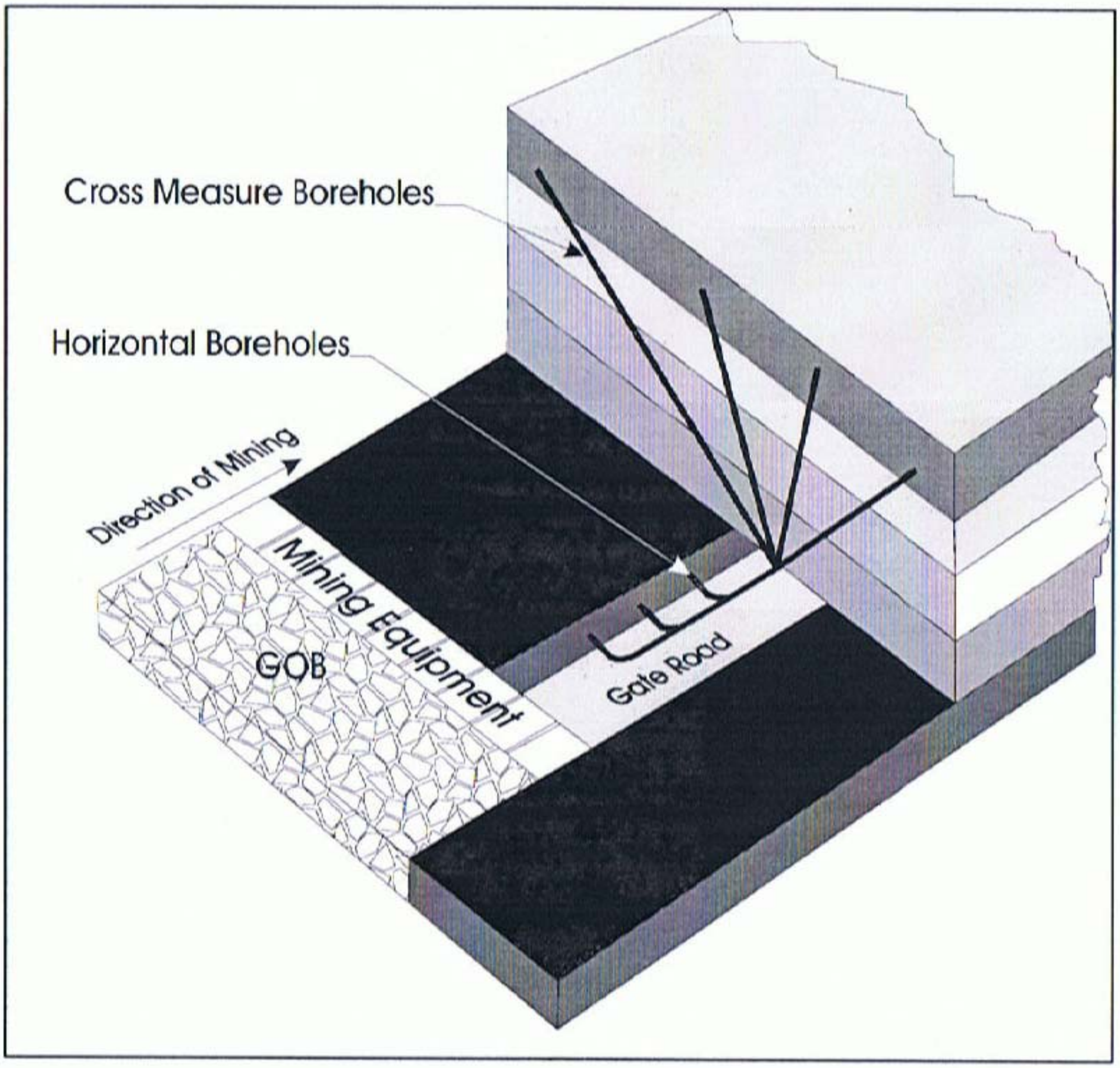
In cases where upgrading may not be technically or economically feasible, the following utilization options are available for medium quality gas (350 to 950 Btus/cubic foot) of the type produced by gob boreholes:

- Co-firing with coal in utility or industrial boilers;
- Use as fuel for internal combustion engine;
- Use as supplement to natural gas in blast furnaces;
- Use to produce liquefied gas;

[14] U.S. EPA, *Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 2002-2006*, EPA 430-K-04-003, September 2008, pages 2-6 and 2-7.
[15] Ibid., p. 2-8.

- Use as fuel for micro-turbines or fuel cells;
- Use to fuel thermal dryers in coal prep plants;
- Use as fuel to heat mine facilities or mine intake air.[16]

Figure 13 - Cross-Measure and Horizontal Pre-Mining Boreholes



Source: U.S. EPA, *Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 2002-2006*, EPA-430-K-04-003, Sept. 2008, p. 2-6.

In addition to the above *utilization* options, flaring is often mentioned as a possible methane *destruction* option. There are, however, two key drawbacks to flaring which have thus far kept it from being utilized at U.S. coal mines. First, unlike methane

[16] U.S. EPA, *Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 2002-2006*, EPA 430-K-04-003, September 2008, pages 2-8.

utilization options, flaring offers no revenue enhancing or cost reduction benefits to mine operators, beyond the value of any emission reduction credits that flaring projects may earn. Second, and even more importantly, there are significant safety concerns surrounding the use of flaring at coal mines. Specifically, the concern is that the flame from a flare could propagate back down the borehole and into the mine, where it could cause an explosion or mine fire.

While all of the other alternatives to pipeline sales are feasible in theory, many of the off-site applications (e.g., use of the gas as a feedstock for a chemical plant, a blast furnace fuel, or a transportation fuel) may be impractical for the majority of coal mines given their remote locations far from industrial centers. On-site applications are more promising, although it must be emphasized that some of these applications are not widely needed by the coal industry. For example, while a significant percentage of coal is processed in on-site or nearby coal prep plants, few of these plants perform the intensive kinds of preparation that requires thermal drying of the coal. Similarly, few mines need to heat their intake air, since once it is drawn underground it usually reaches a comfortable temperature of about 50° F regardless of the season (although, as we have seen, one mine is using its recovered methane to heat the mine air).

However, one on-site utilization option that meets a need shared by all coal operations is electricity generation. Underground coal mining is an electricity-intensive industry; at many mines *all* of the equipment used underground is powered by electricity. Furthermore, unlike natural gas pipelines, which require a high quality gas, gas turbine electricity generators can operate directly off of the gas produced by gob wells.[17] Mine-site electricity generators fueled by coal mine methane would reduce power costs—a major component of a mine's total operating costs—and would also provide an additional revenue stream in cases where excess electricity can be sold back to the grid. Since 2000, two different coal mines have used captured methane for electricity generation.

It must, however, be emphasized that without a significant increase in the number of mines using borehole drainage techniques, the remaining potential applications of electricity generation, or other on-site and off-site CMM utilization options, are quite limited. As we have already seen, 20 mines are currently using methane drainage, and 15 of these mines are already capturing and utilizing the methane. This leaves a market for current, commercially-viable CMM utilization technologies of only 5 mines.

The real opportunity for achieving significant reductions in coal mine methane emissions thus appears to lie not with drainage systems, but with ventilation. In 2007, the methane emissions from ventilation systems were more than 10 times greater than drainage system emissions (78.9 million cubic feet versus 7.3 million cubic feet; see Figure 10). However, the technology available to tap into this much larger potential market is as yet unproven commercially, at least in the U.S. The technical barrier to the commercialization of methane destruction or utilization technology capable of being used in conjunction with ventilation systems has been the highly dilute character of the

[17] Ibid., p. 2-11.

methane emitted by these systems. Typically the mine air vented from return air shafts is less than 1 percent methane. The utilization technologies considered thus far require gas with a much higher methane content.

However, there are some potentially promising technologies on the horizon. These include the following:

- MEGTEC Systems' VOCSIDIZER™ and Biothermica Technologies Incorporated's VAMOX™ system, both of which thermally oxidize the methane in mine air using thermal flow-reversal reactors (TFRR). The TFRR process applies the principle of regenerative heat exchange between a gas and the solid bed of a heat-exchange medium. This technology is being used on a commercial scale outside the U.S. The first such commercial project became fully operational at an Australian coal mine in September 2007. In the U.S. a couple of demonstration projects of the technology are now underway. One of these demonstration projects, using the VOCSIDIZER™, became operational in April 2007 at a closed mine in West Virginia. The other, at an active mine in Alabama, received MSHA approval in April 2008 and began operations in January 2009 – see case study on this project below. This latter project uses Biothermica's VAMOX™ system. Biothermica is planning to commission a second demonstration project later in 2009, at a mine in British Columbia.

- Catalytic flow reversal reactors (CFRR) are similar to TFRR technologies, but also include a catalyst to reduce the auto-oxidation temperature of methane to as low as 350°C. CANMET has applied this technology on a pilot scale, and is studying options for recovering and using the waste heat from the process. Two primary options for converting the heat energy from CFRR (or TFRR) technology into electricity are (1) using the heat to generate steam for use in a steam turbine and (2) pressurizing the ventilation air and running it through a gas turbine.

- Volatile organic compound (VOC) concentrators are currently used to raise the concentration of VOCs in industrial-process air streams, and could conceivably raise the methane content of mine ventilation air to as much as 20 percent. At this level the ventilation air might serve as an adequate fuel in a gas turbine or reciprocating engine.

- Lean Fuel Gas Turbines are modified turbines designed to operate either directly on ventilation air, or on ventilation air methane that has been enhanced (e.g., by a VOC concentrator or by mixing with more concentrated fuels). Examples include:

    - Carbureted gas turbines (CGT) are aspirated turbines that use a homogeneous mixture of air and methane. Since methane must comprise at least 1.6 percent of the mixture by volume most ventilation air streams will require enhancement prior to entering the turbines air inlet. with the latter comprising at least 1.6 percent of the mix by volume. CGT technology has been tested on mine ventilation air at a mine in Australia.

- Lean-fueled turbines with catalytic combustors compress the air/methane mixture and then combust it in a catalytic combustor. The technology's developer, CSIRO Exploration and Mining of Australia, in conjunction with Shanghai Jiatong University and Huainan Coal Mining Group, is planning a pilot scale project in China that will utilize ventilation air with a concentration of about 1 percent methane.

- Hybrid coal and ventilation air-fueled gas turbine technology is designed to cofire waste coal and ventilation air in a rotary kiln, capture the heat in an air-to-air heat exchanger, and use the hot air to drive a gas turbine. Mine ventilation air with a methane content of 1 percent can be used to meet 15 to over 80 percent of the technology's fuel needs. CSIRO is developing a pilot-scale demonstration of the technology.

- Lean-fueled catalytic microturbine technology, capable of operating on air with a methane content of 1.3 percent, is currently under development by two U.S. companies working jointly (FlexEnergy and Capstone Turbine Corp.)

In addition to the above new technologies, ventilation air can also be used to meet all or part of the combustion air requirements of existing, commercial engine and turbine technologies. In these applications, the dilute methane contained in the ventilation air will displace a small fraction of the primary fuel (thereby reducing fuel costs). A mine in Australia is currently using ventilation air as the combustion air for 94 1-MW Caterpillar engines. Also, Powercoal, an Australian utility, is developing a system that will utilize mine ventilation air as the combustion air for a coal-fired steam power plant.[18]

1.3.5 Case Study of Biothermica's VAMOX Technology

Since the end of January 2009, Biothermica Technologies has operated a VAM oxidation project at Jim Walter Resources' Blue Creek Mine No. 4 in the Black Warrior coal basin near Brookwood, Alabama.[19] It is the first project to obtain approval to operate from MSHA, as an addendum to the mine ventilation plan, and to successfully deploy VAM technology at an active mine in the U.S. The project's developers have submitted documentation to apply for validation of carbon offset credits from the project, as calculated according to the CDM methodology for CBM, CMM and VAM projects[20] and issued under the Voluntary Carbon Standard. The project design anticipates that, over a

[18] U.S. EPA, *Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 2002-2006,* EPA 430-K-04-003, September 2008, pages 2-13 through 2-16.
[19] All information in this case study was obtained via personal communication with Biothermica Technologies' project manager for the Blue Creek demonstration project, Raphael Bruneau, received May 19, 2009.
[20] ACM0008, version 5 – VAM destruction through flameless oxidation project type.

10-year period of operation at mines No. 4 and No. 7,[21] utilization of VAMOX will reduce methane emissions from the mines by more than 329,000 MT CO_2e. It should be noted that a a CMM drainage and collection system is also in place at this mine, further reducing emissions of methane.

The technology employed is a single regenerative thermal oxidation unit (thermal flow-reversal reactor, as described in section 1.3.4 above). The unit is both physically and electrically separate from the mine's ventilation and other safety systems in order to ensure worker safety in the active mine. As a technological demonstration, the project is sized to oxidize just a fraction of the ventilation air emitted from the No. 4 mine bleeder shaft (30,000 cubic feet per minute). Despite the chosen size of this initial project, VAMOX technology is scalable to handle higher ventilation air flow rates through a single unit, or may also be deployed in groups.

The demonstration has been highly successful to date, averaging 90 percent system availability over the four month period, with recent availability statistics reaching 95 percent. Since project initiation, the ventilation air oxidized by the system has averaged 0.8 percent methane, although the technology is capable of handling VAM concentrations as low as 0.2 percent. Further, VAMOX is designed to operate at a very high destruction efficiency (up to 96 percent) and to produce no emissions other than CO_2 and water. The technology also requires very minimal fuel (propane) and electricity input to start up and operate,[22] increasing the emission reduction value of the project.

[21] After three years at Mine No. 4, the technology will be redeployed at No. 7 for the remainder of the 10-year project crediting period.
[22] Once the project has reached full operation in 2010, total operational energy and electricity use-related emissions are estimated to be approximately 600 MT CO_2e/year, where as reductions are estimated at 34,259 MT CO_2e/year.

2 REVIEW OF CURRENT AND PENDING REGULATIONS GERMANE TO CMM PROJECTS

A key component of all robust GHG offset project protocols is a procedure to assess the project's regulatory additionality status. Essentially, if a project must be undertaken in order to meet federal, state or local regulatory requirements, then it cannot be considered additional to what otherwise would have happened. Such a project causes no change or reduction in the baseline "business-as-usual" emissions, and hence it does not (or should not) qualify for emission reduction credits. Thus the development of any offsets project performance standard must include a regulatory review to determine whether or not, and under what conditions, a project may be necessitated by regulations. Since project developers may undertake projects in anticipation of likely future regulations as well as current regulations, such a review should encompass both current and pending regulations at the federal and state level.

In the following pages, we document the results of a review of regulations germane to CMM projects. At the outset, we should emphasize that there are at present no federal, state or known local regulations prohibiting or otherwise limiting methane emissions from underground coal mines. That said there are regulations that may *influence* the type(s) of degasification systems employed, and as some of these systems are more amenable to methane capture and use than others, these regulations may in turn affect project opportunities. Of particular importance are federal and state mine safety regulations addressing allowable methane concentrations in mine air.

2.1 Federal and State Coal Mine Safety Regulations

Methane is explosive when it comprises 5 to 15 percent of the mine atmosphere. Therefore, to ensure that methane remains well below the concentrations at which it becomes explosive, the Federal Coal Mine Health and Safety Act of 1969 requires that methane levels be kept below 1 percent at the working face. To help ensure that this requirement is met, all underground mines (gassy and non-gassy) are required, under the same Act, to develop ventilation systems that meet detailed specifications laid out in the federal regulations. The methane concentration limits and ventilation requirements are enforced by the Mine Safety and Health Administration (MSHA).

While there are no requirements to develop drainage systems (either pre-mining or gob), certain types of gassy mines may have difficulty meeting the 1 percent requirement using ventilation alone. At these mines the decision to utilize drainage may be motivated primarily by the MSHA safety regulations. As shall be seen in Chapter 3, the available data tends to support the hypothesis that many if not most mines currently using CMM drainage systems are doing so as a response to the MSHA regulations. While there is no ancillary requirement that the methane routed through such systems be captured and utilized rather than vented, the influence of the safety regulations on the decision to use one or more of the available drainage techniques has important implications for the development of a CMM protocol—including the specification of common practice standards. These implications will be explored in much greater depth in Chapter 3. For now, it is sufficient to understand that MSHA regulates the allowable concentration of methane in the mine, and that both ventilation and drainage are used to dilute and remove the methane from the coal seam or the mine.

It should be noted that major coal mining states also have regulations limiting allowable methane concentrations in the mine. In fact, prior to 1969 the regulation and enforcement of coal mine safety was left primarily to the states. Thus in many cases the state regulations pre-date the federal regulations. However, the state and federal regulations generally agree on the key requirements limiting methane concentrations in the mine. For example, Pennsylvania, West Virginia and Illinois all limit methane concentration to 1 percent at the working face.[23]

2.2 Other Federal and State Regulations, Programs, Subsidies and Legal Developments

Beyond MSHA, the EPA and BLM each have existing jurisdiction and regulatory roles related to coal mines. New regulation of emissions by the EPA is proposed in pending federal climate and energy legislation or may result from the EPA's own rulemaking process in response to *Massachusetts v. EPA.*

Discussions with staff from the EPA's Coalbed Methane Outreach Program and a search of the published Agency rulemaking agendas and plans indicate that the Agency currently has no regulations on the books or in development that would require the collection or destruction of CMM. However, the EPA has just issued a proposed endangerment finding covering GHGs under the Clean Air Act. Once final, this finding will trigger a rulemaking process that is expected to have implications beyond the mobile emissions sources addressed in the finding. A BACT requirement for coal mines could, conceivably, involve a requirement that mines destroy or utilize CMM emissions.

Or, Congress may soon charge the EPA with direct regulation of methane emissions from coal mines. The discussion draft version of H.R. 2454, the American Clean Energy and Security Act of 2009 (ACES), as released 15 May 2009,[24] would likely lead to regulation of coal mine methane emissions under Title VIII, "Additional Greenhouse Gas Standards." Section 811, "Stationary Source Standards," requires the EPA to develop a list of uncapped (under the GHG cap and trade program established under Title VII of the Act) stationary sources that are responsible for a substantial portion of the remaining emissions of GHGs left outside the cap.[25] EPA would then be required to set Standards

[23] Pennsylvania Dept. of Environmental Protection, *Safety Laws of Pennsylvania for Underground Bituminous Coal Mines,* Act 55, SB 949 Session of 2008; State of West Virginia Office of Miner's Health, Safety and Training, *Mining Laws, Rules and regulations 2008 Reference Manual*; State of Illinois, *Coal Mining Act* (225 ILCS 705/).
[24] http://energycommerce.house.gov/Press_111/20090515/hr2454.pdf
[25] The bill directs the EPA to create a list of stationary sources to regulate consisting of those which "individually had uncapped greenhouse gas emissions greater than 10,000 tons of carbon dioxide equivalent and that, in the aggregate, were responsible for emitting at least 20 percent of the uncapped greenhouse gas emissions." Further, with respect specifically to emissions of methane, the list shall include "each source category that is responsible for at least 10 percent of the uncapped methane emissions.

of Performance (SOP) for these sources under the New Source Performance Standards section, Section 111, of the Clean Air Act.[26] Under the CAA, "new sources" are broadly defined to include any new construction or modifications made to existing facilities that take place after promulgation of the SOP that increase emissions from the stationary source. Thus a "new source" would, conceivably, include the opening of a new ventilation shaft at any existing, active mine.

According to the EPA's analysis of the bill,[27] conducted in response to an official request from its authors, the "Sources potentially covered by this provision include at a minimum:

- Landfills
- Coal Mines
- Natural Gas Systems"

The list of stationary sources to be developed according to Sec. 811 is subject to a 10,000 MT CO_2e threshold. While the EPA's threshold analysis for the recently released draft federal Mandatory GHG Reporting Rule states that 122 mines would be subject to such a reporting threshold, this includes only underground mines. The provision for development of NSPSs in ACES, rather, requires EPA to regulate *all types* of stationary sources based on their significance in contributing to uncapped emissions. Any mine, underground or surface, that liberates 20.833 million cubic feet of methane per year would exceed the 10,000 MT CO_2e threshold. In contrast, MSHA's threshold to distinguish gassy from non-gassy mines is 100,000 cubic feet of methane per day, or 36.5 million cubic feet of methane per year. Hence the mines to be regulated under Sec. 811 would include all gassy underground operations, as well as many non-gassy mines. Due to this provision, EPA omitted the possibility of using domestic emissions offsets from landfill or coal mine methane emissions reduction projects when it modeled the offsets supply and marginal abatement costs of the draft Act.

It is unclear what form such a standard of performance might take with respect to emissions of methane from coal mines. Standards of performance typically set maximum allowable emission rates. However, EPA is provided flexibility in the type of standard it may develop for each source category should a standard of performance be deemed inappropriate, technologically infeasible or too costly for a particular source. Other possible types of standards that may be promulgated, *without regard to determination of feasibility as is usually required under CAA Sec. 111(h)*, include "design, equipment,

…[and] shall include industrial sources, the emissions from which, when added to the capped emissions from industrial sources, constitute at least 95 percent of the greenhouse gas emissions of the industrial sector."

[26] All new standards must be finalized within 10 years of enactment of the legislation. Standards for categories that combine to account for at least 80 percent of the emissions from the listed sources must be promulgated within three years of enactment.

[27] EPA Preliminary Analysis of the Waxman-Markey Discussion Draft, the American Clean Energy and Security Act of 2009 in the 111th Congress. *Appendix*. 20 April 2009.

work practice, or operational standard, or any combination thereof." Regardless of the type of standard promulgated to reduce emissions of methane from coal mines, the cost per ton of emissions reduced through implementing the required technologies or practices must not exceed the price of emissions allowances, as projected by the Agency with regard to the cap and trade program.

Finally, the Department of Interior's Bureau of Land Management also holds jurisdiction over particular facets of US coal mining operations and their associated methane emissions. The BLM is the federal body charged with issuing leases for the development of oil and gas, and coal resources located on federal lands. The BLM currently has no stipulations against venting methane from federally leased mines. The Bureau does, however, require coal lease holders to obtain separate leases for gas development, should they wish to develop *CBM* wells. The issue of split mineral rights for gas and coal has led to much confusion and litigation related to the ownership of *CMM* rights and the circumstances under which gas leases are required for CMM projects. The issue of ownership rights is discussed further in the following subsection.

2.2.1 Federal and State Regulations Concerning Coal Bed Methane (CBM) Ownership

Some regulations have as their goal the removal of barriers to the development of CBM and CMM projects. Disputed ownership of the mineral rights is one such barrier that has acted as a deterrent to the development of CBM. In many cases more than one party—including, e.g., the mine operator, an oil and gas producer, the owner of the surface rights, or the federal government —may have a claim to the CBM or CMM to be captured and used.

On privately-owned mining lands, which are under the regulatory jurisdiction of state governments, the approach to clarifying ownership has been ad hoc. The development of ownership legislation by state governments was originally spurred by the potential for CBM resource development incentivized by federal tax credits (see Section 29 tax credit discussion in section 2.2.5 of this report, below). During the 1980s and 1990s, a number of major coal producing states—including Alabama, Virginia and West Virginia—enacted legislation designed to clear ownership disputes that were acting as a barrier to CBM and CMM project development. These laws paved the way for a boom period of CBM development that capitalized upon the gas production incentives available at the time. Since then, the federal government included its own default CBM legislation in the National Energy Policy Act of 1992 (EPACT), to be applied in states without their own CBM programs. However, most states opted out of adopting the federal language. The various federal and state laws all incorporate a "forced pooling" provision, which enables project development to proceed while mineral rights claimants work to resolve ownership disputes.[28]

[28] Alternative Energy Development, Inc., *Coalbed Methane Legislation and Recovery in Alabama, Pennsylvania, Virginia and West Virginia*, White Paper prepared for EPA, Nov. 1997, pages 2 and 3.

In addition to being charged with administering leases of federal coal resources, the federal government is entitled to royalties from the sale of energy products produced from mineral and gas resources. Thus, the government has an interest in requiring that leases specific to coal-related gas resources be obtained and royalties paid on any gas sales that result from the leased resource. The Mineral Lease Act of 1920 clarified that CBM is to be developed under gas, not coal leases. Table 5 summarizes the resolution of CBM(/CMM) ownership on private lands in those states that have enacted clarifying legislation, and on federally-owned lands.

Table 5 - Summary of CMM Ownership Rights under Existing State and Federal Laws

State	Coal Lessee	Gas Lessee	Comment
Alabama	X		
Illinois	X		In coal seam or mine void only
Kentucky		X	
Montana	X		
Pennsylvania	X		
West Virginia			Case-specific depending on language of deed and intent of parties
Wyoming		X	
Federal Lands		X[a]	

Source: US EPA Coalbed Methane Outreach Program. *Coalbed Methane Extra*. Fall 2007. p. 4.

[a] Based on our review of the recent case history related to CMM, rather than CBM, development from federally-leased coal, we suggest that the EPA's assertion cited here (that the gas lessee is the party entitled to coal-derived methane) is limited to CBM.

It was not until much more recently that CMM, as opposed to CBM, became economical for coal mine operators to collect and utilize or sell. The determination of whether or not there is a requirement to obtain a gas lease, and if so, how that gas lease may be acquired, has not been definitively resolved with respect to CMM from federal lands. This is due to conflicting assessments of how the resources involved should be defined, and thus, what laws are applicable to the extraction of those resources. Recent litigation has sought to clarify whether production of CMM for sale, as with CBM, is subject to the producer holding the gas lease.

In 2001, the Utah State Office of the BLM issued a Policy Memorandum stating that gas development is inconsistent with coal mining and therefore, gas rights are not to be issued for any lands that are actively mined or will be mined within ten years. As a result, the gas lease related to the Aberdeen mine that was put up for competitive sale was laden with mine safety precautions in order to separate the 'incompatible' operations of gas and coal production. This resulted in the losing bidder, Vessels Coal Gas Inc., filing suit against the BLM. The *Vessels* case was decided by the Interior Board of Land

Appeals in June 2008.[29] The Appeals court upheld the prior judgment that methane from *vents* opened by mine operators due to MSHA regulations (VAM) is not subject to gas leases under the Mineral Leasing Act of 1920, because VAM is contaminated by mine air and thus, not a gas that is "produced in a natural state from the earth." However, the Appeals court ruled that the *gob gas* at issue at the Aberdeen mine is "gas" and therefore would be subject to leasing under the MLA – *if it were developed from a gas "deposit."* But, the court said, because the gas is produced by operations conducted by the coal lessee and merely captured by the gas company, gas leasing under the MLA is not appropriate.

Thus, in its decision, the court returned the general issue of ownership of the rights to develop, use and sell CMM to the BLM to resolve. The BLM's authority to permit the capture of CMM *by the coal lessee*, however, is limited to methane released from mining (of federal coal leases), clouding the picture with respect to any pre-mining drainage conducted by a coal mine operator. Further, resolution of coal and gas leases under the BLM depends upon which mineral lease was assigned first. Where the coal lease predates the gas rights within a split estate, the BLM and the coal lessee may enter into a bilateral agreement to amend the coal lease to authorize capture of CMM that would otherwise be vented by MSHA-required ventilation systems. Where the gas lease is senior, precedent set in the Powder River Basin incentivizes the owner of the gas lease to conduct pre-mining drainage of the split estate, but must abandon coal methane development as mining approaches. In either case of rights seniority, if the CMM in question is deemed a gas resource subject to royalty payments by either the coal or the oil and gas lease holder, that lease holder will have to obtain the proper permits from the BLM in order to develop the CMM resource. As with any significant actions on federal lands, this will trigger a requirement for the responsible federal land holder (e.g., the BLM, the Forest Service) to conduct an Environmental Impact Statement under the National Environmental Policy Act.

2.2.2 Challenges to Environmental Impact Statements Addressing Mine and CMM Development

There appears to be a growing trend towards challenging the Draft Environmental Impact Statements (DEIS) required of underground and surface mines operating under federal leases, based on a failure to adequately consider the climate change implications of the methane liberated from the coal. These challenges have yet to result in a requirement that mines control their methane emissions, although it falls under the powers of the BLM to utilize the findings of the EIS to insert such stipulations within a lease contract. Given the heightened focus on climate change over the last year, the future potential for this sort of requirement is real and should be monitored. At least two CMM EIS challenges based on mine methane emissions have been files thus far, both of which involve underground mines in Colorado. The first entails the expansion of both the mining operation and degasification system at the West Elk Mine, which is partially located on Forest Service lands. In this case, a final EIS was accepted in 2007 before it was reversed in early 2008 following a legal challenge which stated that alternatives to emitting the ventilated and

[29] http://www.ibiadecisions.com/Ibla/Ibladecisions/175IBLA/175IBLA008.pdf

drained methane were not considered. The permits for the expansion were granted, however, prompting environmental NGOs to file suit over the potential methane emissions. EPA Region 8 has also written the Forest Service to express its concern over methane venting at the West Elk Mine. A second EIS challenge related to CMM impacts is brewing around the proposed Red Cliff Mine, also in Colorado. The DEIS was released in January 2009 and environmental NGOs have vowed to make sure that the final EIS adequately evaluates and addresses the climate-related impacts of the mine.

2.2.3 Alternative Energy Standards

A number of states have enacted Renewable or Alternative Energy Portfolio Standards, which require that utilities generate a specified amount of electricity from eligible energy sources and technologies. Pennsylvania stands alone in that it's Alternative Energy Portfolio Standard (AEPS) Act of 2004, which mandates an 18 percent alternative energy generation requirement by 2020, includes coal mine methane as a Tier 1 resource.

Similarly, the latest version of the American Clean Energy and Security Act of 2009 (H.R. 2454, as of 15 May) includes coal mine methane as an eligible energy resource for credit towards meeting the 15 percent by 2020 renewable electricity standard.

Although the Pennsylvania requirement and the potential federal requirement do not *require* that utilities use CMM capture to meet the overall standard, the Reserve may wish to consider whether CMM used for electricity generation that receives renewable or alternative energy credits under the PA AEPS, or any future similar law, should be treated as additional.

2.2.4 Greenhouse Gas Reduction Plans

A number of US states have begun to address climate change and GHG emissions through participation in state and/or regional GHG cap and trade programs and the development of GHG reduction action plans. While none of these programs require the capture of drained or vented CMM as a reduction strategy in the coal mining sector, it apparently is under consideration as a reduction strategy. The governor's Climate Change Advisory Committee in Pennsylvania has released a Work Plan for Potential GHG Reduction Measures. The Work Plan is a step within the Committee's requirement, under the Pennsylvania Climate Change Act of 2008, to develop a Climate Change Action Plan to submit to the governor. One of the Committee's draft Reduction Measures, the Coal Mine Methane Recovery Initiative, suggests that the state could "require or encourage longwall mine owners/operators to capture 20% of the methane that is released into the atmosphere during mining operations."[30] Should this or a similar CMM-specific reduction strategy be enacted as legislation or by administrative rule in Pennsylvania or any other state (or federally, see discussion of standards of performance above), covered mines would clearly fail the test of regulatory additionality.

[30] CCAC. 2008. Work Plan for Potential GHG Reduction Measure. At: http://www.depweb.state.pa.us/energy/lib/energy/docs/climatechangeadvcom/industrial/coal_mine_methane_101408.doc

2.2.5 Tax Credits and Other Project Financing Incentives

Beyond rules and regulations, the additionality of offsets is often also assessed with respect to financing – whether a project makes economic sense for the developer to pursue on its own or if it receives government subsidies adequate to make the project economically attractive to undertake. The federal government currently offers production and investment tax credits for a number of renewable energy sources, namely wind and solar, respectively. Such a credit was at one time available for CMM recovery projects. The former incentive provided a tax credit per Btu to the owners/operators of wells recovering CMM. The credit, under Section 29 of the Internal Revenue Code (now Section 45), was created in 1980 and effective from 1992-2002 for wells drilled prior to 1992. The credit had a substantial impact on the growth of CBM production in the 1980s and 1990s. While the credit for CBM and CMM was allowed to expire in 2002, advocates of the credit have repeatedly pushed for its reinstatement.

Some states offer renewable and alternative energy loans, grants, tax credits and deductions of their own. Specifically related to CMM, the Pennsylvania Energy Development Authority Grants and Energy Harvest Grants programs each provide funding for which coal mine methane recovery projects are eligible to apply. The Reserve may wish to consider excluding CMM projects receiving government subsidies from consideration as additional.

Pennsylvania's energy financing programs are run by the state's Department of Environmental Protection (DEP). The Pennsylvania Energy Development Authority (PEDA)[31] issues grants and loan guarantees for alternative energy projects and related research involving a specified list of alternative fuels, including coal mine methane. Under the PEDA Grants program, funds are available through a competitive application process to businesses that develop projects that generate alternative energy or produce alternative fuels, among other innovative advanced energy applications. Funds may be used for the purchase and installation of energy facilities or equipment used for the generation, production or distribution of alternative energy or alternative fuels, as well as for the construction of facilities engaged in alternative energy R&D. The 2009 solicitation involves $21 million in funds that may be awarded in increments of up to $1.5 million for any individual project. Since 2005, the PEDA grant program has awarded $50 million and leveraged an additional $93 million in private financing to assist the implementation of 110 projects across Pennsylvania.[32]

The Energy Harvest Grants program, administered since 2003 by the Office of Energy Technology and Deployment, awarded $7.2 million in project financing in 2009 for its 2008 solicitation. Funds from the Harvest program are meant to support projects that improve air or water quality in Pennsylvania through better management of the state's energy resources in ways that also improve the environment and support economic development. Applicants must quantify the air or water pollutant reduction that will result from implementation of the project. As under the PEDA Grants program, carbon

[31] http://www.depweb.state.pa.us/enintech/cwp/view.asp?a=1415&q=504241
[32] DEP Daily Update, 13 April 2009.
http://www.depweb.state.pa.us/news/cwp/view.asp?a=3&q=545940&pp=12&n=1

dioxide is considered an air pollutant that could be reduced by Harvest Grant projects and coal mine methane and waste coal reclamation for energy use are eligible project categories. The program has funded waste coal-to-diesel and waste coal-fired electricity generation projects in the past, but has yet to finance any CMM projects. As of the 2008 solicitation, for-profit entities are no longer eligible to apply directly for these grants. Businesses with fewer than 100 employees, however, may still apply provided that they have a 501(c)3, county government or agency sponsor. Further, also as of the 2008 announcement, funding through this program is now limited to $500,000 per project.[33]

[33] http://www.depweb.state.pa.us/energy/cwp/view.asp?a=1374&q=483024

3 DEVELOPMENT OF COMMON PRACTICE STANDARDS

With the preceding chapters serving as background, we now turn to the development of common practice standards for use in the Climate Action Reserve's upcoming Coal Mine Methane (CMM) Project Protocol. To structure our analysis, we began by defining three basic types of CMM projects:

- **Methane Drainage and Capture (MDC) Projects.** Projects designed to add both methane drainage and methane capture systems to existing or new mines that have neither;

- **Methane Capture (MC) Projects.** Projects designed to capture and utilize methane for the first time from mines that are already venting gas from existing methane drainage systems; and,

- **Ventilation Air Methane (VAM) Projects.** Projects that implement Ventilation Air Methane Technology (e.g., TFRR and CFRR technology).

Within each of the first two project types, our analysis will separately consider common practice standards for the three types of drainage systems currently used in the U.S.: gob wells, horizontal pre-mining boreholes, and vertical pre-mining boreholes. It should be noted that the distinction we are drawing between MDC and MC projects has important implications for both the common practice standards and for the development of an appropriate emissions baseline. The implications for the common practice standards will become clearer below. However, we would like to briefly summarize the baseline implications here; this discussion should help to clarify the reason why we are distinguishing between these two project types.

Absent an MC project, a mine will continue to vent methane from its drainage system. Thus the emissions that would have occurred, absent the MC project, are the emissions from the *drainage* system. In contrast, the emissions avoided through the implementation of an MDC project would, absent the project, have occurred through the *ventilation* system. This follows from the fact that it is the MDC project itself that results in the installation of the drainage system—absent the project there is no drainage system, and methane that would otherwise have travelled through the drainage system will instead be routed through the mine's ventilation system. Furthermore, in the case of pre-mining drainage in particular, the emissions captured by the MDC project *would not have been emitted through the ventilation system until mining reaches the drainage boreholes*. In other words, there is a delay between the capture and utilization of methane from pre-mining drainage boreholes, and the point in time when this methane would have been emitted through the return air shafts absent the project. This time delay can be lengthy; e.g., it can last for years in cases when vertical pre-mine boreholes are drilled before the mine even opens.

The methane emitted in the baseline for pre-mining MDC projects thus lags the capture of this same methane, potentially necessitating a delay in the awarding of credits to these types of projects. In contrast, there is no time lag between the methane emitted in the baseline and the recovery of this same methane in the case of MC projects, because these projects are capturing methane that would otherwise have been immediately emitted from the drainage boreholes. It is this difference in the timing of the avoided emissions that, we believe, necessitates the distinction between, and separate analysis of, MC and MDC projects.

The data analysis that follows is subdivided into three sections, corresponding to the three CMM project types. We begin with our analysis of the most complex (from a GHG accounting standpoint) of the three types: MDC projects.

3.1 Data Analysis for MDC Projects

Our first set of analyses focused on projects involving the development of a mine drainage system used to route the methane to methane capture and utilization equipment. In the following pages we first develop our initial hypotheses for these project types, and, based on these hypotheses, we conclude that the common practice standard is in fact the performance threshold type best suited to these projects. We then present a brief overview of the results of our analysis supporting both our initial hypotheses and our recommendation of the common practice standard. This is followed by a more detailed documentation of the data, methodology, and results of the data analysis. Finally, this subsection concludes with our development of the specific common practice thresholds recommended for inclusion in the protocol, as well as our recommendations concerning the development of emission baselines for MDC projects.

3.1.1 Our Hypothesis: Federal Health and Safety Regulations Influence Coal Mine Operators' Decisions to Install Methane Drainage Systems

One of the key factors to be assessed when determining the additionality status of an offsets project is the regulatory environment. Using the "regulatory additionality" screen, a project is judged to be non-additional if federal, state or local regulations require the project to be undertaken. As discussed in Chapter 2, there currently exists no federal, state, or local regulations requiring coal mines to reduce, limit, or control their methane emissions. Hence, based solely on a consideration of *emissions* regulations, all coal mine methane projects would appear to pass the regulatory additionality screen.

However, the situation for coal mines is complicated by the existence of federal *safety* regulations that govern methane concentration levels inside the mine. These safety regulations may effectively necessitate the utilization of methane drainage systems under certain gassy conditions. While there is no requirement to *capture* the methane emitted from such systems, to the extent that these systems may be necessitated by the safety regulations they should not be considered a part of an additional coal mine methane project. In other words, the safety regulations may have important implications for where the physical project boundary is drawn. Specifically, the methane drainage system may need to be excluded from the project *if* the system was developed as a response to the safety regulations. In this case the *methane drainage* system does not pass the regulatory additionality screen, although the *methane capture* system does pass this screen; the project boundary must therefore include only the capture system. This effectively means that MDC projects should be treated as if they are MC projects; i.e., even though the methane drainage system is being developed as a necessary part of the methane capture project, the drainage system represents a response to regulations, and as such cannot be considered a component of an additional project. Like MC projects, the project boundary for MDC projects driven in part by the safety regulations must include *only* the methane capture and utilization equipment. In effect, such MDC projects reduce to MC projects.

However, if the drainage system was *not* a response to the safety regulations, but rather was developed in order to capture the methane, then it should be included within the project boundary as a necessary component of the methane capture project. Here the methane drainage system, along with the methane capture system, passes the regulatory additionality screen. Therefore, the key question we need to address, in order to enable us to establish an appropriate project boundary—and, in turn, to enable us to decide whether a project should be treated as an MDC or MC project—is whether or not, and under what conditions, the use of methane drainage is a response to the federal safety regulations. While this question cannot be definitively addressed, an analysis of common practice can help us to infer the most likely answer.

There is in fact a strong argument to be made that, *under some conditions,* methane drainage is a necessary response—or at least a common industry response—to the safety regulations. As previously discussed, methane is explosive when it comprises 5 to 15 percent of the mine atmosphere. Therefore, to ensure that methane remains well below the concentrations at which it becomes explosive, federal regulations require that methane levels be kept below 1 percent at the working face. To help ensure that this requirement is met, all underground mines (gassy and non-gassy) are required to develop ventilation systems that meet detailed specifications laid out in the federal regulations. In contrast, methane drainage is not specifically required under federal regulations for any underground coal mines, regardless of whether they are considered gassy or not. Nonetheless, a small percentage of mines may not be able to rely exclusively on ventilation to meet the <1 percent methane concentration requirement. Specifically, longwall mines operating in gassy conditions release very large quantities of methane, in part because the production rates at these mines are much higher than corresponding rates at room and pillar operations. Diluting the released methane solely through ventilation presents a number of significant, and perhaps insurmountable, difficulties for the former operations:

- The costs of developing and operating the mine ventilation system become excessive, and possibly unsustainable; e.g., mine fan power requirements may result in excessively high electricity bills.

- Even assuming that mining is economically feasible given these additional ventilation costs, moving the large quantities of air needed to dilute the methane across the longwall face may cause excessive amounts of respirable coal dust to be picked up in the resulting high winds. The respirable dust levels to which miners are exposed are limited by federal regulation for health reasons. Thus, attempts to meet the methane safety regulations that rely exclusively on ventilation may in turn put the mine out of compliance with the respirable dust requirements.

It should be noted that whereas the first (cost) problem above would affect a very gassy room and pillar mine as well as a longwall mine, the second (respirable dust) problem is more specific to longwall mines. Due to both the high production rates and the physical layouts of longwalls, exposure to respirable dust is generally a bigger problem on longwall than on room and pillar mines.

Given the above considerations, we hypothesize that the tensions between the methane safety and respirable dust health regulations may either necessitate or at least warrant the use of mine drainage *at longwall mines facing gassy conditions.* We further hypothesize that the higher the methane liberation rate at a particular mine, the more difficult it is to stay in compliance with both the methane and respirable dust requirements, and hence the more likely it is that the use of a mine drainage system is a response to the regulations rather than a voluntary measure.

However, we want to stress that there is no way to know, conclusively, whether the methane drainage system at a particular mine was motivated by the regulations or by the desire to capture the methane. In fact, at many mines it is likely that both factors play a role; motivation is probably more a grey area for those mines falling in between the gassiest mines and the least gassy mines. Whether the mine operator's decision was clearcut or not, their motives for using methane drainage are unknowable to the analyst assessing project additionality. We can at best infer the influence of the regulations on the decision to use methane drainage, through an analysis of the available data relating to common practice.

3.1.2 Recommendation for the Common Practice Standard

The above considerations lead us to conclude that a common practice standard is the type of performance standard that is best-suited to assessing the additionality of coal mine methane projects. As previously discussed, the use of methane drainage is in many cases influenced by regulations governing methane and respirable dust concentrations in the mine atmosphere. Furthermore, coal mine methane projects do not lend themselves to rate- or technology-based comparisons. The difficulty inherent in applying a rate or emissions intensity performance threshold to coal mine methane projects stems from the fact that mine emissions intensities are as much, if not more, a function of geology as of project performance. A mine operating in very gassy geologic conditions could very well adopt methane drainage/capture techniques that go far "above and beyond" business-as-usual, and yet still emit more methane than most other mines given their particularly gassy baseline. To address this problem, a relative measure, such as methane captured as a percent of methane liberated, could perhaps be used in place of emissions intensity as the basis of a performance threshold. However, geology remains a very important determinant of the relative effectiveness of a mine drainage system. For example, two comparable mines using pre-mine vertical boreholes drilled on exactly the same pattern and spacing, could achieve dramatically different methane drainage-to-liberation ratios depending on such factors as the type of rock overlying the coal seams, and the spacing/orientation of fractures in this rock (which can serve as conduits for the movement of the methane to the boreholes). Put simply, the basic problem associated with applying a rate-based measure to a coal mine methane project is that such a metric is likely to prove more a measure of the mine's geologic conditions than the quality of the project's performance.

Furthermore, a rate-based measure—be it absolute or relative—ignores the potential influence of methane concentration and respirable dust regulations on the decision of whether or not to drain the methane. In fact, it is precisely the mines that capture large percentages of the methane liberated, through the use of pre-mine and gob drainage systems, that tend to be the gassiest and that therefore are likely to be most heavily influenced by the health and safety regulations in their decision to adopt pre- and post-mining drainage. (As we shall see in the data analysis section below, the data support this point.) Hence, instead of indicating a project's additionality, a high methane capture ratio might on the contrary indicate that the project is most likely *not* additional but rather a response to the federal regulations.

Nor is a technology standard well-suited to coal mine methane projects. The key technological determinant of the amount of methane captured is the type of drainage system used. (The equipment used to *capture* the methane once it has been drained all have very high capture rates and thus are essentially equivalent from a performance standpoint.) It is certainly true that a mine utilizing both pre-mining and post-mining drainage will, all else being equal, achieve methane capture ratios exceeding those of a mine using only post-mining drainage. Similarly, a mine that employs both horizontal and vertical pre-mine boreholes should, all else equal, capture more methane than a mine using only horizontal boreholes. But once again, the use of more extensive pre-mining methane drainage techniques may be more indicative of a very gassy mine that is being *forced* by federal regulations to go above and beyond the more common post-mining methods.

Hence neither a rate- nor technology-based performance threshold appears well-suited to coal mine methane projects. However, a common practice standard does seem well-suited to these projects, in so far as common practice can help us to infer whether the decision to install a methane drainage system was influenced by the federal health and safety regulations. Specifically, by identifying the conditions under which methane drainage becomes common practice, we can infer that mines operating under these conditions are *probably* (though not definitely) responding to the safety and health regulations. By the same token, mines *not* operating in these same conditions that nonetheless choose to undertake an MDC project are probably doing so for reasons other than meeting the regulatory requirements.

3.1.3 Overview of Analytical Results

Our analyses of the available coal mine data had three overarching goals:

- Test our primary hypothesis that federal methane safety regulations may either necessitate or at least warrant the use of mine drainage *at longwall mines facing gassy conditions.*

- Test our corollary hypothesis, that the higher the methane liberation rate at a particular mine, the more likely it is that the mine's decision to use a methane drainage system is a response to safety and respirable dust regulations.

- Establish the common practices that exist with respect to coal mine methane under various operating conditions.

To meet the above goals, we conducted an analysis to determine the common practices utilized by coal mine operators to dilute methane concentrations, as a function of methane liberation rates. We found that:

- The use of methane drainage is currently limited to gassy longwall mines;

- Over 76 percent of the 34 longwall mines with average methane liberation rates $\geq$ 0.5 billion cubic feet per year utilize drainage systems

- Three of the six longwall mines with methane liberation rates between 0.5 and 1 billion cubic feet per year utilize drainage systems;

- None of the six room and pillar mines with methane liberation rates $\geq$ 0.5 billion cubic feet per year utilize drainage systems; and

- Only two of the 20 (10 percent) longwall mines, and none of the more than 200 room and pillar mines, with methane liberation rates < 0.5 billion cubic feet per year use drainage systems.

The above results clearly indicate that mining method (longwall versus room and pillar) and methane liberation rate are both key determinants of common practice with respect to the use or absence of methane drainage. In particular, the use of drainage systems at 76 percent of the gassiest (liberation rates in excess of 0.5 billion cubic feet per year) longwall mines indicates that, under gassy conditions, methane drainage is a common practice. On the other hand, methane drainage is clearly *not* a common practice (in fact it is non-existent) at room and pillar mines of any liberation rate.

The results *appear* to support our hypotheses, but there is another possible explanation for the observed pattern of methane drainage utilization that needs to be considered. Specifically, it might be argued that the observed relationship between methane liberation rates and the use of methane drainage reflects underlying economic rather than regulatory considerations. It is true that the economics of a methane recovery project will depend heavily on the amount of methane that can be captured. In general, the more methane liberated from a mine, the greater the quantity of methane that can be captured, and hence the more economically feasible a methane capture project becomes. Is it possible that mine operators are being driven by these economic considerations, rather than regulations, in their decision to employ mine drainage systems?

It is a possibility, but we would note that if economics alone were driving the decision process, then all of the mines employing drainage systems would also utilize methane capture. In fact, 39.3 percent of the mines with drainage systems are *not* capturing the methane. Clearly the decision to drain the methane at these mines is not being driven by the economic benefits of capturing the methane.

Turning to the 60.7 percent of mines that *do* both drain and capture the methane, we would expect to find very gassy room and pillar mines in roughly the same proportion as longwall mines. In fact, whereas 69.2 percent of the 26 longwall mines with average annual methane liberation rates in excess of 0.5 billion cubic feet use methane drainage and capture, none of the six room and pillar mines with methane liberation rates $\geq$ 0.5 billion cubic feet per year employ drainage and capture systems. Since the economics of methane capture projects should be similar regardless of mining method, the stark differences in the prevalence of methane drainage systems across mine type suggests that factors other than economics are, at least in part, driving mine operators' decisions. Again, because of their very high production rates and their physical layouts, longwall mines face unique challenges when seeking to meet the federal methane concentration regulations without exceeding federal respirable dust standards. Room and pillar mines, with their lower production rates and ability to limit the placement of production personnel in return air passageways, can rely exclusively on ventilation to meet their methane dilution requirements without exceeding respirable dust limits. The data thus suggests that while the economics of methane capture may be a factor in determining the use of methane drainage at very gassy mines, federal regulations—and in particular the interplay between the methane concentration and the respirable dust regulations—are also an important determinant of drainage utilization.[34]

In the following pages our data analyses, and the results of these analyses, are documented in greater detail. Following this documentation, and based upon the analytical results, we establish common practice standards for MDC projects.

3.1.4 Data Used and Data Pre-Processing

The primary database used for our analysis was the methane emissions database provided to us by EPA (in the spreadsheet "Coal 07 draft"). This spreadsheet provides annual emissions-related data for underground mines classified as gassy by the Mine Safety and Health Administration (MSHA); the data cover the period 1990 through 2007. The emissions data contained in this spreadsheet are used as the basis for the coal mine

[34] It should be emphasized that this analysis is based on a consideration of the economics of the methane drainage and capture project in isolation from the economics of mining. Methane drainage will significantly affect the economics of the mining process, by reducing ventilation costs. However, because it is the federal safety regulations that ultimately drive ventilation requirements, the use of drainage as a means to improve ventilation and mining economics can best be understood as a response to the underlying regulatory requirements.

methane emissions estimates published in EPA's annual *Inventory of U.S. Greenhouse Gas Emissions and Sinks* reports.[35] For the purposes of our analysis, we used the annual data provided by this spreadsheet for the 2000-07 timeframe, covering a total of 295 gassy underground mines. Some of these 295 mines were in operation throughout the 2000-07 timeframe, while others were producing for only part of the period. In addition to detailed information on the subset of mines using methane capture, the spreadsheet provides the following general data:

- Company name, mine name, and Mine Safety and Health Administration (MSHA) ID number;
- State and county in which each mine is located;
- Daily average and total methane emissions from the ventilation system, as well as the total amount of methane liberated by the mine (equal to the sum of the ventilation emissions and the drainage emissions or capture);
- An indication of whether the mine utilizes a degasification system, and if so, a brief description of the system and the total amount of methane drained through the system; and
- An indication as to whether the drained methane is captured, and a brief description of how the captured methane is utilized.

Additional information on the EPA data, including original sources of the data and measurement or estimation methodologies used to develop the data, are provided in the appendix to this report.

To supplement this primary data set, EPA provided us with a second database containing annual coal production data for the gassy mines, for the years 2002 through 2006, along with an indication of the mine's production status.[36] We supplemented this data with mine-level production data for 2000, 2001, and 2007, obtained from the Energy Information Administration (EIA). [37] SAIC merged the production data with the emissions database using each mine's unique MSHA ID number (included in both databases). The final merged data set includes 241 mines for which emissions data for at least one of the eight years in the 2000-07 timeframe is available.

Finally, a list of U.S. longwall mines producing in excess of 750,000 tons of coal from January through September 2007, published by CoalUSA magazine, was provided by EPA; this list was supplemented by SAIC with similar CoalUSA lists for production from 2001 through 2006.[38] A similar CoalUSA table detailing the production of top non-

[35] See, for example, US EPA, *US Inventory of Greenhouse Gas Emissions and Sinks: 1990-2007*, 2008.
[36] The Energy Information Administration (EIA) was the original source of the production data.
[37] EIA, http://www.eia.doe.gov/cneaf/coal/page/database.html.
[38] Weir International, Inc. 2008. "US Longwall Mines – Production and Productivity: September 2007 Year to Date (Mines Producing in Excess of 750,000 tons through September)." *CoalUSA*, March 2008; Weir

longwall mines in 2007 was also referenced.[39] Further, we consulted the mining method information contained in two EPA reports on methane recovery opportunities at gassy mines.[40] SAIC combined the mines on these lists to create a master list of longwall mines in operation during the 2000-07 time period. Assuming (1) that the individual lists provide a comprehensive identification of all longwall mines falling above the production cutoff; (2) that most if not all longwall mines would meet the production cutoff when operating at full capacity; and (3) that most if not all longwall mines would have operated at full capacity at least in one year during the 2000-07 time period, then the master list developed by SAIC should represent a reasonably comprehensive list of longwall mines operating in and around 2007. Therefore, using the master list, SAIC identified all of the mines in the merged emissions/production database that use the longwall method. All remaining mines were assigned to the room and pillar method (the other main underground coal mining method). In keeping with the industry standard definition, any mine having at least one longwall face or that opened a longwall face at some point during the 2000-2007 period was treated as a longwall mine.

In reviewing the merged dataset, we found that in a number of cases the information identifying the drainage system type or methane utilization project in use in some years during the 2000-07 timeframe was missing. When the missing information was provided in other years, we extrapolated the drainage system type information for the years these data were available to the years with missing information. (For example, if the database indicated that a mine used gob wells only in 2004, 2005, and 2007, but failed to provide information on the type of drainage system in use in 2006, we assumed exclusive reliance on gob wells in that year as well.) In other cases our professional judgment was used to fully specify incomplete information provided in the database. For example, in a few cases the drainage system was reported as being "vertical boreholes with pumps" exclusively. Although the database, in these few cases, failed to specify whether the boreholes are pre-mining or gob boreholes, we assumed they were the latter because (1) pumps are normally used in conjunction with gob, not pre-mining, wells, and (2) based on the complete data provided for the vast majority of the mines vertical pre-mining wells are never used alone, whereas gob wells are frequently used exclusive of other drainage borehole types.

International, Inc. 2006. "United States Longwall Mining Statistics: 1996-July 2006." Table 2: 2006 June Year to Date US Longwall Mine Production and Productivity; "Table: US Longwall Production 2005," *International Longwall News*, 27 March, 2006. At: http://www.longwalls.com/sectionstory.asp?SourceID=s50; NIOSH, 2005. "Table: US Longwall production 2004." *International Longwall News*, 23 March 2005; NIOSH, 2004. "Table: US Longwall output 2003 now working." *International Longwall News*, 7 April 2004; NIOSH, 2003. "Table: US Longwall output 2002." *International Longwall News*, 21 July 2003.

[39] Weir International, Inc. 2008. "Top 50 US Underground Mines (non-longwall) – Production and Productivity: September 2007 Year to Date." *CoalUSA*, March 2008. *CoalUSA*, March 2008.

[40] U.S. EPA, *Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 1999-2003*, EPA 430-K-04-003, 2005; and U.S. EPA., *Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 2002-2006*, EPA 430-K-04-003, 2008.

Finally, we identified a few situations in which the drainage system type and utilization project type reported in EPA's two published reports profiling gassy underground mines differed from the system and project types shown in the database.[41] In these cases we gave preference to the information provided in the reports, under the assumption that a published report is more likely to have the correct information than an unpublished database used for EPA's internal purposes.

In combining and using the data for eight separate years into a single dataset, we characterized each mine according to the furthest development of its drainage system. For example, if a mine used gob boreholes only in some years, but gob boreholes with horizontal pre-mining boreholes in other years, we treated the mine as using both drainage system types during the 2000-07 timeframe. Similarly, mines that utilized methane in some years but not in others were treated as having utilization projects in operation in the 2000-07 timeframe. Our decision to use and combine data for the past eight years into a single dataset was based on the trend analyses presented in Chapter 1, which indicated that industry practice with respect to drainage systems and utilization projects has remained fairly stable since 2000 (see, e.g., Table 2 in Chapter 1). Given this relative stability in coal industry practices, it appeared safe to combine recent data with older data for the purpose of ascertaining current common practice.

3.1.5 Documentation of Data Analysis

As a first step in our data analysis, we computed arithmetic averages of the annual methane liberation data for each mine in the merged emissions dataset. For example, to compute the arithmetic average for a mine with total methane liberation data for 2002 through 2004, we summed the annual methane liberation values across these years and divided the resulting total by three. We then classified each mine according to its average annual methane liberation quantity. Figure 14, included below, is a histogram showing the number of longwall mines falling within the selected methane liberation categories. This histogram indicates that the use of methane drainage is highly correlated with the quantity of methane produced by a longwall mine. Figure 14 appears to indicate three natural groupings of mines delineated based upon the prevalence or absence of mine drainage systems. The first group, consisting of mines liberating an average of at least 3 billion cubic feet of methane per year, relies very heavily on methane drainage. In fact all of the 15 mines (100 percent) falling in this group use methane drainage systems; clearly methane drainage can be considered a common practice for these very gassy longwall mines.

The data are less clear cut for the second group, consisting of longwall mines producing between 0.5 and 3 billion cubic feet of methane per year. However, the majority of the mines in this group (11 out of 19, or 57.9 percent) use drainage systems. For this group, we might tentatively conclude that the use of methane drainage is less a necessary consequence of the federal health and safety regulations, and more a voluntary response.

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[41] U.S. EPA, *Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 1999-2003*, EPA 430-K-04-003, 2005; and U.S. EPA., *Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 2002-2006*, EPA 430-K-04-003, 2008.

Finally, only two of the 20 longwall mines with annual methane liberation below 0.5 billion cubic feet use drainage systems.[42] Clearly, methane drainage is neither a necessary response to the regulations nor a common industry practice for the least gassy longwalls.

Figure 14 - Histogram of Drainage System Usage by Longwall Mines

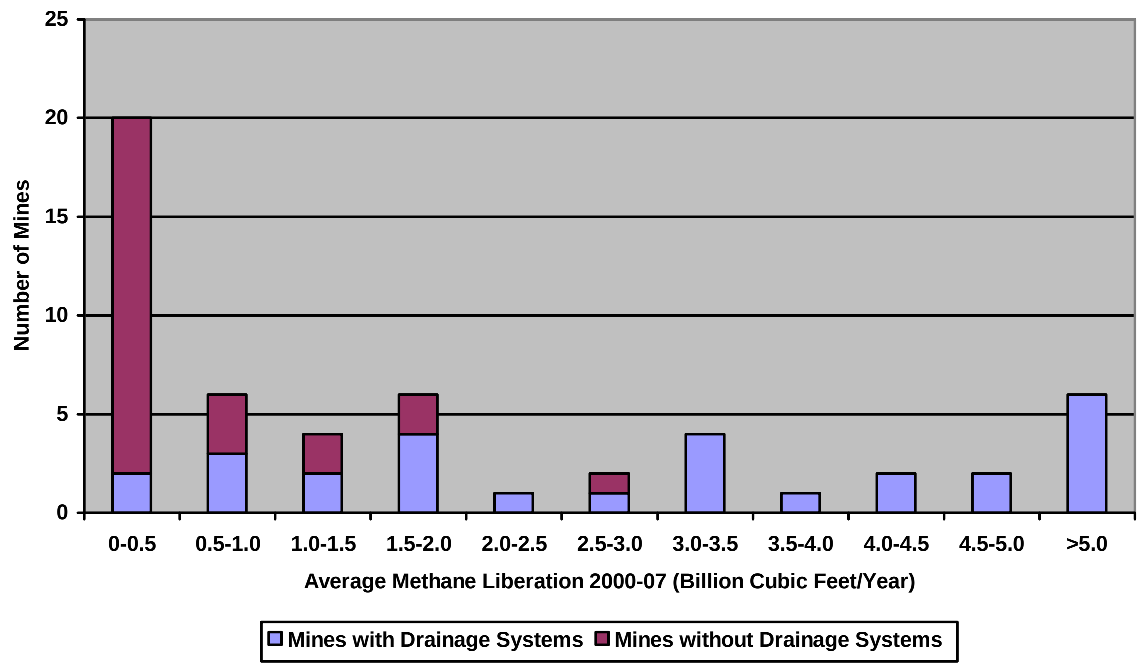
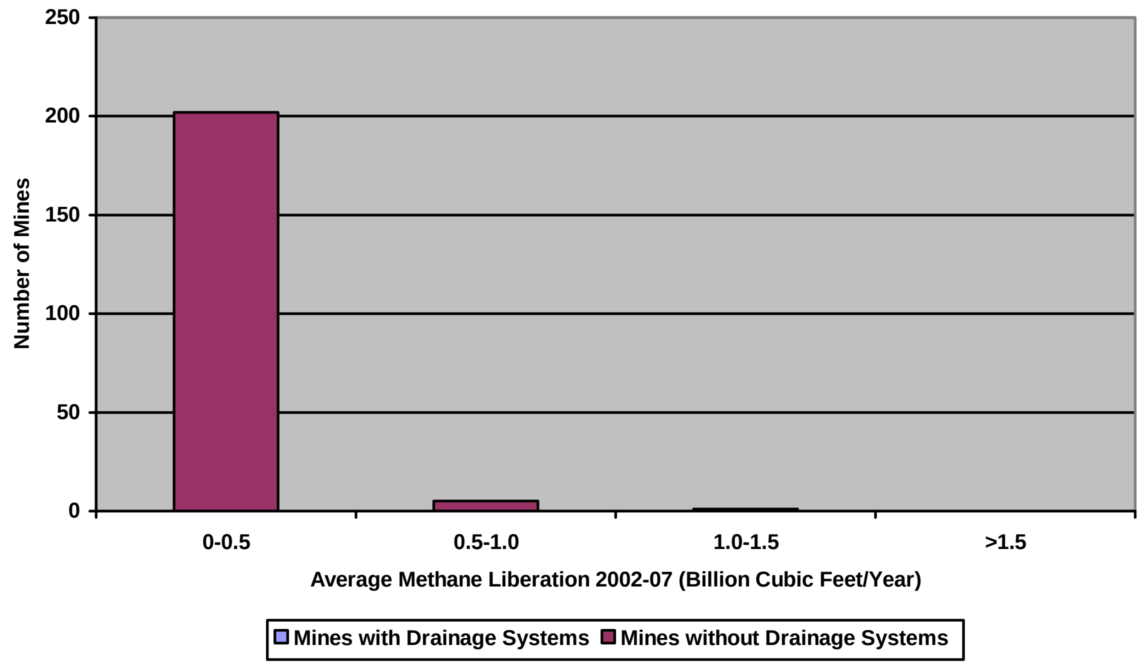


Figure 15 presents a similar histogram for room and pillar mines. As this figure indicates, none of the room and pillar mines in the dataset use drainage systems. While this may be explained in part by the fact that the room and pillar mines tend to be less gassy than the longwalls, note that none of the six room and pillar operations with methane liberation ranging from 0.5 to 1.5 billion cubic feet per year utilized methane drainage. In contrast, five of the ten longwalls falling in this same range of methane liberation relied on drainage systems. Based on this finding, it appears that methane drainage should not be considered a common practice among room and pillar mines, regardless of the amount of gas liberated by these mines. As hypothesized, methane drainage appears to be necessitated by the regulations only in the case of longwall mines operating in very gassy conditions.

[42] It should be noted that the two mines with drainage systems in this category would remain in the minority even if this category were to be more finely subdivided. One of the two mines had an average annual methane liberation of 0.283 billion tons—there are four other mines in the <0.5 billion cubic foot category with methane liberation in excess of 0.283 billion tons that do *not* use methane drainage. The other mine employing drainage liberated 0.128 billion tons of methane per year—there are eleven other mines in the <0.5 billion cubic foot category with methane liberation in excess of 0.128 billion tons, only one of which utilizes methane drainage. Hence there is no way to subdivide the <0.5 billion cubic foot category into subcategories in which mines with drainage systems predominate.

Figure 15 - Histogram of Drainage System Usage by Room and Pillar Mines



Analysis Using Normalized Methane Liberation Data

The above analysis must be considered a preliminary one, in that it relies exclusively on arithmetic average emissions data. A mine's methane emissions depend heavily on its production rate, as it is the process of removing the coal from the seam that relieves the pressure on the nearby unmined coal and surrounding strata, thereby releasing much of the gas. For this reason, the use of arithmetic average emissions data can lead to distorted results, particularly for mines that were underutilized during all or part of the 2000-08 timeframe. Longwall mines that were operating below capacity in one or more years likely experienced reduced methane liberation rates in that year(s)—a factor which may account for some drainage system utilization associated with less gassy (0.5 to 2 billion cubic-foot) mines in Figure 14. To correct for this possibility, SAIC developed normalized methane liberation rate estimates for the mines in the merged database for which both liberation and production data were available. Specifically, for each mine we divided the sum of the 2000 through 2007 methane liberation data by the sum of the mine's 2000 through 2007 production to derive average methane liberation per ton of coal produced. We then multiplied this methane liberation rate by the *largest* of the eight annual production data points in the 2000-07 timeframe to obtain our estimate of normalized methane liberation for the period. The year with the largest production value was used in the calculation in order to increase the likelihood that the resulting methane liberation estimate represents the mine's annual liberation rate when it is operating at full capacity. A mine operator will decide on whether or not methane drainage must be used to meet the regulatory requirements based on the expected methane liberation rate under full capacity operations.[43] Hence it is the methane liberation rate at full capacity that governs the mine operator's decision process; by computing a weighted average methane liberation value for the year in which production reaches its maximum we likewise sought to base our analysis on full capacity conditions. We used a production-normalized average rather than the actual methane liberation observed in the selected "maximum production year" because, as previously noted, the amount of methane liberated can fluctuate significantly from year to year depending on the geologic conditions encountered in each year. By using an average rather than an actual methane liberation value we reduced the potential for distortions introduced by abnormally low or high methane liberation rates in any given year.

It should be noted that production data was lacking for seven of the mines in the merged database; these mines were deleted from the database prior to proceeding with further analysis. Six of the deleted mines were room and pillar operations and hence were not a primary focus of our analysis. The single longwall mine lacking production data does not employ a drainage system.

Figure 16 below presents a histogram of drainage system usage for the longwall mines, based on the production-normalized annual methane liberation rates for the 2000-07 timeframe. In general, these results tend to confirm the results we obtained using the arithmetic average methane liberation data (see Figure 14), with drainage systems still prevalent at the gassiest mines and rare at the least gassy mines. However, Figure 16 does suggest that the area where drainage system usage is relatively uncommon may be wider (≤1.5 billion cubic feet) than the 0 to 0.5 billion cubic-foot band suggested by Figure 14. Within this area, only 5 of the 27 longwall mines (18.5 percent) utilize methane drainage systems. Furthermore, the "grey area," within which mines using drainage systems are in the majority but not to the exclusion of mines relying solely on ventilation, has narrowed from 0.5 to 3 billion cubic feet (see Figure 14) to 1.5 to 3 billion cubic feet. Above a production-normalized methane liberation rate of 3 billion cubic feet per year all of the mines use methane drainage.

Figure 17 presents the drainage system histogram for room and pillar mines based on their estimated normalized methane liberation rate. This figure confirms and reinforces the conclusions drawn on the basis of the arithmetic average data—namely, the use of methane drainage appears dependent not only on methane liberation amounts but on mining method. Whereas six of the 28 longwall mines with production-normalized methane liberation ≤2 billion cubic feet per year use methane drainage, none of the 202 room and pillar mines falling in this same methane liberation range employ drainage systems. Clearly methane drainage is not a common practice at room and pillar mines, regardless of methane liberation quantities.

[43] If the operator were to use a methane liberation estimate based on anything less than full capacity production for the purposes of deciding on the need for a drainage system, the mine would run the risk of being unable to meet the regulatory requirements when operating at full capacity.

Figure 16 - Histogram of Drainage System Usage by Longwall Mines Based on Production-Normalized Annual Methane Liberation in the 2000-07 Period

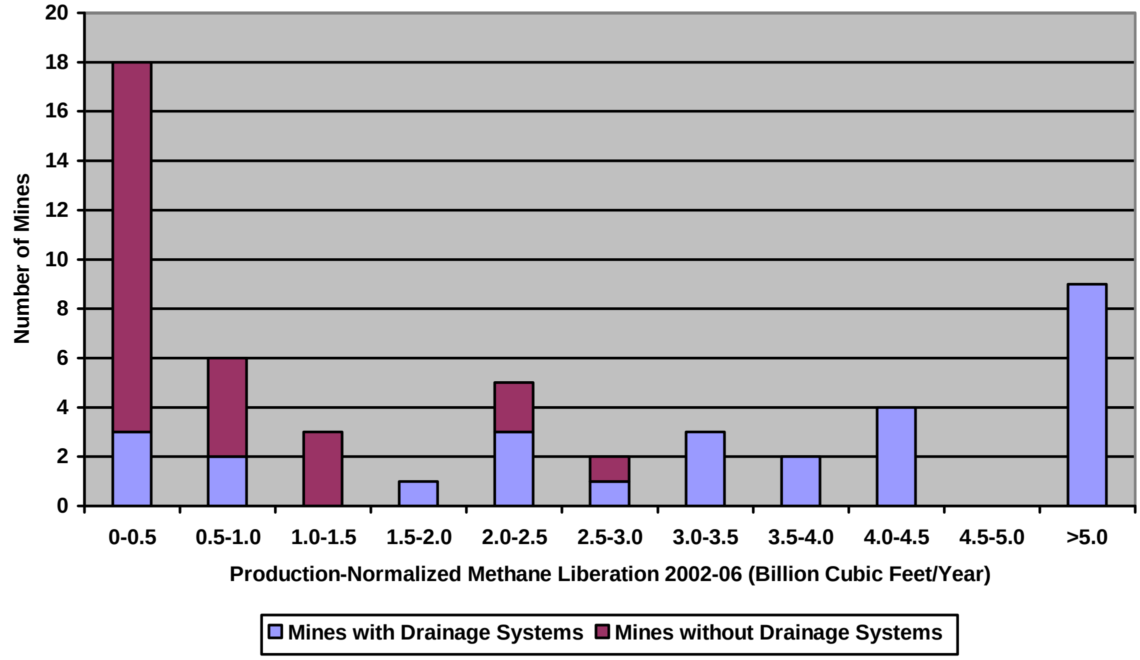
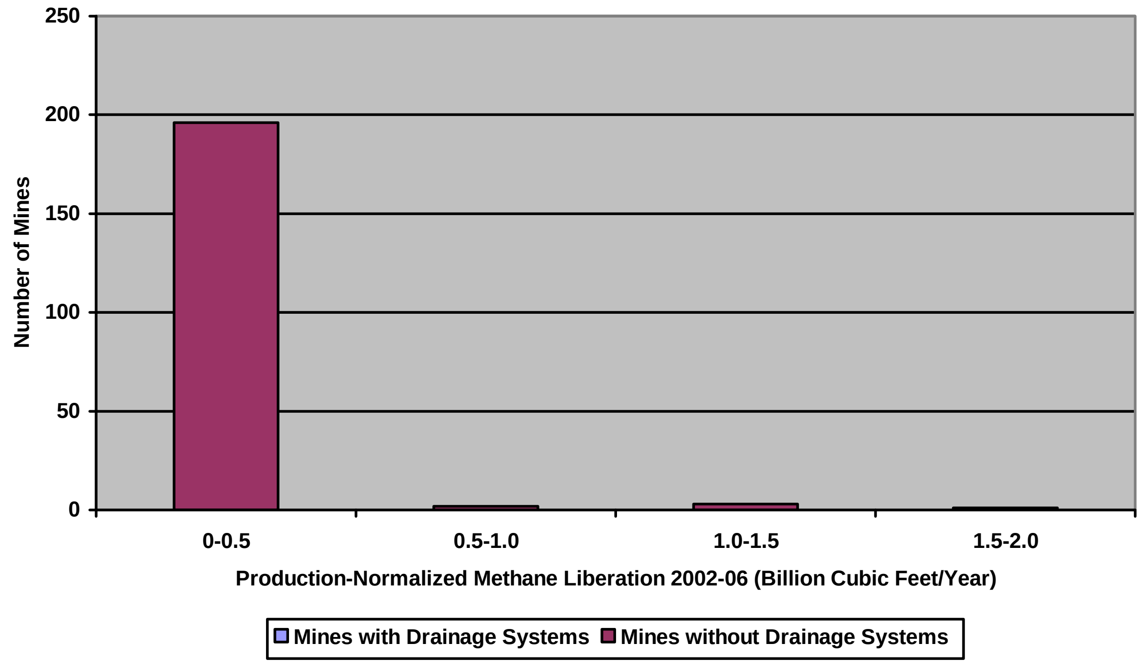


Figure 17 - Histogram of Drainage System Usage by Room and Pillar Mines Based on Production-Normalized Annual Methane Liberation in the 2000-07 Period



It should be emphasized that the above conclusions are necessarily limited by the available data. There are no room and pillar mines with either arithmetic average or production-normalized methane liberation quantities in excess of 2 billion cubic feet. If such very gassy room and pillar mines existed, we might find that some or all of them used drainage systems. However, within the limits imposed by the U.S. mine population we are safe in concluding that the use of methane drainage is a common practice, and a possible if not likely response to the federal regulations, only among longwall mines operating in relatively gassy conditions.

Regional Analysis

Do the above national-level results hold for the different regions of the country, or are there important differences in common practice across different regions? Given our hypothesis, that common practice with respect to methane drainage is being driven in large part by *federal* regulations on health and safety, we would not expect to see major differences across different regions. And to the extent that the small population of gassy longwall mines can support a regional-level analysis, this analysis for the most part confirms our expectations.

To perform the regional analysis, we subdivided the longwall mine population into operations with production-normalized methane liberation in excess of 1.5 billion cubic feet, and less than 1.5 billion cubic feet. The decision to use 1.5 billion cubic feet as the threshold was based on a review of Figure 16, which indicates that drainage systems first become predominant (i.e., in use at the majority of all longwalls) as the 1.5 billion cubic foot mark is crossed (none of the three longwalls operating in the 1 to 1.5 billion cubic-foot range use drainage systems, while the single longwall in the 1.5 to 2 billion cubic-foot category does use drainage).

Table 6 presents an analysis of the regional prevalence of drainage systems at longwall mines falling above and below the 1.5 billion cubic-foot threshold. As this table indicates, at the gassiest (>1.5 billion cubic feet per year) longwall operations methane drainage is found in similar proportions east and west of the Mississippi (86 percent of eastern mines and 100 percent of western mines use drainage). Although the population size is too small to support robust conclusions at the sub-region or state level, we can nonetheless note that, with the single exception of Illinois, at least 80 percent of the gassiest mines in each state use methane drainage. Illinois has only one mine in this category, and hence separate conclusions for the Midwest cannot be drawn. In general, the lack of regional differences in common practice among these gassier mines lends further support to our hypothesis that federal regulations are the key driver in the decision to use drainage systems. Were economics a more important determinant, we would expect to find greater regional diversity reflecting differences in the regional geology and economics.

The results are less clear in the case of the less gassy mines (<1.5 billion cubic feet per year). While only two of the seventeen less gassy eastern mines use drainage systems, 30 percent of the western operations use such systems. Given that we have a population of only ten mines in the West, considerable caution must be used in drawing any conclusions based on these results. That said, the observed regional differences may perhaps suggest that, among the less gassy operations, economics rather than regulations are a more important determinant of whether or not to employ drainage techniques. Again, this would tend to support our general hypothesis, that drainage is a necessity at the gassier mines and a choice at the less gassy operations.

Table 6 - Regional Analysis of Methane Drainage Use Among Gassy Longwall Mines

State/Region	Mines with Normalized Methane Liberation >1.5 Billion ft^3			Mines with Normalized Methane Liberation $\leq$1.5 Billion ft^3		
	Total Number of Mines	Number with Drainage	Percent with Drainage	Total Number of Mines	Number with Drainage	Percent with Drainage
Pennsylvania	5	4	80	2	1	50
Ohio	0	0	NA	2	0	0
W. Virginia	7	7	100	6	0	0
Virginia	2	2	100	0	0	NA
Kentucky	0	0	NA	4	1	25
Alabama	6	5	83	0	0	NA
Illinois	1	0	0	3	0	0
Eastern U.S.	**21**	**18**	**86**	**17**	**2**	**12**
Colorado	3	3	100	5	2	40
Utah	1	1	100	5	1	20
New Mexico	1	1	100	0	0	NA
Western U.S.	**5**	**5**	**100**	**10**	**3**	**30**
Total U.S.	**26**	**23**	**88**	**27**	**5**	**19**

Based on the above analysis, we do not recommend the development of separate common practice standards for the eastern and the western U.S. Clearly separate standards are not warranted for the gassier (>1.5 billion cubic foot) longwall operations. While the situation is less clear cut for the less gassy mines, there are three factors that we believe warrant against the treatment of methane drainage as a common practice in the West but not in the East:

- The population size for the west (ten mines) is probably too small to support the judgment that what we are observing is a regional distinction and not a small sample anomaly.

- To the extent that what we are observing *is* a regional distinction, it is, as argued above, likely driven by economics rather than regulations. Hence even if less gassy western longwalls are more likely to employ drainage systems than are their eastern counterparts, we cannot conclude from this that the western longwalls fail the regulatory additionality test (although they might perhaps be more likely to fail a financial additionality test).

- Given that only 30 percent of the western longwalls use drainage systems, the evidence that this is a common practice is in any event weak.

Rather than making a distinction between eastern and western longwalls, applicable only to the less gassy operations, we instead recommend the development of a single set of national common practice standards. We will return to the issue of defining these national standards shortly, but in order to refine the standards it is first necessary to consider the drainage system type information provided by the emissions database.

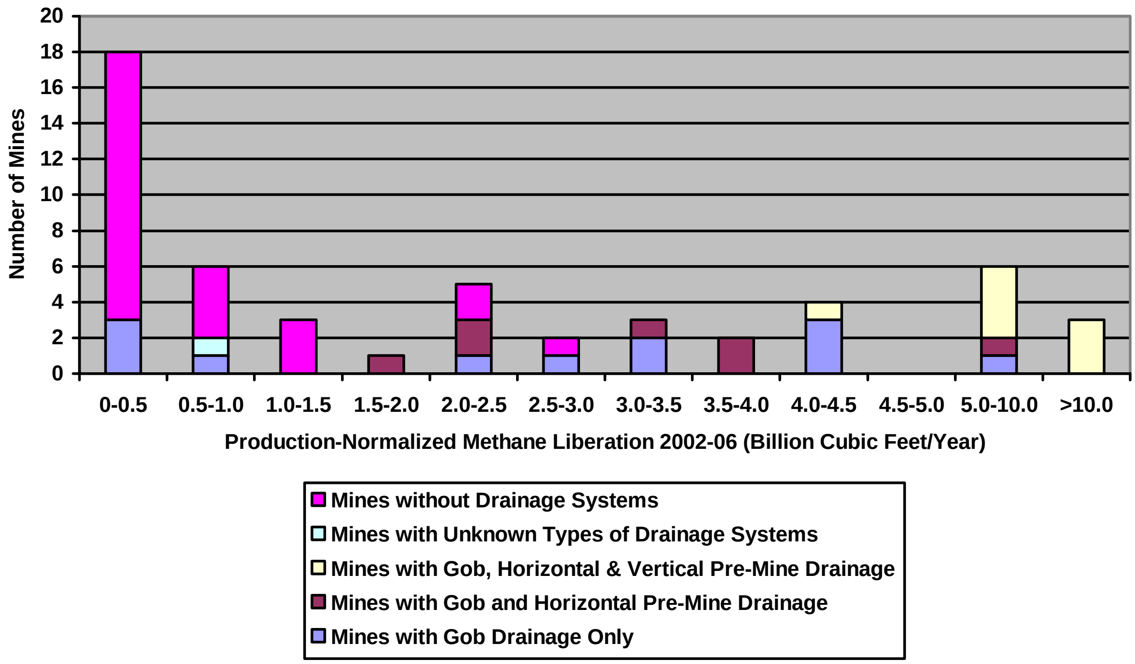
Analysis of Types of Drainage Systems in Use

Figure 18 is a histogram showing the types of drainage systems in use among longwall mines, again as a function of normalized annual methane liberation in the 2000-07 timeframe. As mentioned previously, the database did not always indicate that the drainage system in use at each mine remained the same across the 2000-07 timeframe. While for most mines the notes provided on the type of drainage system in use remained the same in each year, in some cases the drainage system notes changed across years. For purposes of developing the histogram in Figure 18, we selected the *most elaborate drainage system* in use at any given mine during the 2000-07 as being representative of that mine's drainage system for the entire period. For example, if the file indicated that a mine was using gob drainage only during 2002-04, but gob drainage and horizontal pre-mining drainage in subsequent years, it was counted as having both gob and horizontal pre-mining drainage in Figure 18. Similarly, if the file indicated that a mine did not have any drainage system in 2002, but that it had a gob drainage system in 2003-07, we counted the mine in the "gob drainage only" category in Figure 18. We based Figure 18 on the most elaborate drainage system in use at each mine over the 2000-07 timeframe in recognition of the fact that, at some mines, the components of a drainage system may be installed separately over a number of years rather than all at the same time. Furthermore, some mines may gear the drainage techniques used to the specific mining conditions encountered in each year; e.g., relying primarily on gob drainage and utilizing pre-mining drainage only when particularly gassy conditions are encountered. Since our goal in this analysis was to attempt to determine, on the basis of common practice, the *full* range of drainage techniques required to meet the federal safety regulations, we sought to identify and classify each mine's drainage system at its most elaborate stage of development.

As the figure indicates, post-mining or gob drainage comprises at least part of the drainage system at *all* mines utilizing such systems. Gob drainage is generally accomplished using vertical boreholes with pumps; there are, however, at least two mines that use horizontal as well as vertical gob boreholes (in some cases the orientation of the gob boreholes is not specified in the file).

The number of operations that add pre-mining drainage to their gob systems is relatively limited. Of the fifteen mines that use pre-mining drainage, eight combine horizontal with vertical pre-mine boreholes while the remaining seven rely exclusively on horizontal boreholes. Of the latter seven mines, six have production-normalized methane liberation rates falling in the 1.5 to 4 billion cubic feet per year range (the remaining mine falls in the 5 to 10 billion cubic foot per year category). As the figure indicates, pre-mining drainage using vertical boreholes becomes a relatively common practice only at elevated methane liberation levels of at least 5 billion cubic feet per year.

Figure 18 - Histogram Showing Types of Drainage Systems in Use at Longwall Mines as a Function of Normalized Annual Methane Liberation in the 2000-07 Period



Thus Figure 18 reveals a clear progression, from exclusive reliance on gob drainage at the less gassy operations, to the additional use of first horizontal, and then vertical, pre-mining boreholes as the amount of methane liberated increases.

3.1.6 Recommended Common Practice Standards for MDC Projects

Based on the preceding analyses, we can now establish *tentative* common practice standards for Methane Drainage and Capture (MDC) project types. We wish to stress that the standards presented below are our *tentative* recommendations, based on the analyses documented above. These recommendations will be subjected to further evaluation, some adjustment, and finalization, in the next chapter.

First, we tentatively recommend that, for room and pillar mines, *all* MDC projects be accepted as additional, given that such projects are currently non-existent at room and pillar operations.

Based on Figure 16, a common practice threshold of 1.5 billion cubic feet per year suggests itself, with MDC projects at longwall mines liberating less than this amount of methane being accepted as uncommon and therefore additional. However, before accepting such a threshold, it is worth considering why the five mines *with* drainage systems that fall below the threshold are using drainage. None of these five mines are in fact capturing and utilizing their CMM, which strongly indicates that safety, not environmental or economic, concerns motivated their decision to install drainage systems. Clearly, the drainage systems at these mines should not be considered within the boundary of an additional project, and their presence in the group of mines that falls below the 1.5 billion cubic foot threshold raises questions as to whether this threshold is adequate to the task of screening out non-additional projects. In other words, while the use of drainage systems at mines liberating less than 1.5 billion cubic feet per year is uncommon, the evidence suggests that when such systems *are* used they invariably fail to meet standard additionality criteria. For this reason a tighter threshold is recommended. In order to screen out the five mines with drainage systems, a much lower threshold of 0.25 billion cubic feet of methane is required. Therefore, we recommend that *all* MDC projects at longwall mines (defined as any mine that includes at least one longwall production unit) with estimated methane liberation rates below 0.25 billion cubic feet per year be accepted as exceeding common practice. We further recommend:

- Projects employing *pre-mining boreholes (horizontal and/or vertical)* be accepted as exceeding common practice at longwall mines with annual estimated methane liberation between 0.25 and 1.5 billion cubic feet per year. This recommendation is based on the finding that none of the twenty-two mines falling within this range currently use either horizontal or vertical pre-mining boreholes. Any *gob* boreholes included in such projects should be treated as non-additional under the common practice standard; only the pre-mining boreholes should qualify as uncommon.

- Projects employing *vertical pre-mining boreholes only* be accepted as exceeding common practice at mines with annual estimated methane liberation between 1.5 and 4.5 billion cubic feet per year. Only one of the seventeen mines (5.9 percent) falling within this range currently use vertical pre-mining boreholes, thus warranting a finding that use of this drainage system type is not a common practice under these conditions.[44] Any *gob* or *horizontal pre-mining* boreholes included in such projects should be treated as non-additional under the common practice standard; only the vertical pre-mining boreholes should qualify as uncommon.

- Use of *gob drainage* at longwalls with annual estimated methane liberation in excess of 0.25 billion cubic feet per year be treated as Methane Capture (MC) projects and be evaluated as per the rules laid out for such projects in the next section. This recommendation is based on the finding that 26 of the 42 mines (61.9 percent) falling in this category currently use gob drainage (i.e., gob drainage at these mines is common practice). By treating the gob drainage portion of MDC projects as MC projects, we are in effect drawing the project boundary in such a way as to *exclude* the gob drainage boreholes from the project, based on our inference that these boreholes are being drilled as a response to the federal health and safety regulations. However, the *methane capture* portion of

- [44] Furthermore, the single mine that does use vertical pre-mining boreholes also captures and utilizes the methane, indicating that installation of the drainage system was not necessarily motivated exclusively or primarily by the MSHA requirements.

the gob drainage project may still qualify as an offset project (depending on the application of the rules set out in the next section), since the federal regulations in no way require that the methane drained from the seam be captured and utilized—venting the methane is entirely acceptable under the regulations.

- Use of *pre-mining horizontal drainage* at longwalls with annual estimated methane liberation greater than 1.5 billion cubic feet per year be treated as Methane Capture (MC) projects and be evaluated as per the rules laid out for such projects in the next section. This recommendation is based on the finding (from Figure 18) that fourteen of the twenty six mines (53.8 percent) falling in this category currently use horizontal pre-mining boreholes (i.e., use of horizontal pre-mining boreholes at these mines is a common practice). By treating the horizontal pre-mining drainage portion of MDC projects as MC projects, we are in effect drawing the project boundary in such a way as to *exclude* these boreholes from the project, based on our inference that they are being drilled as a response to the federal health and safety regulations.

- Use of *pre-mining vertical drainage* at longwalls with annual estimated methane liberation that exceeds 4.5 billion cubic feet per year be treated as Methane Capture (MC) projects and be evaluated as per the rules laid out for such projects in the next section. This recommendation is based on the finding (from Figure 18) that seven of the nine mines (77.8 percent) falling in this category currently use vertical pre-mining boreholes (i.e., use of vertical pre-mining boreholes at these mines is a common practice). By treating the vertical pre-mining drainage portion of MDC projects as MC projects, we are in effect drawing the project boundary in such a way as to *exclude* these boreholes from the project, based on our inference that they are being drilled as a response to the federal health and safety regulations.

Potential alternative approaches mine operators might follow to estimate their methane liberation rate, for purposes of comparison with the threshold, are presented in Chapter 4.

The application of the above rules in effect involves breaking the MDC project down into four separate components—the gob boreholes, the horizontal pre-mining boreholes, the vertical pre-mining boreholes, and the methane capture equipment—and applying a common practice standard to each component. Depending on the result, the project boundary may be drawn to include (1) the methane capture equipment only; (2) the methane capture equipment and the vertical pre-mining boreholes; (3) the methane capture equipment and the horizontal and vertical pre-mining boreholes; or (4) the methane capture equipment and all of the boreholes (gob and pre-mining). MDC projects with boundaries drawn to include some, or all, of the drainage boreholes must also include the ventilation shafts within the project boundaries, because the use of drainage boreholes will affect (reduce) the amount of methane emitted through the shafts. However, MDC projects that are to be treated as MC projects (i.e., as excluding all drainage boreholes) should exclude the ventilation shafts, as the choice between capturing or venting the emissions from the boreholes will have no effect on ventilation emissions. It should be noted that the inclusion or exclusion of the ventilation shafts within the project boundary will in turn determine the timing of when methane captured from the drainage system may be counted as emission reductions. Specifically, if the ventilation shafts are included in the project boundary, then the emissions captured from the drainage boreholes represent emissions that otherwise would have occurred through the ventilation shafts during the mining process. However, because the methane captured from *pre-mining* boreholes in particular can be captured *years* before this same methane would otherwise have been released through the ventilation shafts, it will be necessary to delay the timing of the crediting of emission reductions to projects that include both pre-mining boreholes and ventilation shafts within the project boundary. On the other hand, projects that, on the basis of the common practice standards established above, should not include the ventilation shafts within the project boundaries may be credited with emission reductions as the methane is captured; i.e., there need and should be no delay between capturing and crediting the methane at such projects.

3.2 Data Analysis for MC Projects

Methane Capture (MC) projects are defined as projects designed to capture and utilize methane for the first time from mines that are already venting gas from existing methane drainage systems. In addition, based on the common practice standards established above for MDC projects, we note that these projects will, in some cases, effectively reduce to MC projects for purposes of determining whether or not the projects qualify.

3.2.1 Recommendation for the Common Practice Standard for MC Projects

As was the case for MDC project types, we recommend the application of the common practice standard as the performance standard type best-suited to MC projects. Like MDC projects, MC projects do not lend themselves to rate- or technology-based comparisons. In general, all MC projects are characterized by a very high rate of capture (essentially 100 percent[45]), making it difficult to distinguish projects on the basis of a metric such as methane captured as a percentage of methane drained. In fact the "Coal 07 draft" data appears to assume that, for mines employing methane capture, all of the methane drained is captured and used (albeit some of the captured methane is used to run the compressors used by the methane capture system). In any event, this file does not provide the data necessary to calculate methane captured as a fraction of methane drained. Other potential metrics that might be used to establish a performance threshold for MC projects, such as the total quantity of methane captured on an annual basis, are fraught with some of the same difficulties associated with methane drainage quantities.

[45] It is of course possible that a mine will capture methane from only some of the drainage boreholes constituting its drainage system, thus leading to methane capture rates significantly less than 100 percent when calculated on the basis of total methane drained from *all* boreholes (as opposed to those boreholes connected to the capture system). However, in defining the MC project boundary, we recommend that drainage boreholes *not* connected to the capture system be excluded. Since these vented boreholes are thus not defined as a part of the MC project, the quantity of methane they vent should not be included in metrics designed to measure the project's performance.

Specifically, the quantity of methane captured at any given mine is more a measure of the mine's geologic conditions than the performance of the methane capture equipment. In short the common practice standard appears to be the best choice by default—other possible performance threshold types are ill-suited to MC projects.

However, it must be emphasized that common practice for MC projects is driven by motivations entirely different from those underlying MDC projects. As discussed above, the federal coal mine health and safety regulations likely play a major role in determining common practice with respect to the latter project types. In general, there are no current *requirements*—federal, state, or local—that should in any way influence a mine operator's choice between venting or capturing the methane drained from gob or pre-mining boreholes (although Pennsylvania's Renewable Portfolio Standards may *incentivize* methane capture and use projects in Pennsylvania—see Chapter 2).[46] This choice is driven by economic considerations, not regulatory requirements. Thus in applying the common practice standard to MC projects, we are in effect addressing economic as opposed to regulatory additionality. Specifically, for those projects operating under conditions in which methane capture is determined to be common practice, the conclusion to be drawn is that such projects are being undertaken to capture and sell (or use) a valuable byproduct of the mining process, and as such are not additional to what otherwise would have happened.

The specific factors affecting an MC project's economic viability are numerous and may, for example, include the mine's distance to the nearest natural gas pipeline, the pipeline's capacity to handle additional gas supplies, the price of natural gas, the types and amounts of impurities in the gas being drained from the mine, etc. We will consider these and other factors later in this section. However, beyond these factors, we hypothesize that one of the most important determinants of an MC project's economic viability is the amount of methane available from the drainage system for capture and use. Quite simply, the larger the quantity of valuable byproduct (methane) available, the greater the revenue (or reductions in energy costs) the project can be expected to yield. All else being equal, we would expect to find that the prevalence of methane capture projects increases in direct proportion to the amount of methane drained.

3.2.2 Preparation of Dataset for the Analysis of MC Projects

To test this hypothesis, we used a subset of the merged emissions/production database we created to analyze the MDC (see prior section on analysis of MDC projects). Specifically, because we are interested here in mines that already utilize methane drainage systems, we eliminated all mines from the merged dataset that did *not* employ methane drainage at any time during the 2000-07 timeframe. Following this elimination, we were left with a new data subset covering the 28 mines (all longwall) that employed methane drainage for at least one year during 2000-07. As described in the preceding section on MDC projects, the sources of this data set include EPA's "Coal 07 draft" Excel file providing information on methane liberation rates, drainage system types, etc.;

[46] It is true that safety concerns have thus far precluded the use of flaring at coal mines, but all projects designed to put the captured methane to use are allowed under the existing regulations.

the Energy Information Administration (for coal production data);[47] EPA's published profiles of gassy underground mines;[48] and CoalUSA magazine[49] (see Section 3.1.4 and the appendix for additional information on the data sources). In addition to data on the total annual amount of methane liberated in 2000-07, this new "MC database" included 2000-07 data on the annual amount of methane drained and vented at each of the 28 mines. In addition, the data set provides a year-by-year indication as to whether or not all or a portion of the drained methane was captured, and the type of use to which the captured methane was applied (e.g., sales to a "pipeline," "electricity" generation, etc.).

To further prepare the MC database for analysis, it was necessary to consider the possibility that some of the mines already utilizing methane capture techniques installed both the methane drainage and methane capture components of their projects at the same point in time. Such projects do not meet the standard definition of an MC project (i.e., projects designed to capture and utilize methane for the first time from mines *that are already venting gas from existing methane drainage systems*), but rather represent MDC projects and as such should not be included in an analysis designed to establish common practice with respect to *MC* projects. However, as we have seen, MDC projects will often effectively *reduce* to MC projects based on the common practice standards established above. Therefore, to address the question of whether some of the mines utilizing methane capture should be excluded from our MC database, it was necessary to apply the MDC common practice standards to the mines in this database in order to distinguish MDC from effective MC projects.

To accomplish this goal, we first identified all of the mines with production-normalized methane liberation rates $\leq$0.25 billion cubic feet per year, as all of the drainage systems falling in this category would qualify as MDC projects under the recommended common practice standards. However, none of these mines capture and use their CMM, and hence they can be retained in the database as representing mines *without* MC projects. Similarly, none of the mines in our database that use pre-mining boreholes have production-normalized methane liberation rates between 0.25 and 1.5 billion cubic feet

[47] EIA, http://www.eia.doe.gov/cneaf/coal/page/database.html.

[48] U.S. EPA, *Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 1999-2003*, EPA 430-K-04-003, 2005; and U.S. EPA., *Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 2002-2006*, EPA 430-K-04-003, 2008.

[49] Weir International, Inc. 2008. "US Longwall Mines – Production and Productivity: September 2007 Year to Date (Mines Producing in Excess of 750,000 tons through September)." *CoalUSA*, March 2008; Weir International, Inc. 2006. "United States Longwall Mining Statistics: 1996-July 2006." Table 2: 2006 June Year to Date US Longwall Mine Production and Productivity; "Table: US Longwall Production 2005," *International Longwall News*, 27 March, 2006. At: http://www.longwalls.com/sectionstory.asp?SourceID=s50; NIOSH, 2005. "Table: US Longwall production 2004." *International Longwall News*, 23 March 2005; NIOSH, 2004. "Table: US Longwall output 2003 now working." *International Longwall News*, 7 April 2004; NIOSH, 2003. "Table: US Longwall output 2002." *International Longwall News*, 21 July 2003. Weir International, Inc. 2008. "Top 50 US Underground Mines (non-longwall) – Production and Productivity: September 2007 Year to Date." *CoalUSA*, March 2008. *CoalUSA*, March 2008.

per year. However, we did identify one mine that is using vertical pre-mining boreholes (in combination with gob and horizontal pre-mining drainage techniques), is capturing and using the methane, and has a production-normalized methane liberation between 1.5 and 4.5 billion cubic feet per year. The vertical pre-mining boreholes in use at this mine are "uncommon" under the common practice standards established in the previous section, and therefore these boreholes should *possibly* be treated as constituting an MDC project (although the *horizontal pre-mining* and *gob* boreholes are common and therefore qualify as an MC as opposed to MDC project). To ascertain whether the vertical pre-mining boreholes should be treated as MDC or MC, we tried to determine whether these boreholes were installed before the methane capture project, or along with the methane capture project. However, based on a review of the historical data contained in EPA's "Coal 07 draft" file, it appears that this particular mine has been both draining and capturing/utilizing its CMM since as far back as 1993. Prior to 1993 the mine does not appear in the data file, suggesting it opened in 1993.[50] Thus we conclude that drainage, capture and utilization of the methane all began at the same point in time. Therefore, this project does *not* qualify as an MC project under the standard definition of this project type; it is rather an MDC project. Furthermore, since the mine's vertical pre-mining boreholes qualify as an MDC project under the common practice standards established above, while the horizontal pre-mining and gob boreholes reduce to an MC project under these same standards, we treated the mine as having only the latter borehole types for our present purpose of analyzing MC projects.

All of the other mines with methane capture systems included in the database can be safely counted as MC projects, given that the production-normalized methane liberation rates at these mines exceed the common practice thresholds established in the preceding section, and hence they would effectively reduce to MC projects even if the methane capture and methane drainage systems were installed at the same point in time.

Finally, a close review of the MC database revealed anomalous methane capture indications for five of the 28 mines. Specifically, the data indicated that methane was captured at these five mines in 2002, but not in any of the subsequent years. SAIC reviewed the data from the "Coal 07 draft" file for these five mines, and found that for 1998 through 2001 the data indicated the mines were not capturing and utilizing methane. Thus the year 2002 was identified as the only year, in a ten-year period, during which methane was being captured at these five mines. In contrast, most of the other mines that practice methane capture are identified as using their capture systems in multiple years. We suspect that the 2002 methane capture indicators for the five mines are in error. In any event, we decided to treat these five mines as *not* utilizing methane capture techniques during the 2000-07 timeframe, since, even if the 2002 data is correct, it appears that the mines' use of methane capture in this one year was atypical and not representative of normal practice at the five mines. In all other cases a mine identified as having employed methane capture at any time during the 2000-07 timeframe was treated as a mine with an MC project for our purposes.

[50] The EPA report *Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 2002-2006* states that the mine first began producing coal in 1994 (p. 3-2).

3.2.3 Data Analyses

Figure 19 is a histogram showing the number of mines with and without methane capture systems, as a function of the arithmetic average quantity of methane drained per year. This arithmetic average was computed using the same procedure applied to the annual methane liberation data in our analysis of MDC projects. The only procedural difference is that for present purposes we used the quantity of methane drained from the mines, as opposed to the total quantity of methane liberated (i.e., methane drained plus methane emitted from the ventilation system). Methane drainage rather than liberation quantities were used in our analysis of MC projects because the decision to either vent or capture the methane will depend only on the amount of methane available for capture; the additional methane emitted through the ventilation system is irrelevant to the vent-or-capture decision.[51]

As Figure 19 indicates, 17 of the 28 mines (60.7 percent) employing drainage systems capture and use the drained methane. The figure supports our hypothesis, that the decision to vent or capture the methane is heavily influenced by the amount of methane available for capture. All thirteen of the mines with average methane drainage in excess of 0.75 billion cubic feet per year have methane capture projects. In contrast, none of the seven mines with average methane drainage amounts less than 0.25 billion cubic feet per year capture the methane for use. In between these two methane drainage ranges is a "grey area," where half of the mines use and half vent their methane. Common practice with respect to methane capture thus appears heavily dependent on the amount of methane available from the drainage system.

To further test this hypothesis, we developed production-normalized estimates of the amount of methane drained, using essentially the same methodology employed to develop production-normalized estimates of methane liberation (see analysis of MDC projects above).[52] The histogram shown in Figure 20 is based on the production-normalized data. One of the 28 mines with drainage systems are excluded from Figure 20 because it lacked the production data needed to develop the production-normalized estimates.

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[51] The amount methane emitted by the ventilation shafts *is*, however, highly relevant to the decision of whether or not to utilize methane drainage, in so far as a primary purpose of drainage is to reduce the amount of methane handled by the ventilation system. For this reason our analysis of MDC projects used the total quantity of methane liberated (through both the return air shafts and the drainage boreholes) as the key metric for assessing common practice.

[52] The only difference between the production-normalized methane liberation estimates and the production-normalized methane drainage estimates is that the latter included only those years between 2000 and 2007 during which the mine's drainage system was in operation. In contrast, the production-normalized methane liberation estimates were computed using methane liberation and production data for all years, including years in which production was zero. This approach was taken because a mine will continue to liberate methane even when it is not producing coal.

Figure 19 - Histogram Showing Prevalence of Methane Capture and Use Projects at Mines Practicing Methane Drainage

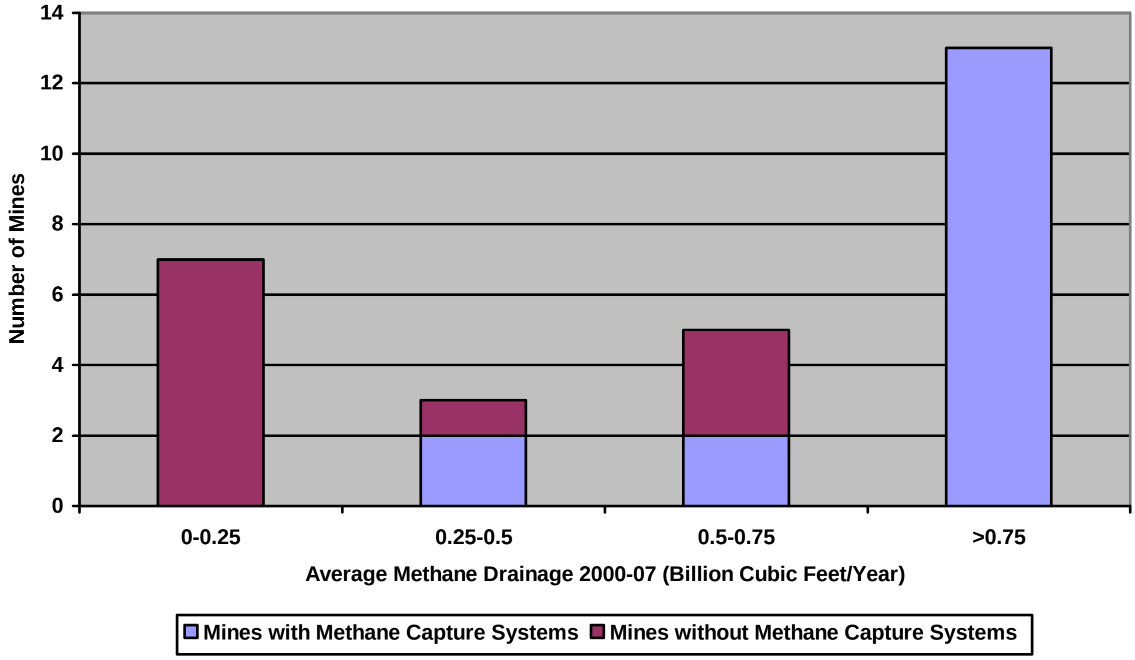


Figure 20 - Histogram of Capture System Usage by Mines Based on Production-Normalized Annual Methane Drainage in the 2000-07 Period

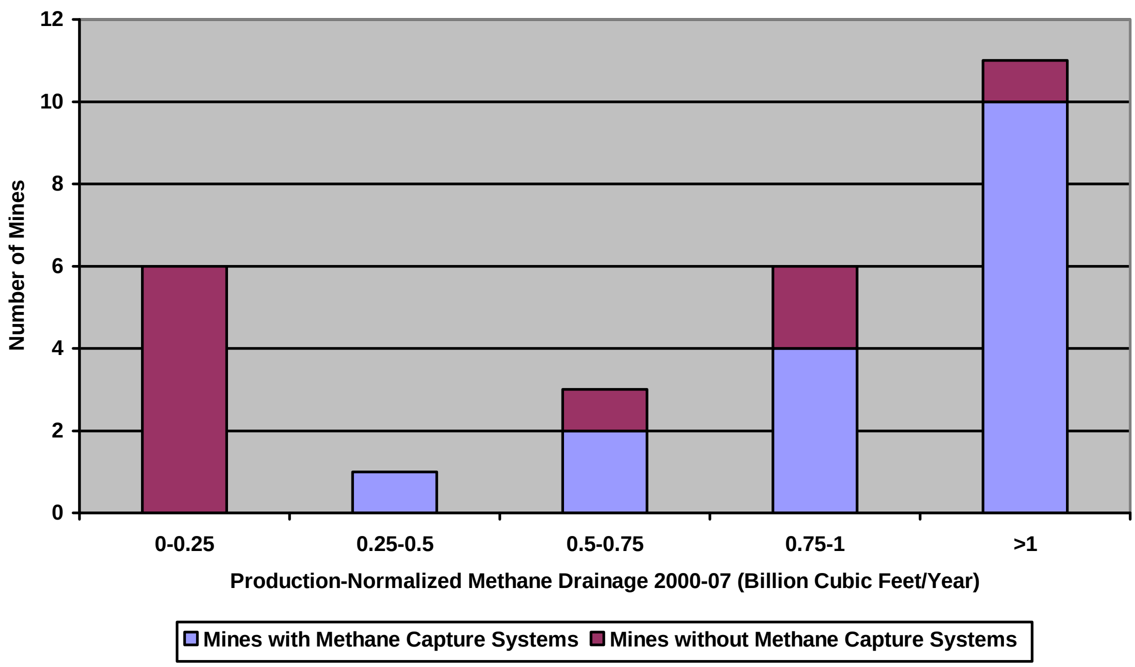


Figure 20, like Figure 19 supports the basic hypothesis that the decision to vent or capture methane from drainage systems depends heavily on the amount of methane drained. As in Figure 19, mines venting rather than capturing drained methane are in the majority only at low production-normalized methane drainage rates less than 0.25 billion cubic feet per year. Methane capture is the common practice at mines with methane drainage falling in the 0.25 to 1 billion cubic foot per year range. Seven of the ten mines in this category are capturing and using methane. At methane drainage levels exceeding 1 billion cubic feet per year ten of the eleven mines use methane capture.

Regional Analysis

An attempt was made to assess whether common practice with respect to the use of methane capture varies across regions. Whereas common practice with respect to methane *drainage* is unlikely to exhibit much regional variation, given that the decision to utilize drainage techniques is often driven by *federal* regulations, the same cannot be presumed for methane *capture*. On the contrary, given that the decision to initiate a capture and utilization project will generally be driven by economic criteria rather than regulations, regional variations in common practice, reflecting regional variations in the underlying economic criteria, are a real possibility that must be investigated.

Table 7 presents the results of our regional analysis. In the table, mines are classified as to whether they have production-normalized methane drainage rates greater or less than 0.25 billion cubic feet per year. The value of 0.25 billion cubic feet per year was selected as the threshold on the basis of Figure 20, which indicates that once this threshold is crossed the majority of mines with drainage systems capture and use the methane (e.g., 75 percent of the mines with methane drainage rates between 0.25 and 0.75 billion cubic feet per year capture and use the methane).

Table 7 - Regional Analysis of Methane Capture Usage Among Mines with Drainage Systems

State/Region	Mines with Normalized Methane Drainage >0.25 Billion ft^3			Mines with Normalized Methane Liberation $\leq$0.25 Billion ft^3		
	Number with Drainage Systems	Number with Capture Systems	Percent with Capture Systems	Number with Drainage Systems	Number with Capture Systems	Percent with Capture Systems
Pennsylvania	3	3	100	1	0	0
W. Virginia	6	4	67	1	0	0
Virginia	2	2	100	0	0	NA
Kentucky	0	0	NA	1	0	0
Alabama	5	5	100	0	0	NA
Eastern U.S.	**16**	**14**	**87**	**3**	**0**	**0**
Colorado	3	1	33	2	0	0
Utah	1	1	100	1	0	0
New Mexico	1	1	100	0	0	NA
Western U.S.	**5**	**3**	**60**	**3**	**0**	**0**
Total U.S.	**21**	**17**	**81**	**6**	**0**	**0**

Table 7 indicates little regional variation in common practice amongst mines with production-normalized methane drainage in excess of 0.25 billion cubic feet per year. Regardless of their regional location, the majority of the mines in this category capture and utilize methane (87 percent of the eastern mines and 60 percent of the western mines). None of the six mines draining less than 0.25 billion cubic feet per year capture and utilize their CMM, regardless of mine location. Thus we recommend against establishing regional variations in the common practice standards for MC projects.

Analysis of Drainage System and Utilization Project Type Data

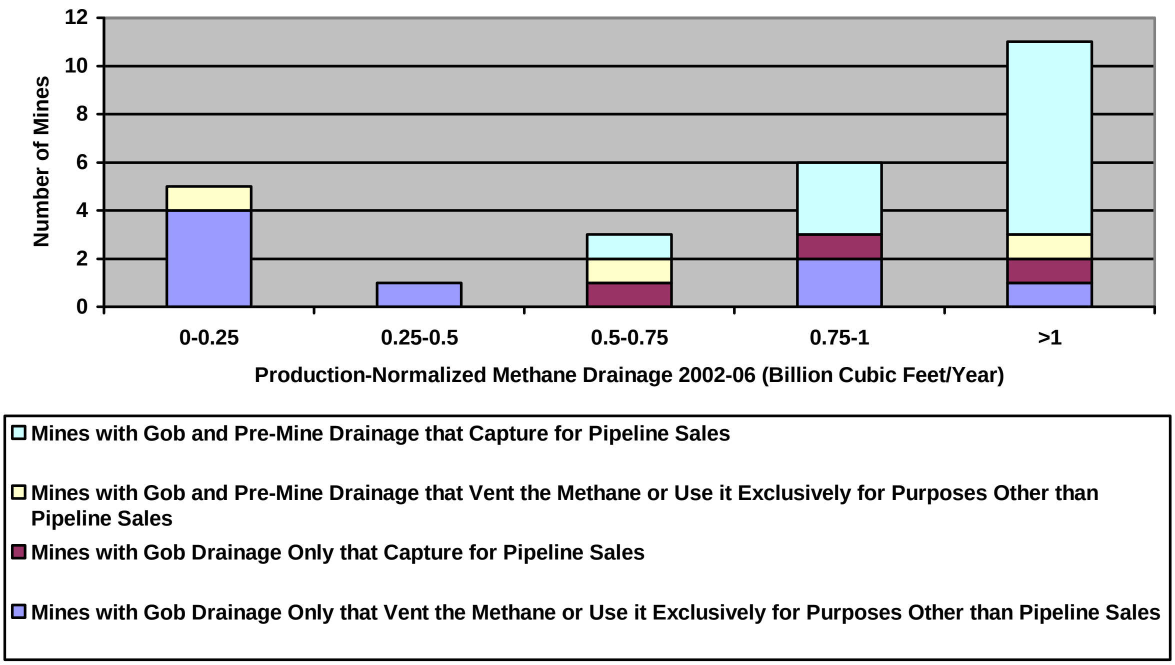
Another possible determinant of the choice to capture or vent methane (besides the quantity of methane drained) is the type of drainage system employed. In particular, the ability of a mine operator to sell coal mine methane to natural gas pipeline companies depends on the purity of the methane captured. Although the EPA database does not provide information on the methane content of the gas drained from gassy mines, it does indicate the type(s) of drainage systems employed by these mines. While the methane drained through pre-mining horizontal and vertical boreholes will generally meet a pipeline company's product quality requirements, methane drained via gob boreholes is often significantly contaminated by mine air and may not meet the pipeline requirements. Mines employing both pre-mining and gob drainage may be able to mix the gob methane with the pre-mining methane to achieve a saleable product; however, mines relying exclusively on gob drainage will not have this option. Enhancement of the gas to meet pipeline requirements is technically feasible and indeed is being undertaken at a number of mines, but the gas processing involved adds to the costs of the project. While other possible uses of the captured methane (e.g., onsite electricity generation) do not require that the gas meets the high purity levels imposed by gas pipeline companies, it is important to note that the vast majority of mines currently capturing methane (13 out of 17) sell all of the captured methane to pipelines. Two of the other mines sell a portion of their captured methane to pipelines, while using the remainder for other purposes (electricity generation in one case, and thermal coal drying in the other). Only two of the seventeen mines practicing methane capture use all of the methane for purposes other than sale to pipeline companies (electricity generation in one case, and heating of the mine ventilation air in the other).[53] Thus in order to make use of the most popular methane utilization technique, the mine operator must meet stringent gas quality requirements, and for this reason the type of drainage system employed may influence the decision of whether to capture or continue to vent the methane.

To test this hypothesis, we developed the histogram shown in Figure 21, which shows methane capture usage as a function of both the production-normalized rate of methane drainage and the type of drainage system used. The histogram does not distinguish between vertical and horizontal pre-mining drainage, because both of these types of systems produce a high-quality gas uncontaminated by mine air, and hence the distinction is not relevant to our present purpose of inferring whether gas quality has an influence on the vent-or-capture decision. In addition to excluding the mine without production data,

[53] Use of the captured methane at one mine is unspecified in the Coal 07 draft file.

this histogram also excludes one mine with an unspecified drainage system type in the EPA dataset.

Figure 21 - Histogram Showing Methane Capture Usage as a Function of Drainage System Type and Normalized Annual Methane Liberation in the 2000-07 Period



A number of salient points can be drawn from Figure 21. First, 12 of the 15 mines that use both gob and pre-mining (horizontal and/or vertical) boreholes are capturing and selling the methane from these boreholes to pipelines. In contrast, eight of the eleven mines that rely exclusively on gob boreholes either vent the methane or use it for a purpose that does not require a high quality gas. These results, considered in isolation from the production-normalized methane data, seems to support the hypothesis that the methane drainage technique influences the decision of whether or not to capture the methane and sell it to a pipeline. However, when we consider only those mines draining in excess of the 0.25 billion cubic foot per year threshold, we find that methane capture and use is a common practice for all mines regardless of whether or not they employ pre-mining drainage techniques. Three of the seven "gob-drainage only" mines with methane drainage rates ≥0.25 billion cubic feet capture and sell the methane (42.9 percent), while 12 of the 14 (85.7 percent) "gob plus pre-mining" mines recover their CMM for sale to pipelines. Thus, while methane capture at mines above the 0.25 threshold is *more prevalent* at those mines using pre-mining drainage techniques than at the mines relying exclusively on gob drainage, it nonetheless appears to be a common practice at both sets of mines.

Furthermore, the data do not enable a robust comparison of "gob only" with "gob and pre-mining" operations at those mines draining less than 0.25 billion cubic feet per year of methane, because there is only one "gob and pre-mining" operation falling below the

0.25 threshold. For this reason, while we can conclude that the use of methane capture at “gob-only” mines in this category is uncommon (and in fact non-existent), we cannot determine whether it would or would not be uncommon for “gob and pre-mining” operations. However, what we *can* conclude, based on Figure 21, is that “gob and pre-mining” drainage systems with drainage rates less than 0.25 billion cubic feet per year are a rarity, and therefore any future application of methane capture and use to such low-volume drainage systems will most likely also prove to be rare. In short, methane capture is not a common practice (in fact it is non-existent) at mines with methane drainage rates below 0.25 billion cubic feet per year.

In sum, the data shown in Figures 19, 20 and 21 suggest that MC projects should be defined as “common practice” at all mines draining in excess of 0.25 billion cubic feet of methane per year, and as uncommon at all mines operating below this threshold.

Although we do not recommend developing separate common practice standards by drainage system type, a strong argument can be made for separate standards by *utilization* project type. As previously noted, only four of the seventeen mines with known utilization project types use the captured methane for purposes other than for sales to pipelines. Of these four mines, one is generating electricity with a portion of the captured methane (and selling the remainder to a pipeline), one is using *all* of the captured methane to generate electricity, one is using a portion of the methane to fuel a thermal coal dryer at the mine’s prep plant (while selling the remainder to a pipeline), and one is using all of the methane to heat the mine ventilation air. Thus we can conclude the following:

- Use of methane for pipeline sales is common practice, in so far as it is used at 88 percent (15 of 17) of the mines that capture methane, and 53 percent (15 of 28) of the mines that drain methane;

- Use of captured methane for electricity generation is uncommon, in so far as it is limited to 12 percent of the mines that capture methane, and seven percent of the mines that drain methane;

- Use of captured methane for heating ventilation air or fueling thermal coal dryers is uncommon (limited to only six percent of the mines that capture methane, and four percent of the mines that drain methane);

- Application of captured methane to any use other than the above three is not only uncommon but non-existent.

There are two possible explanations for the general lack of end-use projects other than those involving sales to pipelines. First, these projects may be generally uneconomic under current conditions. Alternatively, such projects may be economically viable, but *less so* than pipeline sales projects. Under this second interpretation, on-site projects to generate electricity, heat, etc., would be more numerous than actually observed were it not for the fact that they must compete with a generally more preferable end use—i.e., selling the CMM to a pipeline. In other words, we might hypothesize that pipeline projects are in effect distorting our analysis of common practice with respect to other end use project types, by dominating the competition between the various end use options. If true, this hypothesis would suggest that other end use project types are not generally additional, despite their rarity.

To test this hypothesis, we can eliminate all of the mines with pipeline sales projects from our database, and consider whether or not other end use projects are common practice within the remaining group of mines—a group for which competition from pipeline projects is clearly not a barrier to the application of other end uses. However, before performing this analysis, we should first consider that two of the four non-pipeline projects currently in operation (an electricity generation project and a thermal coal drying project) are located at mines that *also* sell a portion of their CMM to pipelines. Clearly these two projects are not being adversely affected by competition from pipeline projects, as they co-exist with the latter. In fact, the existence of these co-located projects suggests that there may be other opportunities for the application of on-site end uses at mines that currently sell their CMM—the fact that such co-located on-site projects are uncommon indicates that these on-site applications may be subeconomic, rather than merely less economic than pipeline sales projects. In any event, the two co-located on-site projects should be excluded from our analysis, because competition from pipeline sales projects clearly did not prevent these two projects from being undertaken.

Focusing then on the two remaining on-site end use projects—projects which *may* not have been undertaken had pipeline sales projects been feasible at these two mines—and on the mines that are currently venting their CMM, we can draw the following conclusions with respect to common practice:

- Only one of the 12 mines (eight percent) that utilize drainage systems *not* connected to natural gas pipelines, and one of six (16.7 percent) of these mines which drain more than 0.25 bcf annually, currently captures methane to generate electricity;

- Only one of the 12 mines (eight percent) that utilize drainage systems *not* connected to natural gas pipelines, and one of six (16.7 percent) of these mines which drain more than 0.25 bcf annually, currently captures methane to heat the mine ventilation air.

Based on the above analysis we must conclude that on-site end use projects are uncommon even at mines that do not sell their CMM to pipelines. In fact, CMM end use project types other than electricity generation, ventilation air heating, and thermal coal drying are non-existent. Even among mines with high (>0.25 billion cubic feet per year) drainage rates, electricity generation is an uncommon end use, as is ventilation air heating. This finding suggests that such project types are generally uneconomic under current conditions, rather than simply less economic than pipeline sales projects. Thus, even if the current pipeline sales projects did not exist, it is not clear that other project types would take their place. We therefore believe it is appropriate to consider the entire population of mines with drainage systems, and not just those mines that do not sell CMM to pipelines, when assessing common practice with respect to non-pipeline end use projects. On this basis, only two of the twenty one mines with high (>0.25 billion cubic feet per year) drainage rates use their CMM to generate electricity, while one mine each uses the CMM for thermal coal drying and ventilation air heating.

Pipeline Projects Versus Natural Gas Prices

One might expect that the value of recovered and utilized methane could also influence the vent-or-utilize decision made by owners of degasification systems, although it should not influence the decision to install the degasification system itself. The possibility of a relationship between natural gas prices and the decision to capture CMM for sale to pipelines was investigated using time series data on the US national average wellhead natural gas price for the 1990-07 timeframe. These data, obtained from the Energy Information Administration's (EIA) natural gas price archives, are plotted against the number of pipeline sales projects in operation in each year in Figure 22. Also shown is the total annual quantity of methane drained at mines with such projects, and methane drained as a percentage of methane liberated (i.e., methane drained plus methane emitted through return air shafts). As the figure indicates, natural gas prices remained relatively flat during the 1990s, but followed a sharp upward trend over the last decade. In contrast, the number of pipeline projects showed little change over this same period. Methane drainage quantities/fractions at mines with pipeline projects fluctuated significantly over the same period, but exhibited little or no discernible long-term trend. Regression analyses were performed with price as the independent variable and the number of projects, the quantity of methane drained, and the percentage of methane drained as the dependent variables; in all cases the analyses showed no significant relationship[54] between price and the dependent variables (see Table 8). The lack of a relationship between price and the quantity or percentage of methane drained should not necessarily be surprising, as methane drainage quantities may be more a function of fluctuations in geological conditions than in project parameters under the mine operator's control (although operators can increase drainage quantities, e.g., by adding horizontal and vertical pre-mining boreholes to gob drainage systems, and by drilling boreholes on a closer spacing pattern). However, the lack of an observed relationship between gas prices and the number of projects capturing methane for pipeline sales is less expected. The absence of a significant correlation, indicated by the T-statistic of 0.603, suggests that the economically viable opportunities for capturing and selling CMM may have been fully exploited and exhausted, at least within the range of natural gas prices encountered over the last two decades. In fact as of 2007, only five of the twenty mines that use drainage systems were not capturing and utilizing their methane. Furthermore, one of these five mines does in fact have a pipeline sales project, although this project was not in operation in 2007. Of the remaining four mines, two have production-normalized methane drainage quantities below 0.25 billion cubic feet per-year, suggesting that the quantity of methane available for capture may be insufficient to generate the level of revenues needed to justify a methane-capture-and-sales project. One of the two

[54] T-statistic indicating the significance of the correlation coefficient, r, from each linear regression of sample size n and n-2 degrees of freedom. $T = r \times \mathrm{sqrt}[(n-2)/(1-r^2)]$

remaining mines is located over seven miles away from the nearest natural gas transmission pipeline; as we shall see, seven miles may represent a threshold beyond which the construction of a feeder line from the mine to the pipeline becomes uneconomic. While both insufficient drainage quantities of less than 0.25 billion cubic feet per year and long distances of greater than seven miles to the nearest pipeline are ultimately economic, not technical, barriers to pipeline sales projects that could potentially be overcome given a high enough natural gas price, under the price range we have seen over the last two decades observed common practice strongly indicates that these barriers are real. In short, the economic limits to further market penetration of pipeline sales projects may have been reached under current economic conditions.

Figure 22 - Time Series Showing Pipeline CMM Utilization Project Characteristics and Average US Natural Gas Value, 1990-2007

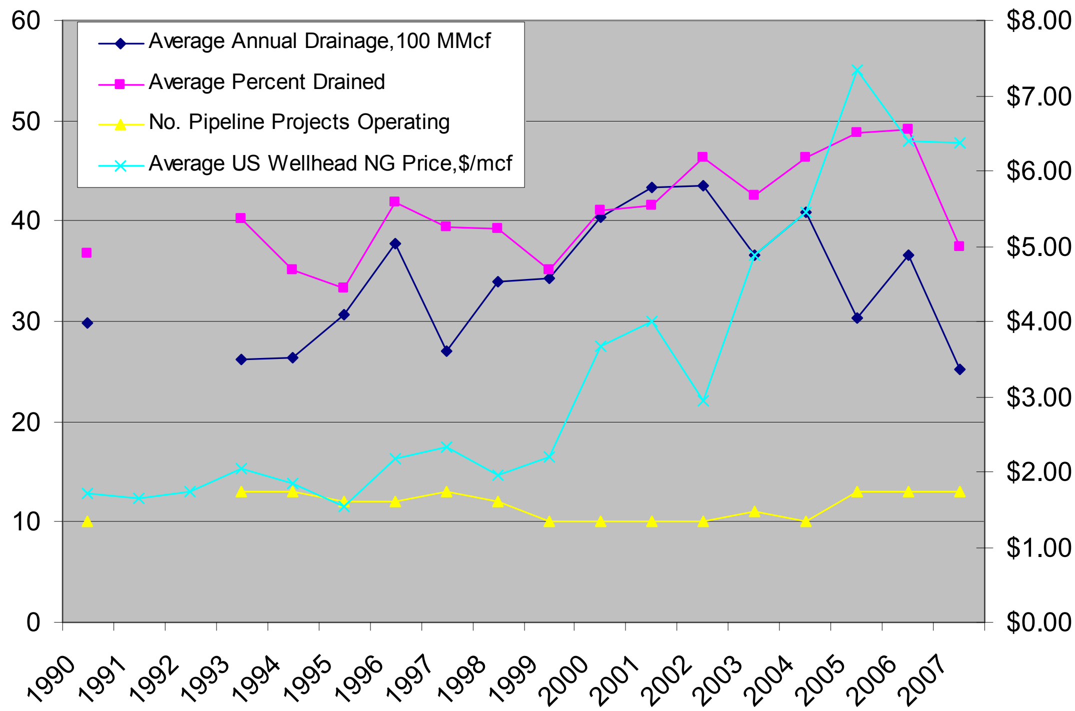
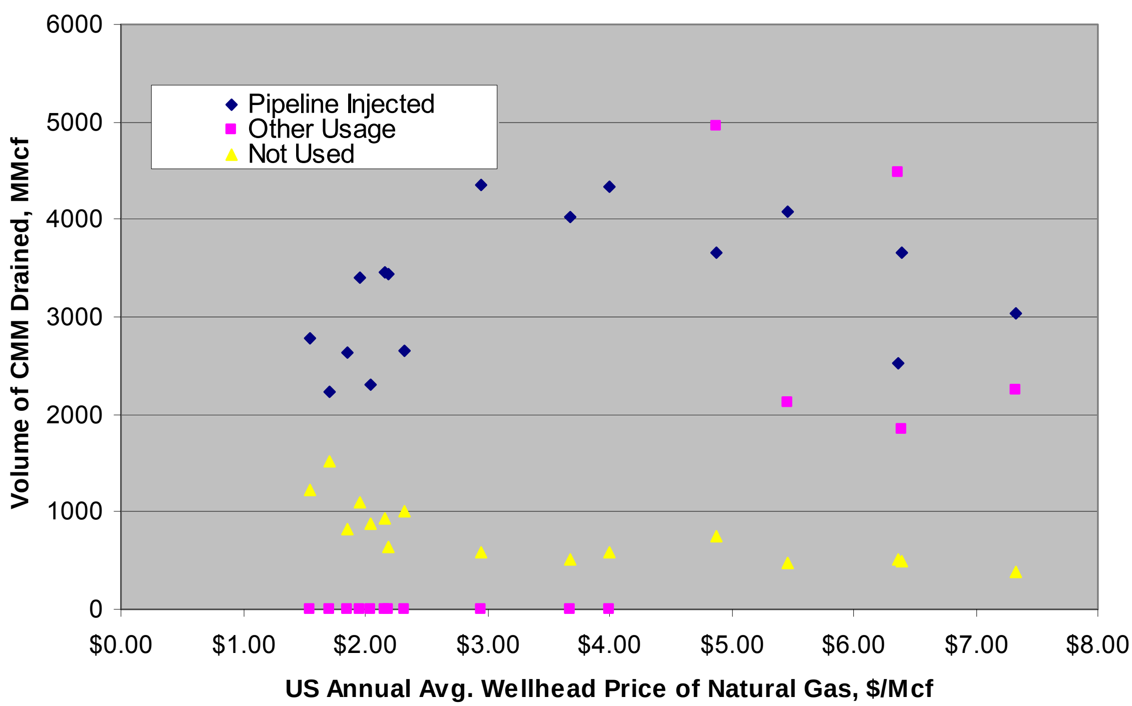


Table 8 - Linear Regression Results Relating Natural Gas Prices with Number of Pipeline Utilization Projects, Drainage Quantities, and Drainage Percentages

Dependent Variable	Coefficient of Determination (R^2)	T-Statistic
No. of Pipeline Projects Operating	0.0253	0.6028
Avg. Annual Drainage Volume	0.0217	0.5573
Avg. Percent Drained	0.1812	0.6894

The relationship between price and recovered CMM end use was further explored by segregating the mines into three groups—those with pipeline sales projects, those with other capture and utilization projects, and those that vent their drained CMM—and examining the relationship between price and the volume drained separately for each group. Figure 23 plots the observations, and Table 9 shows the results of the analysis, which again found no significant statistical relationship between the value of sold natural gas and the volume of CMM drained for mines with pipeline projects. However, a significant negative relationship (T-statistic of 4.4) was found between price and the amount of CMM *vented* through drainage systems, suggesting that higher natural gas prices could potentially be acting as a disincentive to venting methane. That said it is the volume of methane drained per year, rather than the price of natural gas, which appears to be by far the more important factor in determining the vent-or-sell decision. As Figure 23 shows, all annual average methane drainage quantities below 2 billion cubic feet during the 1990-2007 timeframe were either vented or used for some purpose other than pipeline sales, while virtually all quantities above 2 billion cubic feet were captured and sold to pipelines.[55] In any event, the lack of a corresponding significant relationship between natural gas prices and the quantity of methane drained at mines with pipeline sales projects cautions us against developing common practice standards on the basis of gas prices.

Figure 23 - Time Series Showing CMM Capture Project End Use Type and Average US Natural Gas Wellhead Price, 1990-2007



[55] Range of annual average volume drained for pipeline sale was 2,239-4,347 MMcf for the 1990-2007 period. The price of natural gas in the year in which the two endpoints of the range occurred were $1.707 and $2.95, respectively. The same range for drainage that was emitted was 376 – 1,512 MMcf and the prices during those years were $7.33 and $1.707. A relationship of similar statistical significance was found between the amount of CMM drained for use onsite and wellhead price. Interpretation of the meaningfulness of this relationship, however, should be tempered by the lack of lengthy time series for the mines providing examples of methane utilization projects other than pipeline sales (the first onsite CMM utilization project began operation in 2003).

Table 9 - Linear Regression Results for Data Segregated by Type of End-Use Project (Pipeline Sales, Other Uses, and Venting)

Dependent Variable	Coefficient of Determination (R^2)	T-Statistic
Quantity of Methane Drained for Pipeline Injection	0.0736	1.0546
Quantity of Methane Drained for Other (non-Pipeline) Uses	0.5705	4.3123
Quantity of Drained Methane Emitted	0.5805	4.4015

With only two mines utilizing recovered CMM to operate electricity generation projects, the sample is insufficient to draw any conclusions as to whether the price of electricity drives the use of CMM for this purpose. All mines have significant electricity consumption needs. Thus, the dearth of such generation projects indicates that the ability to offset electricity purchases does not significantly affect the decision of whether or how to utilize recovered CMM.

Based on our analyses, SAIC does not recommend including any reference to the value of recovered methane when setting common practice standards for CMM recovery and utilization projects.

Analysis of Pipeline Utilization Project Status and Existing Pipeline Infrastructure

Projects that inject recovered CMM into a pipeline may also be more common among mines located near existing pipeline infrastructure that is of sufficient capacity to handle additional natural gas volume. Existing proximate infrastructure would decrease CMM recovery and utilization project costs by hundreds of thousands to millions of dollars per mile of feeder line that does not have to be constructed as part of the CMM utilization project. The relationship between natural gas pipeline proximity and pipeline utilization of CMM among mines with degasification systems was analyzed using mine-level data. The EPA's report series, *Profiles of Selected Gassy Underground Coal Mines,*[56] contains information detailing the distance to and size of the nearest existing pipeline for each profiled mine.

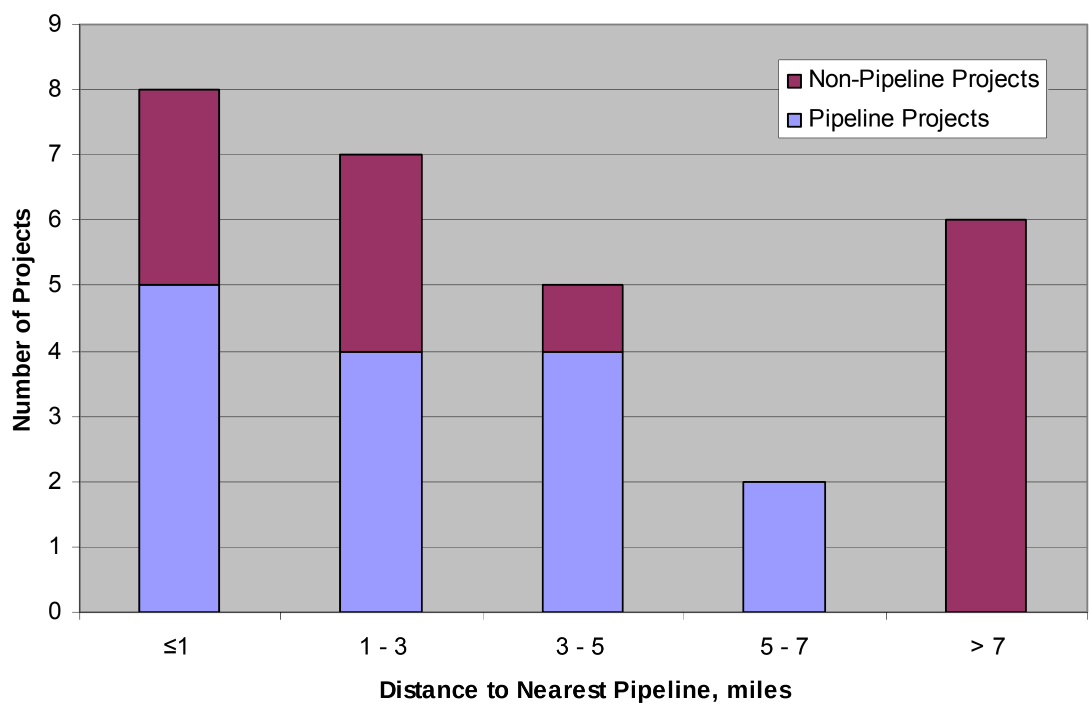
The most recent such data for each mine was imported into the degasification system database constructed by SAIC. Of the 28 mines employing degasification systems, nearest pipeline characteristics were available for 27 of these mines in the *Profiles*. The distance to the pipeline for the remaining mine was obtained via personal communication

[56] U.S. EPA, *Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 2002-2006*, September 2008, and *Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 1999-2003*, September 2005.

with a local CMM industry participant.[57] The nearest pipeline documented, however, does not necessarily have sufficient remaining capacity to receive the CMM from the recovery project. This may be particularly true of pipelines in the east. For all of the mines, publicly available data is insufficient to determine the distance to the closest pipeline with surplus capacity.

An initial analysis examined all 28 mines according to pipeline utilization status and distance to the nearest pipeline. This analysis found that mines with pipeline utilization projects (n=15) were, on average, 2.3 miles from the nearest pipeline, while those not injecting recovered CMM (n = 13) averaged a distance of 8.8 miles from the nearest pipeline. As shown in Figure 24, *all* fifteen pipeline injection projects are located within 5.5 miles of an existing natural gas pipeline. However, an additional seven mines that do *not* inject into pipelines also lie within this distance of a pipeline. In contrast, *none* of the six mines located more than seven miles from the nearest pipeline are selling their methane. Three of these six mines drain less than 0.25 bcf of methane per year. For these mines, the relatively low CMM drainage rate may play a greater role in the decision to vent CMM than does distance to the nearest pipeline, although it is not possible to determine which of these two factors—methane quantity available or distance to the nearest pipeline—was given more weight in the mine operator's decision. Nonetheless, it appears that a distance of six to seven miles represents a threshold distinguishing common practice.

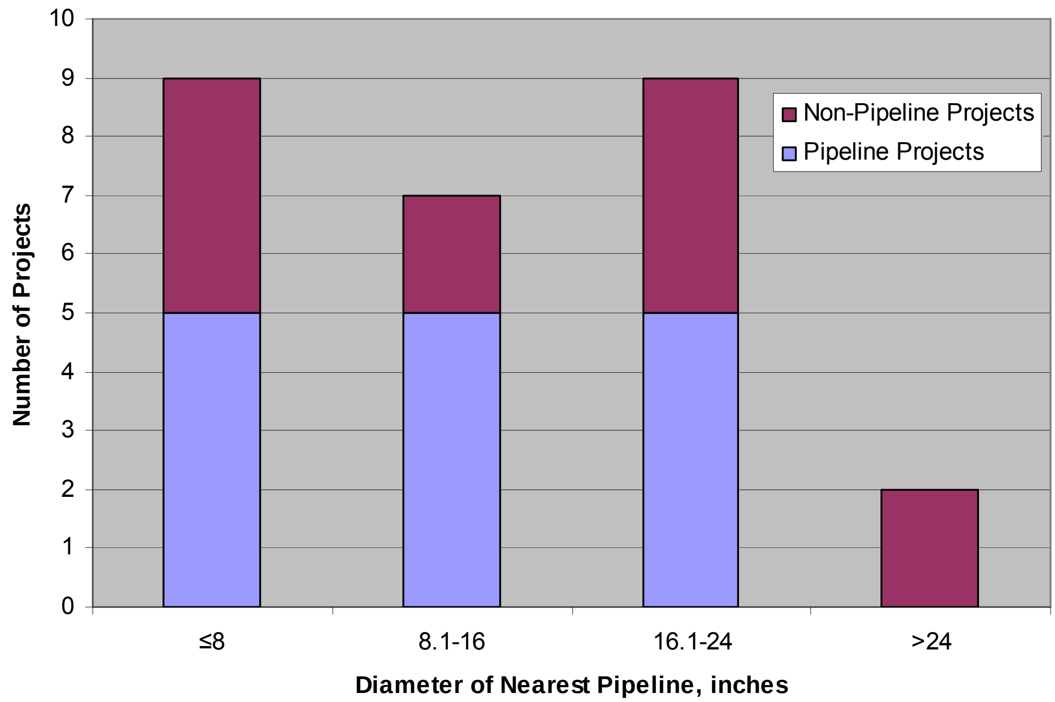
Figure 24 - Distance to Existing Pipeline Infrastructure among CMM Recovery Projects



[57] E-mail from Charlee Bolger, Environmental Scientist, Raven Ridge Resources Inc., May 20, 2009.

The diameter of the nearest pipeline was also analyzed[58], under the hypothesis that pipeline sales projects are more likely when large diameter (i.e., large capacity) pipelines are located near the mines. However, as shown in Figure 25, the diameter of the nearest pipeline does not appear to explain the decision to capture and sell CMM. On the contrary, pipeline sales projects are as prevalent among smaller diameter (≤8-inch) pipelines as for larger diameter (>8-inch) pipelines. Here it should be noted that although pipeline diameter should serve as a proxy of the pipeline's capacity, this measure does not provide information on the amount of *unutilized* capacity available on the line. Unfortunately data on unutilized capacity is not available.

Figure 25 - Diameter of Existing Pipeline Infrastructure among CMM Recovery Projects



Analysis of Utilization Project Type and Status Data and Mine Area Topography

The EPA's *Profiles of Selected Gassy Underground Coal Mines* also includes a brief qualitative description of the topography surrounding the mine. These descriptions were converted into an ordinal ranking from 1-5, with 5 signifying the most mountainous terrain and 1 the most level. The decision to utilize or to emit recovered CMM was evaluated with respect to these ordinal values for the 24 mines with degasification systems for which a terrain description is available in the *Profiles*. The results of this analysis are displayed in Table 10. While one might expect that pipeline projects would be less prevalent among mines located in more mountainous terrain (because the costs of building a feeder line to the nearest transmission pipeline may increase as the ruggedness of the terrain increases and it may become prohibitively difficult to tap, maintain and

[58] Diameter data was only available for those 27 mines in the EPA's *Profiles*.

monitor boreholes spread across such rough terrain), the data do not support this hypothesis. On the contrary, seven of the fourteen pipeline CMM projects that have terrain profiles are found in topographic categories 4 and 5—the most rugged of the five terrain categories. Thus, the topographic profile of the land surrounding the mine does not appear to be a significant determinant of how or whether to utilize recovered CMM.

Other locational factors may have a significant bearing on the decision of whether or not to implement a CMM drainage system and whether or how to utilize the recovered CMM if drainage is employed. Such factors include the existence of adjacent gassy mines that owned by the same mining company and the location of the mine relative to producing coalbed methane fields. Complexes of gassy mines provide their owners with an opportunity to achieve economies of scale in the implementation of both drainage and utilization projects, making these projects more financially viable undertakings. For example, two mines with drainage systems may be able to share borehole drilling equipment as well as the feeder line connecting the mines to the nearest natural gas transmission pipeline. Similar sharing of equipment and surface infrastructure may be possible when a mine is located near a producing CBM field—or, for that matter, a conventional gas field.

Table 10 - Terrain Profile of Area Surrounding Existing CMM Recovery Projects

Terrain Category	Pipeline Use	Other Use	Not Used
5	3	1	1
4	4	0	0
3	1	0	3
2	6	1	1
1	0	0	1
Not Specified	1	0	3

A number of the existing CMM recovery and utilization projects occur at pairs or groups of adjacent mines that comprise jointly owned and operated mine complexes, Such mining and drainage complexes benefit from the geographic, and resulting monetary, advantages to project development that come from the ability to share infrastructure. Similarly, at least two of the mines that employ degasification and utilize the recovered CMM for pipeline injection are located within producing CBM fields with which they share infrastructure. However, incomplete anecdotal mentions of these factors within EPA's mine *Profiles* prohibits a full analysis of the complete gassy mine or degasification system database constructed by SAIC in order to examine the extent of co-location with respect to the occurrence of either drainage or utilization projects. Should such data become available, the Reserve may wish to re-examine CMM recovery and utilization common practice with respect to mines located within active CMM and/or CBM drainage fields.

Additional Factors and Analysis of CMM Recovery and Utilization Project Implementation

While the decision to use employ methane drainage is primarily driven by safety regulations, the decision to utilize the recovered CMM is a judgment made by the mine owner based upon the variety of mine factors discussed above, as well as factors related to the company itself. The extent of a particular company's past experience with CMM utilization projects and whether the mine's parent company also includes expertise in natural gas, electricity generation or other potential utilization scenarios will likely play an important role in the decision making process. A single large coal company, for example, owns ten of the 28 mines that have employed degasification systems and five of the 17 mines with utilization projects. Further, another coal company with active degasification and pipeline utilization projects, is a co-owner of a company that operates coalbed methane recovery wells. However, we do not recommend development of a common practice standard based on the mine operator's past experience with CMM utilization projects as such a standard might potentially discourage the companies most active in the development of such projects from pursuing further additional projects.

3.2.4 Definition of Tentative Common Practice Standards for MC Projects

Based on the above analysis of current utilization project types, we *tentatively* recommend that *all* MC projects designed to utilize the methane for any purpose other than pipeline sales be qualified as additional under the common practice standard. Depending on the specific utilization project type, such non-pipeline projects are rare to non-existent at present. MC projects that include both pipeline sales and other uses (e.g., electricity generation) should be treated as two separate projects for the purposes of applying the common practice standard, and the project involving uses other than pipeline sales should be qualified under the common practice standard.

Based on our analysis of Figures 19 and 20, MC projects that involve sales of the captured gas to pipelines should be qualified as offsets projects *only* if the mine's estimated methane drainage rate is 0.25 billion cubic feet per year or less. Above this 0.25 threshold, capturing drained methane and selling it to natural gas pipeline companies is common practice. Potential alternative approaches mine operators might follow to estimate their drainage rate, for purposes of comparison with the threshold, are presented in Chapter 4.

One possible exception to the above methane quantity standard could be considered by the Reserve. Based on our pipeline infrastructure analysis, one finds that pipeline utilization is, indeed, more prevalent among mines proximate to existing infrastructure. Specifically, whereas the majority of mines located less than seven miles from the nearest pipeline are capturing and selling their methane, none of the mines located more than seven miles from existing infrastructure do so. Based on this result, some consideration might be given to accepting pipeline sales projects with methane drainage rates that exceed 0.25 billion cubic feet per year, *if* the project requires the construction of a feeder line greater than a certain length x. Rather than setting x equal to seven miles, we would recommend the use of a more conservative, round number, such as 10 miles.[59] Caution in considering the application of a distance-related allowance should, however, be taken. While we are quite certain that, at *some* threshold distance, projects involving the capture and sale of methane to a pipeline will become subeconomic and therefore additional without the added revenues from offsets credits, it is not clear that the data available to us to define this threshold is sufficiently robust. Specifically, the available data indicates only distance to the *nearest* pipeline; it does not tell us, in the case of mines with pipeline sales projects, whether this pipeline is in fact *the* pipeline that is receiving the CMM. Furthermore, in the case of mines that are *not* selling their CMM, we do not know whether or not the nearest pipeline in fact has sufficient excess capacity available to be able to accept further deliveries. Thus while a common practice standard based on a10-mile threshold distance appears reasonable based on the available data, the limitations inherent in this data may be too great to support such a standard.

As was the case for the MDC projects considered previously, the above common practice standards for MC projects will be subjected to further evaluation, adjustment, and finalization in Chapter 4. For now they should be considered our *tentative* recommendations.

3.3 VAM Projects

There are at present no commercial projects using Ventilation Air Methane Technology at active coal mines in the United States. There is one demonstration project that received approval from the Mine Health and Safety Administration (MSHA) in April 2008; Section 1.3.5 provides a brief description of this project and its performance to date. Since commercial VAM projects are non-existent at present, we recommend that all commercial VAM projects be qualified as additional under a common practice standard.

[59] A regional caveat to this allowance does not appear justified, as *no* mines east or west, that are located more than 5.5 miles from a pipeline and drain more than 0.25 bcf CMM per year currently utilize this CMM for pipeline sales.

4 EVALUATION, FINALIZATION AND APPLICATION OF THE PROPOSED COMMON PRACTICE STANDARDS

4.1 Summary of the Proposed Common Practice Standards

The recommended common practice standard for VAM projects is quite simple: all such projects that do not receive government subsidies are qualified as additional. However, the recommended common practice standards for MDC and MC projects are more complex. These common practice standards are presented in visual form in Figures 26 and 27. The two figures are flowcharts illustrating the decision process a mine operator would follow to determine whether or not a specific project qualifies as additional. An operator implementing a project designed to add both methane drainage and methane capture systems to existing or new mines that have neither (i.e., an MDC project) would begin the decision process with Figure 26; an operator adding a methane capture and utilization project to a mine that is already venting methane from an existing drainage system (i.e., and MC project) would begin the common practice determination using Figure 27. As Figure 26 shows, the process of evaluating an MDC project begins by answering the question "Is the mine a longwall mine?" MDC projects *not* located at longwall mines (i.e., projects at room and pillar mines) immediately qualify as additional. MDC projects at longwall mines must proceed to a second question, "What is the average methane liberation rate at the mine?" There are four possible answers to this question, as follows:

- If the annual methane liberation rate is less than 0.25 billion cubic feet per year, the MDC project qualifies as additional in its entirety.

- If the annual methane liberation rate is higher than 0.25 billion cubic feet per year but under1.5 billion cubic feet per year, the CMM captured and used from any pre-mining boreholes (horizontal and vertical) qualifies for offsets credits. To determine whether or not the CMM from gob boreholes qualifies, the project developer would proceed to Figure 27 (where the CMM from the gob boreholes is treated as an MC project).

- If the annual methane liberation rate is greater than 1.5 billion cubic feet per year but less than 4.5 billion cubic feet per year, the CMM captured and used from any pre-mining *vertical* boreholes qualifies for credits. To determine whether or not the CMM from gob and horizontal pre-mining boreholes qualifies, the project developer would proceed to Figure 27 (where the CMM from the gob and horizontal boreholes is treated as an MC project).

Figure 26 - Decision Tree for Applying Tentatively-Proposed Common Practice Standards to an MDC Project

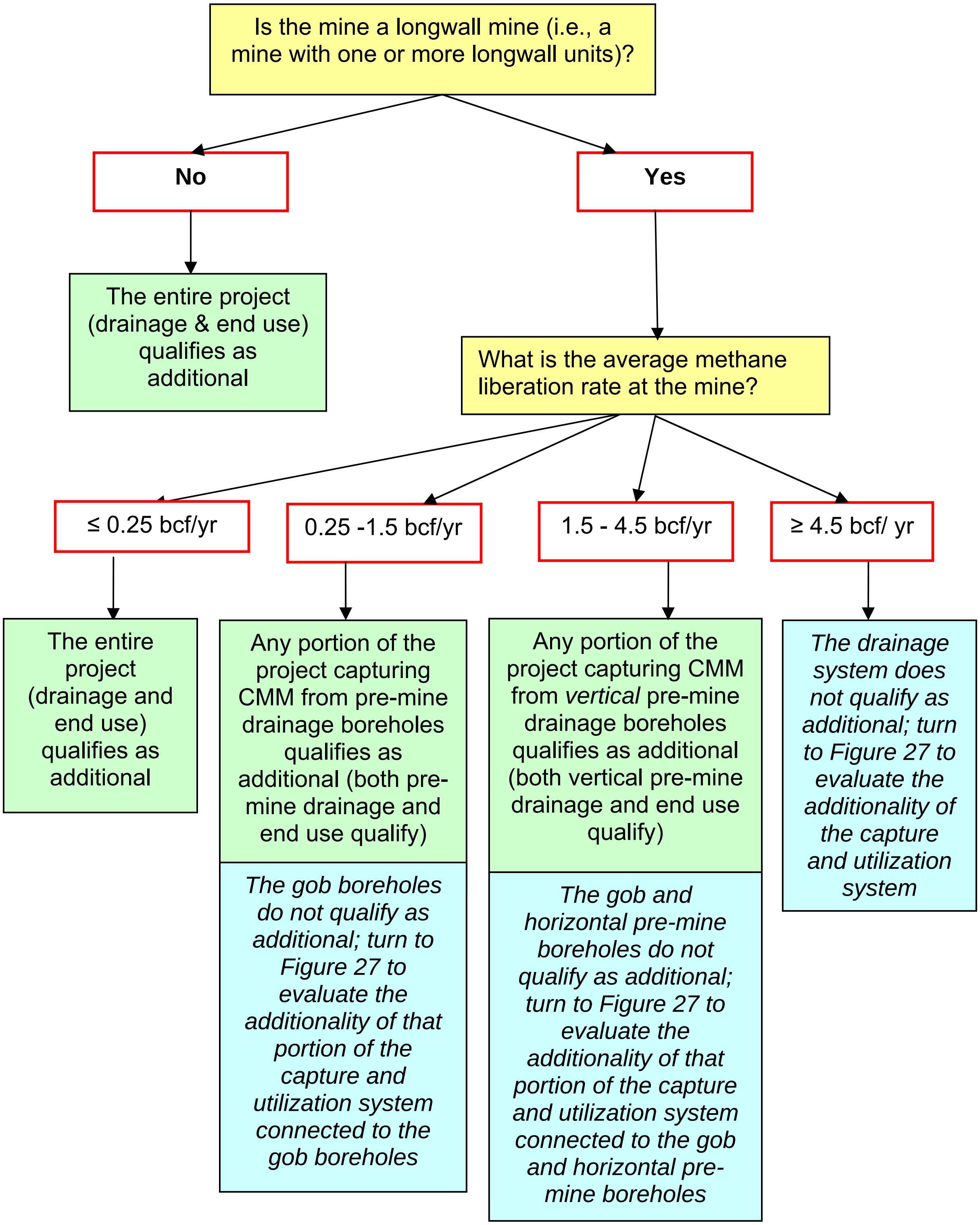
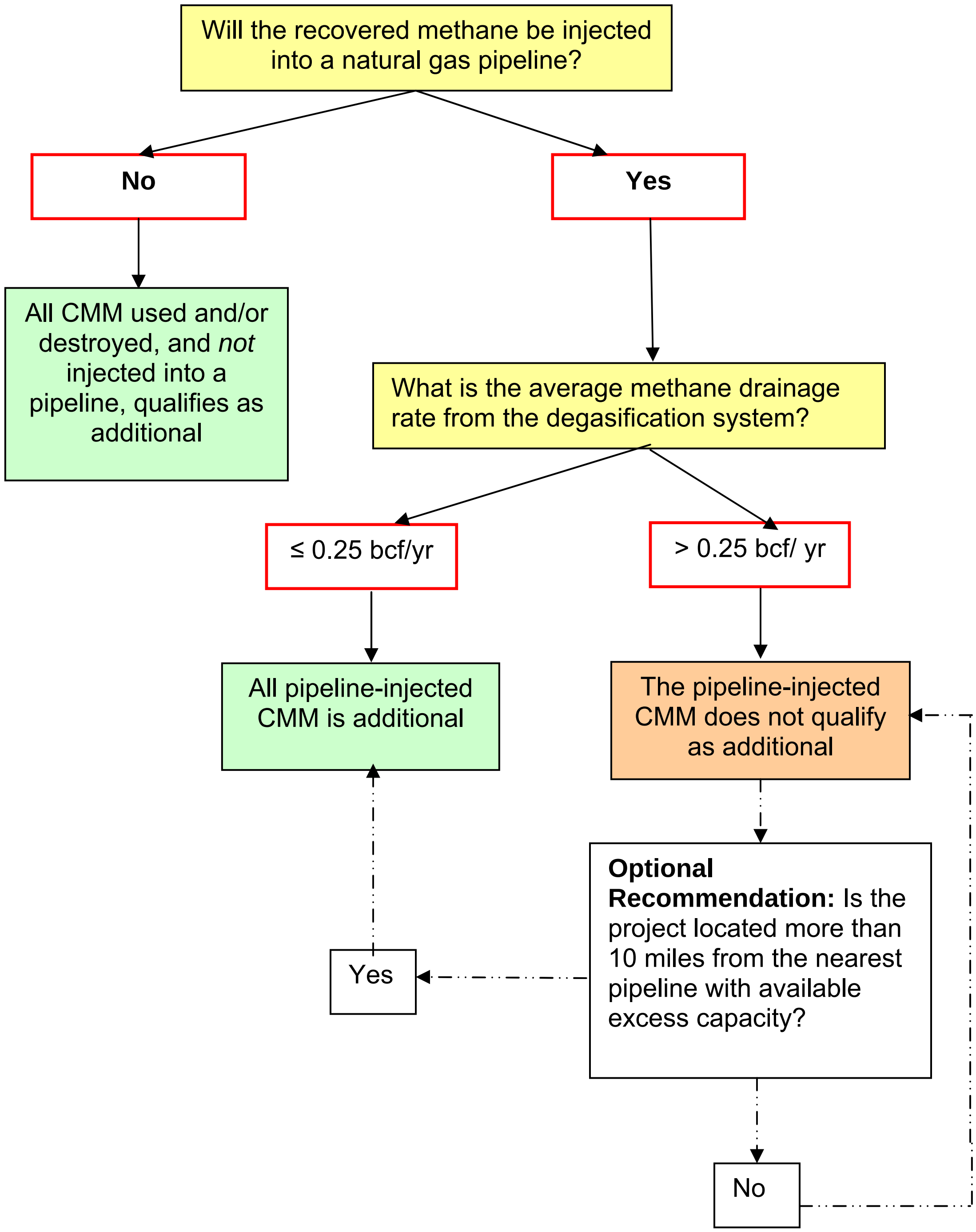


Figure 27 - Decision Tree for Applying Tentatively-Proposed Common Practice Standards to an MC Project



- If the annual methane liberation is ≥4.5 billion cubic feet per year, the project developer would proceed to Figure 27, where the entire project is treated as an MC project.

Section 4.2.2 below, “Application of the Common Practice Standards,” presents alternative approaches for estimating the annual average methane liberation rate needed to complete the decision process illustrated in Figure 26.

For MC projects, and for MDC projects that must, based on Figure 26, be treated wholly or in part as MC projects, the project developer would follow the decision process illustrated in Figure 27. The first step in this process is to answer the question “Will the recovered methane be injected into a natural gas pipeline?” If the answer is “no” for all or a portion of the CMM, then all of the CMM used and destroyed, but not injected into a pipeline qualifies for credits. For any CMM that *is* injected into a pipeline, a second question must be addressed: “What is the average methane drainage rate from the degasification system?” If the average methane drainage rate of the whole system is 0.25 billion cubic feet per year or less, the pipeline-injected CMM will qualify for credits. If the average methane drainage rate exceeds 0.25 billion cubic feet per year, the pipeline-injected CMM will not qualify for credits. Note, however, that in the latter case Figure 27 includes an *optional* third step. In this third step, the following question would be addressed: “Is the project located more than ten miles from the nearest pipeline with available excess capacity?” If the answer to this question is “yes,” the pipeline-injected CMM *would* qualify for credit; if “no” the CMM would not qualify. Note that we are *not* recommending that this third step be incorporated in the decision process for MC projects, because the available data is, in our opinion, not sufficient to enable us to specify a robust mileage threshold. However, we did want to present the third step as a possible option, as we are convinced that at *some* mileage threshold (not necessarily ten miles) a pipeline project will become additional (because the cost of constructing the feeder line to the pipeline will become prohibitive). The Reserve may therefore want to consider including the third step, perhaps at a more conservative threshold (e.g., 15 miles or 20 miles).

Section 4.2.2 below, “Application of the Common Practice Standards,” presents alternative approaches for estimating the annual average methane drainage rate needed to complete the decision process for MC projects illustrated in Figure 27.

As noted in the preceding chapter, the common practice standards for MDC and MC projects, summarized above and illustrated in Figures 26 and 27, should be viewed as our *tentative* recommendations. In the following section, these tentative standards are subjected to further evaluation, which, as we shall see, leads us to recommend a couple of (relatively minor) adjustments to the standards. The recommendations presented at the end of the next section represent our final proposed standards.

4.2 Evaluation of the Proposed Common Practice Standards

The common practice standards summarized in Figures 26 and 27 are, admittedly, based on a relatively small number of observations. However, it is important to recognize that this is not a "small sample" problem; rather it is the *population* of mines that uses drainage, with or without CMM capture and utilization, which is small. With the exception of a very small number of mines with missing data that were deleted from our database, we believe our analysis covers the entire population of gassy U.S. underground mines. Although we cannot be certain that the original MSHA and EPA databases used as our sources provide comprehensive coverage of all gassy mines, all mines with drainage, and all mines with capture and utilization, this is the intent of these databases and we have no reason to believe that there are significant deficiencies in their coverage.

Thus, while our analysis necessarily rests on a small set of observations, it is nonetheless representative of the population. By pooling our data across eight years (2000-07), we were able to increase the number of mines covered in our analysis, as well as reduce the impact of short-term fluctuations in a mine's methane liberation, drainage and/or production rate on our analysis. But beyond pooling the data, there are few if any viable means of increasing the number of observations used in our analysis. We did consider the possibility of adding data from other countries, but ruled this approach out because we believe that the geologic conditions, mining methods, and economics of mining and CMM recovery are too variable across national borders to enable the application of non-U.S. data to an analysis of common practice within the U.S.

4.2.1 A Test of the Standards

Although we believe that our database is as large as possible given the limitations in the size of the population, it nonetheless remains the case that the proposed common practice standards rests on a very limited number of observations. Partly for this reason, we conducted further analyses to evaluate the standards against certain key criteria. Specifically, a robust additionality test should meet two key objectives:

- It should *not* award credits to projects that are business-as-usual (BAU) and that will be implemented with or without credits; and

- It should *incentivize* the development of projects that are additional to the BAU baseline, which otherwise would not be implemented without emission reduction credits.

The Theory Behind the Concept of Additionality

The above two objectives are of such fundamental importance to the work documented in this paper that their theoretical underpinning is worth further discussion at this point. Both objectives serve the ultimate goal, which is to reduce GHG emissions below a projected BAU baseline of what they otherwise would be, in a cost-effective manner. By incentivizing emissions-reducing projects that would not occur without the award of credits, emissions are reduced against the projected BAU baseline. Furthermore, when such projects are undertaken because they are profitable with the addition of the revenue stream provided by the credits, the emission reductions are achieved in a less costly manner than might otherwise be the case. This market-based approach to reducing emissions, which enables emissions-reduction credits to flow to those projects that become economically feasible with the addition of the credits, fosters a (relatively) low-cost solution to climate change that benefits both the environment and the economy.

However, there is a significant risk with this market-based approach that must be carefully guarded against. If credits are awarded to BAU projects that would be implemented even without the credits, then emissions will not be reduced relative to the projected BAU baseline. This follows from the fact that such BAU projects are *included* in the BAU baseline. This is not to suggest, in any way, that such projects are not "good for the environment." Much of the confusion surrounding the concept of additionality stems from the tendency to equate additional projects with projects that are good for the environment, and non-additional projects with projects that are somehow bad for the environment. Clearly, a mine that captures and uses CMM is providing a significant environmental benefit beyond the alternative of simply venting the CMM, regardless of whether or not the project was motivated by emission reduction credits. However, the key point is that, when the CMM capture and utilization project is economically viable on its own, the mine does not need the *incentive* provided by the emission reduction credits to undertake the project. The credits, if awarded in this case, do not serve their purpose of reducing emissions. In fact, in the context of a current or future emissions cap and trade program, they will likely have the perverse effect of *increasing* emissions relative to the projected BAU baseline. Specifically, if the credits are ever used (either by the project developers themselves or by a subsequent purchaser of the credits) to meet obligations under the cap, then the final user of the credits will be able to *increase* emissions elsewhere relative to what they otherwise would have been had the credits not been awarded.[60] In this situation, the credits will have failed to reduce emissions beyond what would have happened anyway when they were first awarded, and they will subsequently enable emissions to increase beyond what they would otherwise have been. For this reason, project offset credits, if awarded in sufficient quantities to projects that do not need the incentive provided by the credits in order to be undertaken, have the very real potential to undermine and subvert national or international emission reduction goals. A robust additionality test should thus prevent credits from being awarded to projects that do not need them, while at the same time incentivizing truly additional projects that do need credits to become an economically viable investment.

Furthermore, while both of these goals are very important, we believe, strongly, that a robust additionality test must err on the side of caution in awarding credits. Again, the overarching purpose of emission reduction credits is to *reduce* emissions in a cost-effective manner. However, as we have seen, emission reduction credits can have the perverse effect of *increasing* emissions, thereby subverting in a fundamental way their basic purpose. This risk, we believe, is very real and very significant, due to certain asymmetries in the impact of errors arising from the application of additionality tests.

[60] Not all emission reduction credits will necessarily be used in this manner; a certain percentage may be retired, e.g., by environmental NGOs.

It must be recognized, at the outset, that a perfect additionality test is not attainable. Any practical additionality test will at least occasionally produce false results, or errors. The key to developing a robust test is to minimize the potential for errors—especially *systemic* errors. One of the key criteria that should be used in assessing or designing any quantitative estimation methodology is the methodology's potential for yielding biased results. With respect to project offsets estimation methodologies, the potential for errors in emission reduction estimates at the project level is always a concern, but it is the extent to which these errors fail to cancel when summed *across* projects that has the potential to either subvert national and international emission reduction goals or significantly increase the costs of meeting these goals. Of the various standard elements comprising offsets methodologies (e.g., baseline development, monitoring, etc.), the test for additionality may be a particularly potent source of biased results. In part, this potential for bias is rooted in the very nature of additionality—specifically, the fact that the additionality determination influences the decision of whether or not to proceed with a project. Errors arising from the application of additionality tests are of two types. First, when a BAU, non-additional project is erroneously classified as additional, the credits awarded to the project will, in their entirety, represent an overestimation of emission reductions relative to the projected BAU baseline. However, in the case of the second type of classification error (when an additional project is erroneously determined to be non-additional), in many cases it is likely that the additionality determination in and of itself will cause the project developers to abandon the project. While the motives for undertaking additional projects may include altruism as well as a desire for intangible rewards (e.g., enhancement of a corporation's reputation for environmental stewardship), certainly some, if not most, additional projects may be motivated primarily or solely by the desire to earn offset credits. In fact, the fundamental purpose of offset credits is to motivate the implementation of additional projects. Those additional projects motivated by the desire to earn credits will not be undertaken if they are erroneously classified as non-additional and denied the opportunity to earn credits. Such projects will not be awarded credits, they will not generate emission reductions (because they will not be undertaken), and hence the erroneous classification of these projects will *not* lead to any errors in the sum total of offset credits awarded across all projects (although in the context of an emissions cap and trade program the erroneous classification *will* cause an increase in the costs associated with reducing emissions, by preventing these additional projects from proceeding). Hence even if the additionality test itself is unbiased (i.e., even if the test misclassifies an equal percentage of additional and non-additional projects), biases will likely arise because the excess in the amount of credits awarded to misclassified non-additional projects (relative to the emission reductions of zero generated by these projects) will not be offset by a corresponding underestimation of the quantity of credits awarded to misclassified additional projects (because the latter projects will not be implemented, they will not generate any emission reductions, and they will not receive any credits). There thus exists a fundamental asymmetry in the effect of additionality classification errors that may be expected to result in an overestimation of emission reductions, and an excess of awarded credits, across all offset projects that are undertaken.

This tendency towards overestimation is likely amplified by economic considerations, which will cause project developers to favor non-additional over additional projects. Given a choice between submitting an additional project or a non-additional (BAU) project for offsets credit, a project developer may be expected to prefer the latter, because the latter will, by definition, be economically feasible even without the credits, while the former will be sub-economic without the credits. In short, non-additional projects can be expected to be more profitable than additional projects. Thus in addition to the biases arising from the classification errors discussed above, we might expect biases in the *selection* of projects submitted for emission reduction credits by project developers. If more BAU than additional projects are submitted for approval, then even a non-biased additionality test that misclassifies additional and non-additional projects in equal percentages will yield a greater number of non-additional projects classified as additional than vice versa. Thus project selection biases exhibited by project developers, and reflecting the differences in the relative economics of additional and non-additional projects, may exacerbate the asymmetries arising from classification errors. It should be emphasized that there is no need to assume any deliberate intent on the part of project developers to game the system in order to posit a selection bias in favor of non-additional projects. On the contrary, given that additionality is a very complex and obscure concept, that many BAU projects are in fact good for the environment even though they may not be additional, and that project developers may quite understandably have a favorable view of their own projects, we might expect developers acting entirely in good faith to submit non-additional projects for approval without recognizing the error.

To these considerations we should add a third important point—when non-additional projects are erroneously classified as additional, the resulting errors in the amount of credits awarded are large—indeed, they are invariably equal to 100 percent of the emission reduction estimate developed for the project. Taken together, these considerations lead us to conclude that of all the standard elements comprising emission reduction offset methodologies, the additionality determination is likely to prove the most prone to errors leading to significantly biased estimates of emission reduction offsets at the national or international levels. By the same token, the additionality test has the greatest potential to discourage additional projects from being undertaken (thereby increasing emission reduction costs under a cap), when errors lead to the classification of such projects as non-additional. The latter errors, when they occur, will tend to prevent offset credits from meeting their goal of lowering the costs of reducing emissions. However, the former errors have the more perverse effect of causing emissions to *increase*—the exact opposite of the goal of *reducing* emissions. The risk of this perverse outcome is significant, given (1) the asymmetries in the effect of additionality classification errors; (2) the potential for biases in project selection arising from the relative economics of additional versus non-additional projects; and (3) the certainty that emission reduction estimation errors resulting from the misclassification of non-additional projects as additional are always very large (in fact 100 percent). It is this significant risk of a perverse *increase* in emissions, resulting from the inappropriate awarding of offset credits to projects that do not need the credits, that leads us to believe that a robust additionality test should err on the side of caution in awarding credits. Emission reduction credits have monetary value precisely because of their potential to serve as permits to emit GHGs; great care must be taken to limit the awarding of these emissions permits to projects that truly need them or they will likely cause emissions to increase.

The Test and the Underlying Assumptions

To summarize, then, a robust additionality test should first and foremost prevent credits from being awarded to projects that are BAU and will be implemented anyway, while also incentivizing projects that need the credits in order to proceed. Although both of these goals are important, if both cannot be met it is preferable to err on the side of caution in awarding credits.

To assess how well the proposed common practice standards meet these two criteria, SAIC tested the above recommended common practice standards for MDC and MC projects by applying them to each gassy mine in our database. This analysis enabled the determination of which mines would qualify for credits either for their existing projects or for projects they could implement in the future. If the common practice standards successfully meet the two objectives, we expect:

- The majority of the mines *without* capture and utilization projects to qualify for credits for new projects; and

- The majority of the mines *with* capture and utilization projects to be disqualified for credits for their existing projects.

The assumptions underlying these expectations are as follows:

- Most gassy mines that are *not* currently draining and/or capturing methane are not doing so because such projects are not BAU; and

- Most gassy mines that *are* currently capturing and using methane are doing so because it makes economic sense to do so, even without emission reduction credits (i.e., they are BAU and require no further incentives).

The justification underlying the first assumption above should be clear. If projects *could be* but *are not* being undertaken at present, these possible projects are by definition not BAU—for if they were BAU and economically justifiable without credits they would be undertaken. It is possible that some mines have not yet implemented capture and utilization projects, but are planning to do so. However, presumably the majority of mines without existing projects have no plans to implement future projects. With regard to the second assumption, presumably most projects in operation at any given point in time are business as usual. In fact, the assumption that existing projects tend to be BAU is implicit in the common practice approach to setting performance standards. That said, it is entirely possible that some existing capture and utilization projects are additional, and are receiving emission reduction credits under a program with a robust additionality test. However, as shown in Table 11, most of the currently existing projects (specifically, nine of the seventeen CMM utilization projects in operation during the 2000-07 timeframe) were implemented in or prior to 1995—i.e., well before the initiation of official programs offering offset credits with monetary value. The original motivation of these older projects could not have been the opportunity to earn offset credits, and hence these projects are most likely not additional. Only six of the seventeen projects were initiated in the current decade, as a significant market for carbon offsets began to emerge. If some of the current projects are in fact additional, these additional projects are likely to represent some subset of the latter six mines.

Table 11 – Drainage and Capture/Use System Implementation Dates

System Implementation Date	Number of Mines with:	
	CMM Drainage Systems	CMM Capture and Use Systems
1995 or Earlier	17	9
1996 to 1999	2	2
2000 to 2007	9	6
Total	28	17

However, it seems improbable that all six of these newer projects required the incentive of emission reduction credits in order to be undertaken. This follows from the likelihood that the older projects were undertaken for the sole purpose of earning revenues from the sale of the CMM to pipelines. If natural gas prices alone were sufficient to motivate the initial development of *all* of the older projects, it seems reasonable to assume that these prices were sufficient in and of themselves to justify the development of at least *some* of the newer projects—especially since wellhead gas prices have increased dramatically since 1995 (approximately tripling by 2007—the year two of the six newer projects got their start). In short, while some of the currently existing projects may well be additional, a consideration of project start dates and wellhead price trends suggests that additional projects are not likely to be in the majority.

Test Results

Tables 12 and 13 present the results of our test of the proposed common practice standards. Table 12 considers what would happen if gassy mines that currently do *not* capture and utilize CMM were to develop new CMM projects and submit them to an additionality test using the proposed standards. To understand the test results, it is necessary to consider each row of data in the table in some detail.

The first row shows the test results for gassy room and pillar mines. There are 103 such mines in our database. As we have seen, none of these mines currently employ CMM drainage, let alone capture and utilize the CMM. Applying the standards for MDC projects shown in Figure 26, we find that *all* such projects undertaken at room and pillar mines will automatically qualify as additional. Hence all 103 gassy room and pillar mines in our database would qualify for credits were they to undertake MDC projects in the future. All 103 mines would also qualify for credits if they already had installed

Table 12 - Evaluation Test Results for Mines without Existing Capture and Utilization Projects

Type of Gassy Mine	**Total No. of Mines**	**MDC Projects**			**MC Projects**	
		No. that Could Qualify an MDC Project	**No. that Could Qualify Pre-Mining Only as an MDC Project**	**No. that Could Qualify *Vertical* Pre-Mining Only as an MDC Project**	**No. that Could Qualify Pipeline Project as an MC Project**	**No. that Could Qualify Other End Use Project as an MC Project**
Room & Pillar Mines without Drainage	103	103	--	--	≥76	103
Longwalls without Drainage	25	11	11	3	≥11	25
Longwalls with Gob Drainage *Only*	7	0	3	4	4	7
Longwalls with Gob and Horizontal Pre-Mine Drainage	2	0	0	2	1	2
Longwalls with All 3 Drainage System Types	0	NA	NA	NA	NA	NA

drainage systems and were to undertake MC projects involving end uses other than sales to natural gas pipelines. Furthermore, although we do not have the methane *drainage* rate data needed to determine whether MC pipeline projects undertaken at these mines would fall below the 0.25 billion cubic foot per year threshold, we can note that 76 of the mines have total annual methane *liberation* rates of less than 0.25 billion cubic feet. Clearly the amount of methane that could be drained from these mines cannot exceed each mine's total methane liberation rate; hence we can conclude that *at least* 76 of the 103 room and pillar mines would be able to qualify MC pipeline projects as additional using the proposed standards.

The second row of Table 12 shows that there are 25 gassy longwall mines that currently do not use drainage systems. Eleven of these mines have production-normalized methane liberation rates less than 0.25 billion cubic feet per year. Hence, as per the common practice standards illustrated in Figure 26, if the original 25 mines were to implement MDC projects including gob, pre-mining horizontal and/or pre-mining vertical boreholes, 11 would fully qualify for credits. Of the remaining fourteen mines, eleven would be able to receive credit for that portion of the CMM captured and used from pre-mining boreholes, and three would receive credit for CMM from *vertical* pre-mining boreholes. All 25 longwalls without drainage would be able to qualify MC projects involving end uses other than pipeline sales, and at least eleven of the mines would be able to qualify MC pipeline projects.

The third row indicates that there are seven longwall mines that currently have drainage systems consisting exclusively of gob boreholes. If these mines had installed CMM capture and use systems when they implemented their drainage systems, none of the capture and use projects would have *fully* qualified for credits as MDC projects. However, if these mines were to expand their drainage systems to include horizontal and vertical pre-mining boreholes, three of the mines would qualify for credits from all of the pre-mining boreholes, and the remaining four mines would be able to receive credits for the CMM captured from the vertical boreholes. Additionally, four of the seven mines could receive credits for MC pipeline projects, and all seven would be credited for MC projects involving end uses other than pipeline injection.

The fourth row of Table 12 indicates that there are two longwall mines that currently have drainage systems combining gob with pre-mining horizontal boreholes. If these mines had installed CMM capture and use systems when they implemented their drainage systems, neither of the capture and use projects would have *fully* qualified for credits as MDC projects. However, if these mines were to expand their drainage systems to include horizontal and vertical pre-mining boreholes, both mines would be able to receive credits for the CMM captured from the vertical boreholes. Additionally, one of the mines could receive credits for an MC pipeline project, and both mines would be credited for MC projects involving end uses other than pipeline injection.

Finally, the fifth row of Table 12 indicates that there are no mines with all three borehole types that do not capture and use their methane; hence we cannot test the common practice standards for this category of mines.

To summarize the test results shown in Table 12:

- All MDC projects, all MC non-pipeline projects, and most MC pipeline projects undertaken at room and pillar mines would qualify as additional under the proposed standards.

- Eleven of the twenty five gassy longwall mines currently without drainage systems would receive full credit for new MDC projects, and the remaining fourteen mines would receive partial credit (specifically for CMM captured from pre-mining boreholes). In addition, at least eleven of the mines would receive credit MC pipeline projects, and all of the mines would be credited for undertaking MC projects involving end uses other than pipeline sales.

- Of the nine longwall mines with gob only or gob and horizontal pre-mining boreholes, three could receive credit by capturing the methane currently being vented from the horizontal boreholes, and six could receive credit by expanding their drainage systems to included vertical pre-mining boreholes with capture and use. Five of the nine mines could qualify MC pipeline projects as additional, and all nine mines could qualify MC non-pipeline projects.

Based on the above results, the proposed standards appear to do a good job of incentivizing a wide variety of new capture and utilization projects at mines that are not currently implementing such projects. Since most such new projects are likely to be additional, the proposed standards appear, based on this evaluation, to satisfy one of the two main objectives of a robust additionality test.

To evaluate the proposed standards against the second key objective, the ability to screen out projects that are BAU, it is necessary to repeat the prior evaluation for mines *with* existing capture and utilization projects. Table 13 shows the results of this analysis. Specifically, the table shows what would have happened if mines with existing projects had submitted these projects for credits using the proposed common practice standards. It also shows what *would* happen if these mines were to expand their existing projects to include either more drainage techniques (e.g., pre-mining) or more end uses. Note that the red cells indicate the current elements of the existing projects. The green cells indicate elements that are *not* included in the existing projects; i.e., these cells represent opportunities for expanding the existing projects. Finally, the yellow cells identify project elements that are already included in the existing projects for some mines, but not all mines. Thus, for these yellow-coded cells, we must deal with tradeoffs between incentivizing additional project expansions while screening out non-additional projects.

The first row in Table 13 indicates that there are currently three projects that capture CMM from gob boreholes for sale to pipelines. Had these projects been submitted for credits under the proposed standards, none of them would have qualified for credits as MDC projects, nor would any of the CMM captured by these projects and sold to

Table 13 - Evaluation Test Results for Mines with Existing Capture and Utilization Projects

Type of Gassy Mine	Total No. of Mines	MDC Projects			MC Projects	
		No. that Could Qualify an MDC Project	No. that Could Qualify Pre-Mining Only as an MDC Project	No. that Could Qualify *Vertical* Pre-Mining Only as an MDC Project	No. that Could Qualify Pipeline Project as an MC Project	No. that Could Qualify Other End Use Project as an MC Project
Gob *Only* Drainage, Pipeline	3	0	0	2	0	3
Gob *Only* Drainage, Non-Pipeline *Only*	1	0	0	1	0	125
Gob and Horizontal Pre-Mine Drainage, Pipeline	4 (1 w/ other End Use	0	0	4	0	4 (1 w/ other End Use
Gob and Horizontal Pre-Mine Drainage, Non-Pipeline *Only*	1	0	0	0	0	1
All 3 Drainage System Types, Pipeline	8 (1 w/ other End Use	0	0	1	0	8 (1 w/ other End Use
All 3 Drainage System Types, Non-Pipeline *Only*	0	NA	NA	NA	NA	NA

pipelines have qualified for credits as MC projects. However, were these mines to expand their end uses to include non-pipeline as well as pipeline project types, the CMM captured for the non-pipeline uses *only* would have qualified for credits. Furthermore, if the mines extended their drainage and capture systems to include pre-mining vertical boreholes as well as the pre-existing gob boreholes, two of the three mines would qualify for credits for that portion of the CMM captured from the new boreholes. Thus for this group of mines, the proposed standards do a good job of screening out existing, likely BAU projects, while at the same time incentivizing at least some types of expansions to these projects; i.e., the standards satisfy both of the key objectives of a robust additionality test.

The second row in Table 13 shows 1 project capturing CMM from gob boreholes, for non-pipeline uses. This project would not have qualified as an MDC project under the proposed standards, but it *would* have qualified as an MC project. If the project were to be expanded to include vertical pre-mining boreholes, the CMM captured from the vertical boreholes would receive credits as an MDC project. However, if the project were expanded to include pipeline sales as well as the existing non-pipeline end uses, the portion of the CMM captured for pipeline sales would *not* receive credit under the proposed standards. Thus the results for this single project are decidedly mixed. The standards would allow the existing project to qualify for credits, while incentivizing one type of expansion (vertical pre-mining boreholes with capture) but not other types (i.e., horizontal pre-mining boreholes with capture, or pipeline sales).

The third row in Table 13 shows that there are a total of four projects that drain CMM using gob boreholes in combination with horizontal pre-mining boreholes, and sell the CMM to a pipeline. One of these projects uses CMM for another purpose as well as for pipeline sales. Had these projects been submitted for credits under the proposed standards, none of them would have fully qualified for credits as MDC projects, nor would any of the CMM captured by these projects and sold to pipelines have qualified for credits as MC projects. However, the project that incorporates non-pipeline as well as pipeline end uses would have received credit for the portion of the captured CMM *not* sold to the pipeline. If the four projects were expanded to include vertical pre-mining boreholes, all four project expansions would qualify for credits. Similarly, the three projects relying on pipeline sales exclusively would receive credit for expanding the projects to incorporate non-pipeline end uses. For this group of mines, the proposed standards do a good job of incentivizing new project expansions, while still preventing *most* of the mines from receiving credits for their existing projects.

The fourth row of the table shows one project capturing CMM from gob and horizontal pre-mining boreholes, for non-pipeline uses. This project would not have qualified as an MDC project under the proposed standards, but it *would* have qualified as an MC project. None of the potential opportunities for expanding this project would qualify for credits. The standards thus fail to screen out the existing project while also failing to incentivize project expansions. The standards thus do not meet the objectives for this group, although it is important to keep in mind that we are dealing here with a single project.

The fifth row in Table 13 shows that there are a total of eight projects that drain CMM using all three drainage techniques, and sell the CMM to a pipeline. One of these projects uses CMM for another purpose as well as for pipeline sales. Had these projects been submitted for credits under the proposed standards, none of them would have fully qualified for credits as MDC projects, nor would any of the CMM captured by these projects and sold to pipelines have qualified for credits as MC projects. However, one of the eight mines would have received partial credit as an MDC project for that portion of the CMM that is captured from the vertical pre-mining boreholes. Were these mines to expand their end uses to include non-pipeline as well as pipeline uses, the CMM captured for the non-pipeline uses *only* would have qualified for credits. Note that the one mine that already is capturing CMM for both pipeline and non-pipeline uses would also have received credits for the portion of the CMM captured for non-pipeline uses *only*, had this project been submitted for credits under the proposed standards. The proposed standards thus appear to do a good job of incentivizing new (non-pipeline) CMM uses for this group of mines, while still preventing *most* of the mines from receiving credits for their existing projects.

Finally, the sixth row of Table 13 indicates that there are no mines with all three borehole types that capture and use their methane for non-pipeline sales purposes *only*; hence we cannot test the standards for this category of mines.

Based on the results shown in Table 13, it appears that the standards do a reasonably good job of incentivizing mines with existing projects to expand those projects. Specifically:

- Seven of the nine mines with gob or gob and horizontal boreholes are incentivized to add vertical pre-mining boreholes to their drainage and capture systems (see first through fourth rows of Table 13);

- All thirteen of the mines with pipeline projects *only* are incentivized to add other end use projects (if this is feasible—i.e., if some portion of the methane is still being vented);

It should, however, be noted that the standards do not incentivize any of the four projects with gob boreholes only to expand their drainage systems to include horizontal pre-mining boreholes.

In general, the standards also appear to do a good job of screening out most of the existing projects. Specifically, only two of the seventeen existing projects would receive full credit as additional under the proposed standards (see the second and fourth rows of Table 13), while three other projects would receive partial credit (third and fifth rows). However, given our preceding discussion of the importance of erring on the side of caution when awarding credits, further careful consideration of the five projects that would qualify for full or partial credits is in order. In fact, of these five projects, two were initiated prior to 1995, strongly suggesting that these two projects are *not* in fact additional.

While it is not possible to devise an additionality determination methodology that will perform flawlessly when implemented, erring on the side of caution necessitates that, at a minimum, the common practice standards do not qualify projects that are known to be, or are highly likely to be, BAU. The fact that two existing projects initiated prior to 1995 qualified as additional under the proposed standards strongly suggests that some adjustments to these standards are warranted. One of the two projects that passed the screen uses CMM for both pipeline sales and on-site electricity generation; that portion of the CMM used by the on-site generator would qualify as additional under the proposed standards. Our proposed standards treat all CMM used for purposes other than pipeline sales as additional, even if the remaining portion of the CMM is injected into a pipeline. However, with one of the two "hybrid" pipeline projects qualifying as additional under the proposed standards, despite a project start date indicating that it is not in fact likely to be additional, we believe a tightening of the standards is in order. Specifically, we recommend that the originally proposed standards be adjusted such that non-pipeline use projects are accepted as additional regardless of their CMM drainage rate *only* when these projects are *not* combined with pipeline sales projects. Capture and utilization projects combining non-pipeline with pipeline use should be treated as if they are "pure" pipeline projects—i.e., accepted as additional only if the annual CMM drainage rate falls below the threshold of 0.25 billion cubic feet per year. Although this recommended adjustment to the originally proposed standards will remove the incentive for current pipeline-only projects to expand their CMM uses beyond pipeline sales, it is not clear how many such projects, if any, are in fact venting excess methane and could therefore benefit from such an incentive. In any event, we believe that the need to err on the side of caution dictates a tightening of the proposed standards in this situation, despite the negative impact on the ability of the standards to incentivize the expansion of existing pipeline projects.

The second project that, based on project start dates, appears to be BAU uses all three drainage system types, with that portion of the CMM captured from vertical pre-mining boreholes qualifying as additional under our proposed standards. The production-normalized methane liberation rate for this mine falls just below the 4.5 billion cubic foot standard for acceptance of CMM captured from vertical pre-mining boreholes; a slight tightening of the threshold to 4 billion cubic feet would screen out this project. A reduction of the threshold from 4.5 to 4 billion cubic feet would also remove the incentive for three mines currently using gob and/or horizontal pre-mining drainage from expanding their systems to incorporate vertical pre-mining drainage. However, it should be noted that none of these three mines are currently capturing and using their CMM. Hence incentives to expand the drainage system at these three mines to include vertical pre-mining drainage with capture and use would likely be premature; a more obvious first step would be to capture and use the CMM currently being vented at these mines. In any event, we believe that, in order to err on the side of caution and reduce the possibility that non-additional vertical pre-mining drainage projects will be incorrectly judged additional under the common practice standards, a slight tightening of the threshold to 4 billion cubic feet is warranted.

To summarize, our evaluation of the common practice standards indicates that, in general, they appear to do a good job of incentivizing additional projects while screening out non-additional projects. However, two adjustments to the standards to better serve the latter objective are recommended:

- Hybrid capture and utilization projects combining pipeline injection with other CMM uses should be treated as pure pipeline MC projects, and accepted as additional only if the average annual drainage rate is less than or equal to 0.25 billion cubic feet; and

- For MDC projects, the threshold for accepting that portion of the CMM captured from vertical pre-mining drainage boreholes should be tightened from 4.5 to 4 billion cubic feet per year of total methane liberated.

The finalized recommended standards, incorporating the above two changes, are shown in Figures 28 and 29. These figures are revised, finalized versions of Figures 26 and 27. It should be noted that two of the existing capture and use projects will still fully qualify for credits under the finalized standards; however, as both of these projects were undertaken in this decade it is quite possible that they are in fact additional. The goal of our adjustments was not to screen out *all* existing projects, just those likely to be BAU based on their vintage.

As a final note, it should not be surprising that our evaluation of the common practice standards suggests they work well when applied to *existing* mines, since the standards were based on an analysis of common practice at these mines. The real test for the standards will, of course, be how well they work when applied to *future* projects at *future* mines. This will in turn depend on the degree of similarity between existing and future common practice with respect to methane drainage, capture and utilization. Our analysis of trends, presented in Chapter 1, indicates that common practice *has* been relatively stable or slow to evolve, at least over the past decade. It was for this reason that we felt justified in pooling data for 2000-07 for our analyses. However, while common practice appears to have remained fairly stable over the recent past, it should not be assumed that this stability will continue indefinitely. As existing mines age and close, they will be replaced by new mines which may or may not follow the practices common to the existing mine population. To ensure the continued relevance and robustness of the common practice standards in the future, it will be necessary to revisit the analyses documented in this report on a periodic basis. When such analyses indicate a shift in common practice, the standards presented herein should be updated to reflect the new reality.

Figure 28 - Finalized Common Practice Standards for MDC Projects

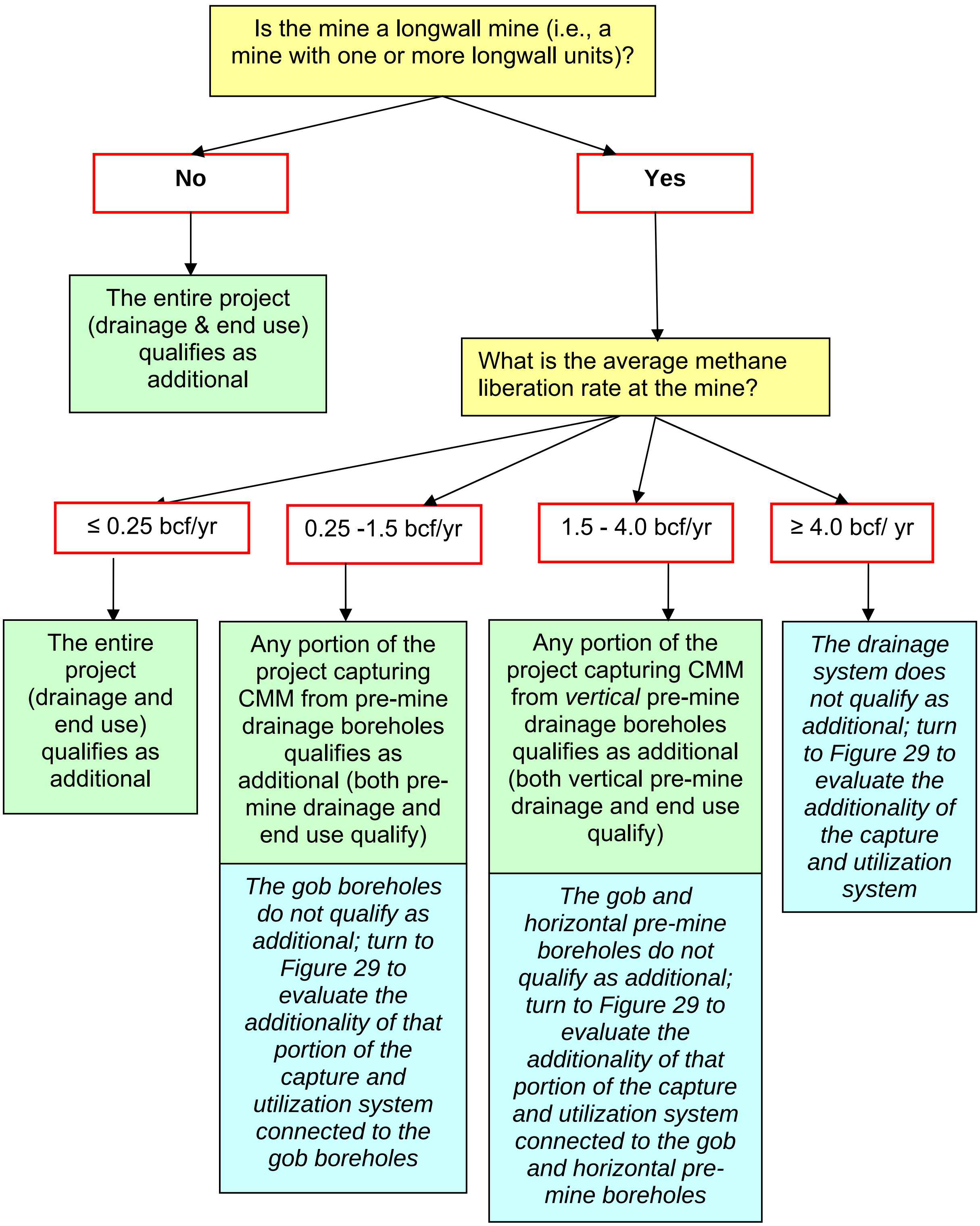
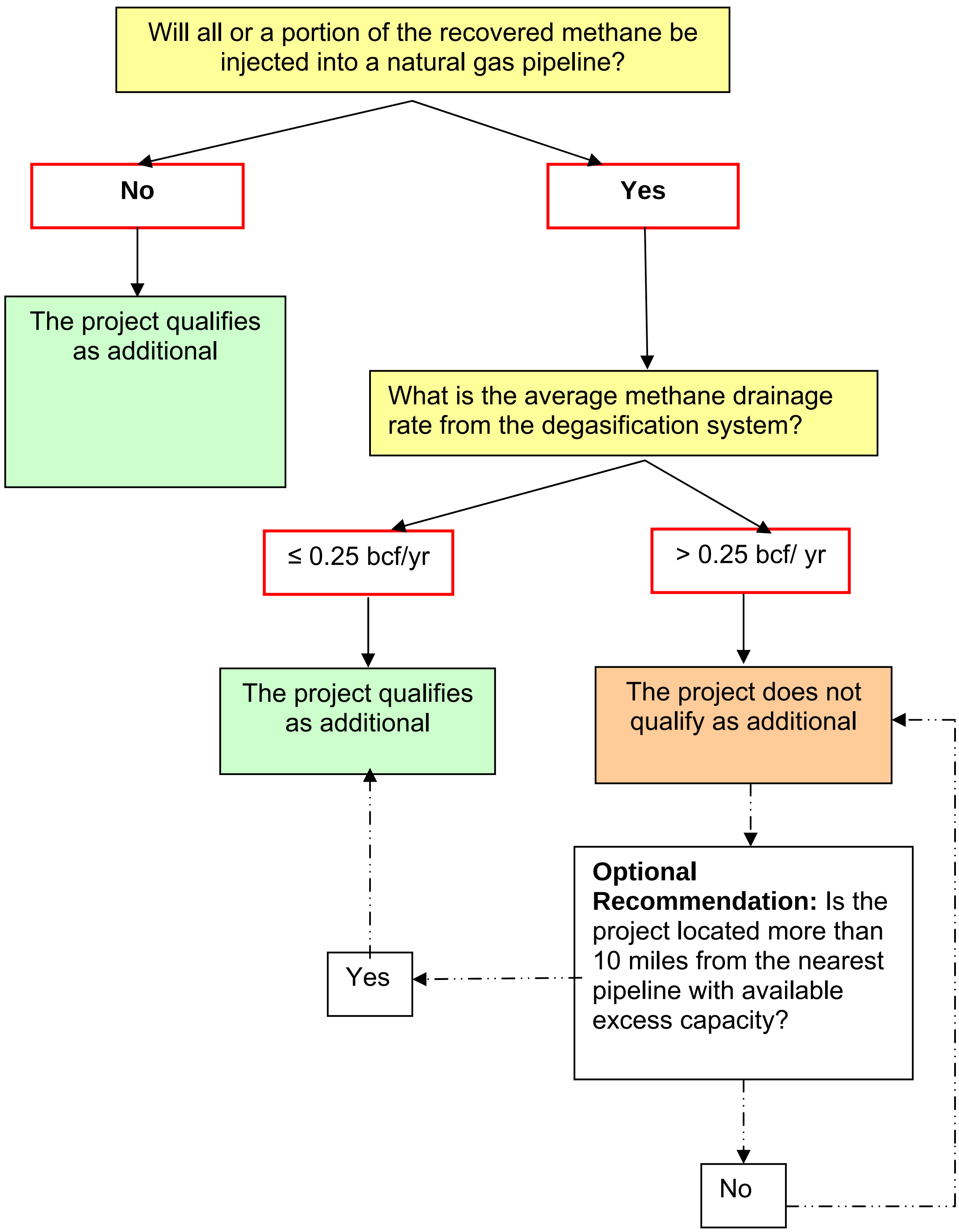


Figure 29 - Finalized Common Practice Standards for MC Projects



4.2.2 Application of the Common Practice Standards

As Figures 28 and 29 indicate, application of the common practice standards will in some cases require computation of average methane liberation and/or methane drainage rates, for comparison with threshold values to determine additionality. There are two primary alternatives for computing these values, each with its advantages and disadvantages. Selection of the best alternative for the Reserve will depend in part on the Reserve's preferences with respect to such criteria as simplicity, degree of risk for the project developer, potential for gaming, etc. Therefore, rather than recommend a specific approach, we describe each of the two main approaches, along with its pros, cons, and possible variants, in order to provide the Reserve with the information needed to make an informed choice.

Alternative 1: One-Time Determination of Additionality

Under the first alternative, the computation of methane liberation and drainage rates would follow, as closely as possible, the procedures used to compute the production-normalized rates that provided the basis for the recommended performance standard threshold values. Specifically, mines would compute their average liberation/drainage rates using historic methane liberation and/or drainage data for a period covering at least five years; an even longer time series is preferable if the necessary historic data are available. A relatively lengthy time period is recommended because methane liberation and drainage rates can fluctuate significantly as the geologic conditions encountered change; for example, the operator may encounter gassier seams, or less gassy seams, as mining progresses. Basing the methane drainage and liberation rate computations on a long time series will help to reduce the impact of atypical conditions on the results. The time period selected for the computations should be one during which the mine was operating with the full contingent of production and development units called for in the mine plan. A coal mine's life cycle generally consists of three phases. During the initial start up phase, the mine will begin operation with only one or two units to develop the area around the bottom of the shafts. Over a period of time additional development and production units will be gradually introduced until the second, full operation, phase of the life cycle is reached. During this phase of operation, which comprises most of the mine's life, all of the production and development units called for in the mine plan will be deployed. Finally, in the third (shut down) phase, development and then production units are gradually removed from operation until all mining ceases. During both the initial start-up and final shut-down periods of the mine's life, production will be significantly below the mine's planned full capacity, and since methane liberation depends heavily on production, liberation rates and drainage rates (at least from gob boreholes) will also be atypically low. Therefore, the time period selected for the computation of the mine's drainage and liberation rates should be chosen from the second, full operation phase when all of the development and production units called for in the mine plan are deployed.

Even during the second full-operation phase of the mine's life cycle, the mine may often operate at less than full capacity due, e.g., to fluctuations in market conditions, longwall moves (during which times the longwall must be taken out of production), difficult geologic conditions, equipment breakdowns, strikes, etc. However, as the requirement to keep the methane concentration below 1 percent applies at all times, a mine's ventilation and drainage systems will generally be designed to meet the regulatory requirements when methane liberation rates are at their maximum—i.e., when the mine is running at full capacity. Therefore the determination of additionality should likewise be based on methane liberation and/or drainage rates when the mine is fully utilized. In developing the common practice standards, we used production-normalized rates in which we first calculated total methane liberated (or drained) over an eight year period (2000-07), then divided this total by the total production over the same period, and finally multiplied the result by the *maximum* annual production value during the period. The result is an estimate of the mine's methane liberation (or drainage) rate under full capacity utilization conditions. (Since we did not have data on the mines' capacity, we used maximum production as a proxy for capacity.) We recommend that mine operators follow the same procedure to compute a production-normalized methane liberation (or drainage) rate for the time period selected for their mines. The resulting production-normalized values would then be compared against the threshold rates shown in Figures 28 and 29.

The above-described procedure has the advantage that it provides for a single, one-time determination of additionality that then applies to the project for its life. It also closely follows the procedure used to develop the common practice standards, thereby ensuring an "apples to apples" comparison of the liberation and drainage rate data with the thresholds. However, it is also complex, difficult to specify, and potentially difficult to confirm. For example, it may prove difficult to determine whether or not the mine operator is in fact using data collected during the full-operation phase of the life cycle, as opposed to the initial start-up phase. In fact, distinguishing the different phases of the mine life cycle, while easy at the conceptual level can prove much more difficult in practice. As just one example of the potential practical difficulties, mine plans can change and evolve over time, leading to ambiguities in the number of units that defines full operation.

Another key disadvantage is that, for some types of projects, a significant time elapse may occur between project initiation and confirmation that the project is in fact additional. Specifically, in some cases a methane capture and utilization project may be scheduled to begin operation *before* a sufficient time series of historic data has been established. In fact, in the case of vertical pre-mining drainage, a project may be scheduled to begin years in advance of the commencement of mining. While the Reserve may be able to provide some type of provisional status to such projects based on forecasted values of the methane liberation or drainage rate, using the above-described procedure, a final determination of additionality and eligibility for credits would have to be delayed until the forecasted values can be confirmed using the historical data computations outlined above. The resulting delays will put the operator at risk, in some situations for a substantial time period. For example, we might consider a mine that begins pre-mining drainage and capture/use operations two years before mining commences, and then takes three additional years to reach the full-operation phase of its life cycle. In order to generate a five-year time series of methane liberation and drainage data during its full operation phase, this example mine will need to wait ten years from the initiation of its CMM project before it will be able to prove its additionality. The CMM project will be operating at risk during this 10-year period. Nonetheless, despite the heightened risks, the time delay would be necessary under this approach to ensure that the forecasted liberation/drainage rate represents a good faith estimate on the part of the operator. It is possible that the delays in conferring approval would discourage operators from undertaking additional projects.

There are a couple of possible variants of the above-described approach, which might to at least some extent alleviate the risks to the project developer. First, since even good faith forecasts of methane liberation and methane drainage rates will be characterized by significant uncertainties, the Reserve may want to consider the establishment of tolerance ranges around the threshold values shown in Figures 28 and 29, to be used to confirm additionality for projects that are initiated prior to the establishment of a sufficient time series of historic data. For example, the threshold liberation and drainage rates for these "early-start" projects might be increased by 10 percent to allow for uncertainties in the forecasts used by the mine operator. These "higher-tolerance" thresholds would be applied only to projects undertaken prior to the establishment of a sufficient time series of historic data; projects initiated later in the mine's life cycle would be judged on the basis of the unadjusted threshold values shown in Figures 28 and 29.

As a second variant, the Reserve may wish to consider acceptance of forecasted values of methane liberation and/or drainage as the basis for the additionality determination *if* the mine operator can provide sufficient documentation to show that the forecasts were also used as the basis for obtaining project financing. However, such an approach could prove to be a "slippery slope" away from performance standards and towards a financial additionality determination.

Alternative 2: Determination of Additionality on a Continuing Basis

The second primary option to be considered would involve testing for additionality on a continuing basis, throughout the mine's life cycle and project crediting period. Under this approach, the mine operator would compare *actual* methane liberated and/or methane drained quantities in each year with the appropriate threshold values. If the actual values fall under the threshold for a given year, the mine would receive credits for the emission reductions achieved in that year. However, if in any year x the actual methane liberation and/or methane drainage amounts exceed the appropriate thresholds, credits would be discontinued for year x and for all subsequent years.

There are a number of advantages to such an approach. For one, the required data is much simpler, both to explain and to develop. This simplicity should in turn reduce the potential for errors arising from inadvertent misunderstandings, as well as deliberate attempts to game the system. Another key advantage is that this approach eliminates the need for a time delay between project initiation and the awarding of credits. This should in turn reduce the risk shouldered by project developers—although some risk will still remain, given that projects could lose the opportunity to earn credits at some point in their lives.

There are however some disadvantages to this approach as well:

- Non-additional projects could receive credits for a number of years before they exceed the threshold values that would disqualify them for further credits. For example, a mine in the initial start-up phase of its life, an under-utilized mine, or a mine operating in less gassy areas might experience lower liberation and/or drainage rates for a number of years before reaching the more normal rates that would trigger disqualification.

- Unexpected, short-term fluctuations in methane liberation and drainage rates could trigger the disqualification of an additional project. For example, a mine might encounter an unexpected, unusually gassy pocket that would throw off the annual rates in a given year.

- Improvements in project performance undertaken by the operator could cause drainage rates to exceed the threshold value. For example, if the mine operator drills more boreholes on a tighter spacing pattern, or is able to better locate boreholes based on experience with what has worked best in the past, the resulting increase in drainage rates could trigger disqualification of the project. Particularly for projects operating near the threshold, this possibility could actually act as a disincentive to improving project performance.

There are a number of modifications to the basic approach that could be introduced to address at least some of the above concerns. For example, to reduce the potential impact of fluctuations in liberation/drainage rates, the crediting period could be extended from one year to two or three years (e.g., additionality would be determined, and credits awarded, once every three years rather than annually). Another alternative would be to wait until a project exceeds its threshold two or three times before disqualifying the project. To prevent false crediting of mines during their initial start up phase, the first annual additionality determination could be delayed for two or three years. Finally, to prevent project performance improvements from triggering project disqualification, it might be possible to raise the threshold by an amount equal to the expected drainage rate improvement. However, in this case it would be necessary for the project developer to carefully document the timing and nature of all project enhancements, as well as other factors that might also impact drainage rates (such as increases in production or changes in gassiness. With some or all of the above-described enhancements, the continuing-basis approach to determining additionality might offer significant advantages relative to the one-time approach. SAIC tends to favor the continuing-basis approach (with a 3- as opposed to 1-year crediting period) for its simplicity and risk-limiting characteristics, although, again, a final choice between the two approaches should be based on the Reserve's preferences with respect to such criteria as risk, complexity, etc.

4.2.3 Updating the Common Practice Standards

As previously noted, the common practice standards developed in this chapter and illustrated in Figures 28 and 29 reflect operating practices under current economic, regulatory and technological conditions. These conditions may change in the future, potentially affecting common practice. SAIC therefore recommends that the analyses presented in this paper be updated on a periodic basis (at least once every decade, and preferably once every five years), to either confirm that common practice has not changed or to develop new standards reflecting changed conditions.

APPENDIX

Explanation of the Data Sources and Methodologies Used to Calculate the Raw Data Used in the Development of the Recommended Common Practice Standards

The common practice standards developed in this paper hinge on two key variables: the methane liberation rate and the methane drainage rate for each gassy mine. As discussed in Chapter 3, the source of the data for these variables is EPA's *Coal 07 draft* Excel file. The methane liberation and drainage rate data included in this file are used by EPA in the development of the coal mine methane emissions estimates included their annual inventory of U.S. GHG emissions. In this appendix, additional information on the original sources and/or estimations used by EPA to develop the methane liberation and methane drainage data is provided.

The methane liberation data used in the analyses documented in this report represent the sum of two separate components, both provided in the EPA's *Coal 07 draft* Excel file: (1) ventilation emissions and (2) methane vented and/or captured through drainage systems. The ventilation emissions data contained in the EPA file represent *measured* emissions provided to EPA by MSHA. MSHA samples ventilation air methane flow and concentration at least quarterly at all gassy mines using a specific VAM sampling protocol. Testing is conducted in the same underground location each time a mine's system is tested, but not necessarily under conditions representative of normal mine operations in any given quarter. The ventilation emissions data provided by the EPA represent an average of the quarterly measurements taken by MSHA at each mine. As noted by EPA in its *Profiles,*[61] the estimates of annual ventilation emissions are only accurate to the extent that quarterly samples were taken from locations and on days that are representative of average daily methane flow and concentration at the mine throughout the sampling quarter.

In contrast to MSHA's mandatory ventilation measurements, there are no requirements to measure or report emissions of methane from drainage systems. Thus, the data provided by EPA on methane drainage is composed of a number of different *estimation or measurement* sources. The sources and/or estimation procedures used are documented in EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks* report. In some cases, where the Agency is provided measurements of emissions from the drainage system by the mine operator, these measured values are used. For mines where collection systems and pipeline utilization projects are in place, the EPA obtained gas sales records from state agencies in order to estimate total drainage rates. Further, the EPA notes in the discussion of its methodology for CMM in the 1990-2007 *Inventory,* "For most mines with recovery systems, companies and state agencies provided individual well production information, which was used to assign gas sales to a particular year. For the few

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[61] US EPA CMOP. 2008. *Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines: 2002-2006*. P. 4-4.

remaining mines, coal mine operators supplied information regarding the number of years in advance of mining that gas recovery occurs,"[62] in order to properly assign reductions to the year in which they would have otherwise occurred as emissions.

In cases where no other data are available, drainage rates are estimated based upon degasification system type-specific default recovery efficiencies.

[62] US EPA. 2008. *US Inventory of Greenhouse Gas Emissions and Sinks: 1990-2007*. pg. 3-34.