Coal Mine Methane Project Protocol

Destroying Methane from Active Underground Coal Mines

Version 1.0

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Acknowledgements

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Abbreviations and Acronyms

ACM	Approved consolidated baseline and monitoring methodology under CDM
CDM	Clean Development Mechanism
CH_4	Methane
CMG	Coal mine gas
CMM	Coal mine methane
CNG	Compressed natural gas
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
CRT	Climate Reserve Tonne
EIA	Energy Information Administration
GHG	Greenhouse gas
HMM	Coal mine methane from horizontal pre-mining
ISO	International Organization for Standardization
IPCC	Intergovernmental Panel on Climate Change
LNG	Liquid natural gas
MSHA	Mine Safety and Health Administration
NMHC	Non-methane hydrocarbon
NOV	Notice of Violation
NOVA/COI	Notification of Verification Activities/Conflict of Interest
PMM	Coal mine methane from post-mining (gob wells)
QA/QC	Quality assurance/quality control
SMM	Coal mine methane from surface pre-mining
SSR	Sources, sinks and reservoirs
UNFCCC	United Nations Framework Convention on Climate Change
VAM	Ventilation air methane
WBCSD	World Business Council for Sustainable Development
WRI	World Resources Institute

1 Introduction

The Climate Action Reserve (Reserve) Coal Mine Methane Project Protocol provides guidance to account for, report and verify greenhouse gas (GHG) emission reductions associated with destroying methane from active underground coal mines that would have otherwise been vented to the atmosphere from degasification systems, including drainage systems and ventilation systems. The protocol focuses on quantifying the change in methane emissions, but also accounts for effects on carbon dioxide emissions.

The Climate Action Reserve is a national offsets program working to ensure integrity, transparency and financial value in the U.S. carbon market. It does this by establishing regulatory-quality standards for the development, quantification and verification of GHG emissions reduction projects in North America; issuing carbon offset credits known as Climate Reserve Tonnes (CRT) generated from such projects; and tracking the transaction of credits over time in a transparent, publicly-accessible system. Adherence to the Reserve's high standards ensures that emission reductions associated with projects are real, permanent and additional, thereby instilling confidence in the environmental benefit, credibility and efficiency of the U.S. carbon market.

The Reserve operates as a program under the similarly named nonprofit organization. Two other programs, the Center for Climate Action and the California Climate Action Registry, also operate under the Climate Action Reserve.

Project developers that install coal mine methane destruction technologies use this document to register GHG reductions with the Reserve. The protocol provides eligibility rules, methods to calculate reductions, performance-monitoring instructions, and procedures for reporting project information to the Reserve. Additionally, all project reports receive annual, independent verification by ISO-accredited and Reserve-approved verification bodies. Guidance for verification bodies to verify reductions is provided in the Reserve's Verification Program Manual and Section 8 of this protocol.[1]

This protocol is designed to ensure the complete, consistent, transparent, accurate, and conservative quantification and verification of GHG emission reductions associated with a coal mine methane project.[2]

[1] With previous project protocols, the Reserve has produced a separate verification protocol for each project reporting protocol. Reporting and verification guidance is now included in one document. Upcoming revisions to already existing project protocols will implement this programmatic change.
[2] See the WRI/WBCSD GHG Protocol for Project Accounting (Part I, Chapter 4) for a description of GHG reduction project accounting principles.

2 The GHG Reduction Project

2.1 Background

Methane is formed during the same geologic process that converts vegetative matter to coal; coal mining and post-mining processes release this methane from the coal and surrounding rock to the atmosphere. 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 the seam depth.

When combined with air in concentrations of 5 to 15 percent, methane released by mining activity is explosive within the mine atmosphere. All underground coal mines in the United States 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). Under the MSHA regulations, methane concentrations must be kept below 1 percent at the working face. Degasification is therefore an integral and critically important component of the underground mining process. Two primary degasification techniques are available to the operator: ventilation and methane drainage. Methane emissions are vented through mine ventilation shafts or methane drainage wells designed for the express purpose of removing the methane from the mine and venting it to the atmosphere.

Ventilation

The primary purpose of ventilation systems is to (1) dilute the methane in the mine air, and (2) remove the methane from the mine. Clean intake air is drawn into the mine from above ground 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.

The ventilation systems emit highly dilute concentrations of the methane; typically the mine air vented from return air shafts is less than 1 percent methane. In this protocol, coal mine methane in mine air emitted through ventilation systems is referred to as ventilation air methane or "VAM".

Methane Drainage

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.

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

- Surface pre-mining boreholes
- Horizontal pre-mining boreholes
- Post-mining (or gob) boreholes

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

Surface Pre-Mining Boreholes

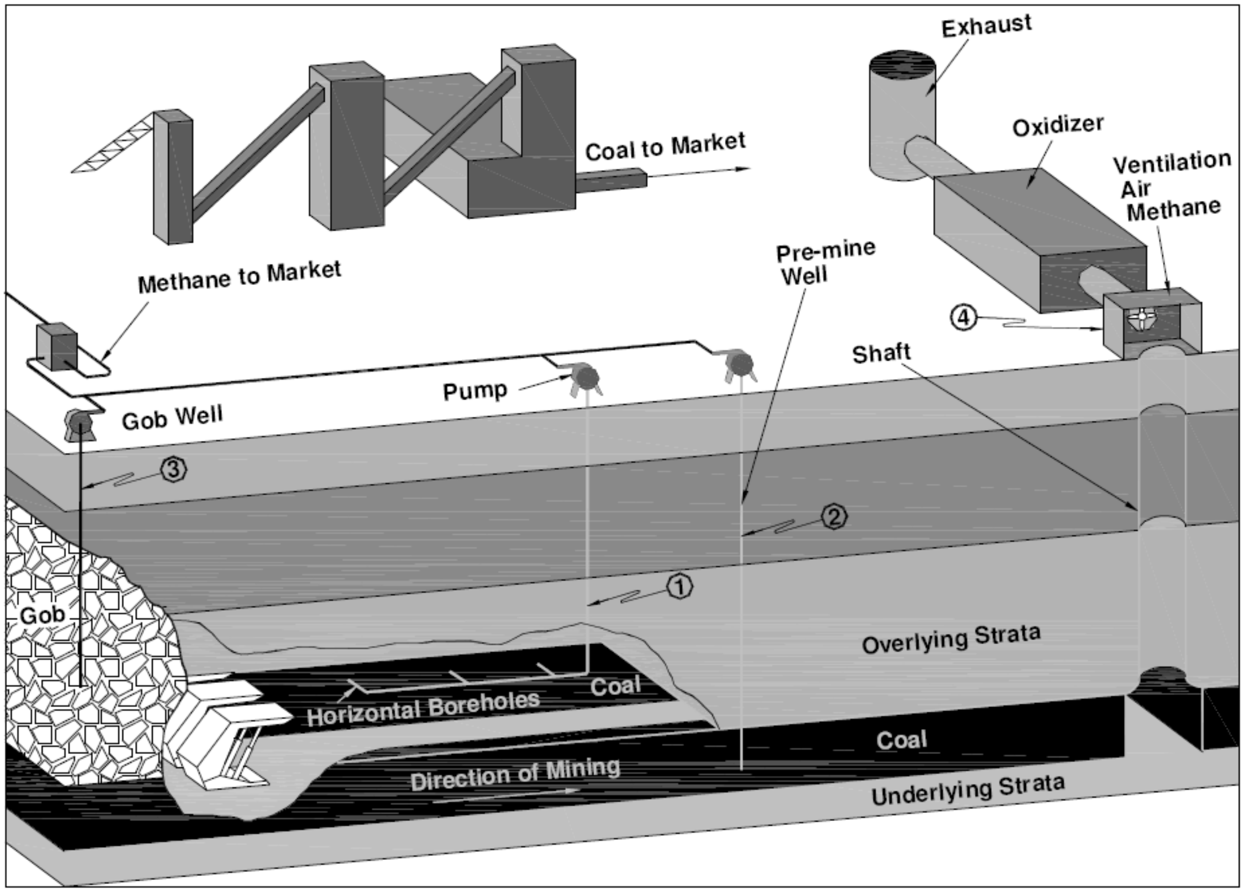
Surface pre-mining boreholes, or wells, are drilled from the surface to unmined portions of the coal seam in advance of mining (see Figure 2.1). They may be vertical, vertical to lateral, or even close to horizontal in their orientation. Surface-to-seam boreholes (otherwise known as surface-drilled directional boreholes) fall into this category. All of these surface pre-mining boreholes collect methane both from the seam itself, as well as from strata lying above the seam. Surface pre-mining wells may be drilled in locations that are not scheduled to be mined through for months or years; sometimes surface 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 surface wells produce a high quality gas that is uncontaminated with mine air. Typically gas from these wells is at least 90 percent pure methane. In this protocol, the acronym “SMM” refers to coal mine methane drained from surface pre-mining boreholes.

Horizontal Pre-Mining Boreholes

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 2.1). 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 surface pre-mining boreholes. In this protocol, the acronym “HMM” refers to coal mine methane from horizontal pre-mining boreholes.

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 2.1). 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 gases from the gob are collected via the gob well. 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, although it can be high quality early on in the life of the well. 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 1,000 Btus per cubic foot for pipeline quality natural gas). In this protocol, the acronym “PMM” refers to coal mine methane from post-mining boreholes.



1) Horizontal Pre-Mining 2) Surface Pre-Mining 3) Post-Mining and 4) VAM
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, January 2009, p 2-5.

Figure 2.1. Schematic of Degasification Types

2.2 Project Definition

For the purpose of this protocol, a GHG reduction project (project) is defined as the installation and operation of any device, or set of devices, that result in the destruction of methane gas that would otherwise have been vented to the atmosphere from an active underground mine. Eligible mines include coal mines as well as trona mines that are classified by MSHA as Category III gassy underground metal and non-metal mines. While the protocol document refers to “coal mine methane” (CMM) throughout, it may be applied to methane released through mining at Category III gassy underground trona mines.

A project must consist of either:

1. Installation and operation of a methane destruction device (or multiple devices) that destroys methane from a methane drainage system
2. Installation and operation of a methane destruction device (or multiple devices) that destroys ventilation air methane

A single project may not combine destruction of both drainage system and ventilation air methane, except under limited circumstances.[3] However, both drainage projects and VAM projects may be implemented and registered separately at the same mine. In addition, project developers may register multiple projects of the same type at the same mine, e.g. if separate destruction devices are installed at different times.

The protocol does not apply to projects that:

- Operate in surface mines
- Destroy methane from abandoned mines
- Destroy virgin coal bed methane (e.g. methane of high quality extracted from coal seams independently of any mining activities)
- Use CO_2 or any other fluid/gas to enhance CMM drainage before mining takes place

Under the terms of this protocol, the Reserve will issue CRTs only for the destruction of methane that would otherwise have been emitted to the atmosphere. Some projects may put captured CMM to beneficial use by using it to generate energy. Projects that use CMM for energy production are eligible under this protocol (since they destroy methane in the process). However, such projects will not receive credit for displacing GHG emissions associated with other fossil fuels that might have been used to produce energy. Although the Reserve does not issue CRTs for fossil fuel displacement, it strongly supports using CMM for energy production.

Version 1.0 note to users:
Under Version 1.0 of this protocol, projects that send coal mine methane off-site through a pipeline for consumption are not eligible. The Reserve is continuing work to refine the performance standard test to allow pipeline projects in Version 2.0 (expected in February 2010). At that time, the definition of a project under this protocol may change to accommodate "any set of activities that result in the destruction of methane gas" rather than "the installation and operation of any device…that result in the destruction of methane gas".

2.2.1 Drainage Projects

A drainage project is one that destroys methane that would otherwise be vented to the atmosphere from a methane drainage system. The methane drainage system may use any of the following extraction activities:

- Surface boreholes, including vertical and surface-to-seam directional drilling, located within the boundary of the mine to capture pre-mining CMM
- In-mine underground horizontal boreholes located within the boundary of the mine to capture pre-mining CMM
- Surface gob wells, underground boreholes, gas drainage galleries or other gob gas capture techniques located within the boundary of the mine, including gas from sealed areas, to capture post mining CMM

The borehole(s) that make up each project's drainage system must be defined by the project developer at the time of project submittal. The project developer must also specify what destruction device(s) is/are part of the drainage project. A single project must be explicitly defined and associated with specific boreholes and destruction devices. Multiple drainage

[3] In some cases, CMM from a drainage system is allowed to supplement a VAM project (see Section 3.4.2). In this case, a single project can consist of both drainage system and VAM methane destruction, as long as the drainage system contribution is limited to supplemental CMM.

projects may be implemented at a single mine, each with its own start date, crediting period, registration, and verification cycle. Each project's drainage system and destruction devices shall be detailed in the project diagram.

If additional boreholes are drilled and/or connected to an existing qualifying project destruction device, this is considered a project expansion. Similarly, if a new or additional destruction device is added to existing boreholes connected to an existing project destruction device, this is considered a project expansion. If a new borehole is developed and a new destruction device added, this is considered a new project.

2.2.2 Ventilation Air Methane Projects

A ventilation air methane project is one that destroys methane that would otherwise be vented from a ventilation shaft (or multiple shafts). The ventilation shaft(s) and VAM destruction device(s) that make up each VAM project must be defined by the project developer at the time of project submittal. A single project must be explicitly defined and associated with a specific shaft (or multiple shafts that are operating concurrently). Multiple projects may be implemented at a single mine, each with its own start date, crediting period, registration, and verification cycle. Each project's ventilation shaft(s) and VAM destruction device(s) shall be detailed in the project diagram.

If additional VAM destruction equipment is added to a shaft that is part of an existing project, this is considered a project expansion. If VAM destruction equipment is installed at a shaft that is not part of an existing project, this new shaft may be considered a new project or a project expansion. If the project developer chooses to define it as a project expansion, the project start date and crediting period remain the same, and a single verification will cover activities at both shafts. If the project developer chooses to define it as a new project, activities at the new shaft will have a new start date and crediting period, and will require separate verification. For a new VAM project, the VAM destruction equipment does not need to be new; it is only the ventilation shaft that must be new.

2.2.3 Non-Qualifying Devices

Non-qualifying devices are destruction devices that do not meet one or more of the eligibility rules as described in Section 3 and are located at the same mine where eligible project activities are taking place.[4] If there are any non-qualifying devices in operation at a mine, the project developer must include the non-qualifying device(s) in the project's GHG Assessment Boundary (see Section 4) and in the project diagram (see Section 7.1). Subsequent projects implemented at the same mine may exclude the same non-qualifying device(s) from their GHG assessment boundaries. In other words, if methane destruction at a non-qualifying device is accounted for by one project at a mine, it does not need to be accounted for by other projects at the same mine.

If any new non-qualifying devices become operational at the mine, these devices must be assigned to a specific project. In the case where a project developer has more than one registered project at a mine, the project developer may choose which project will account for the new non-qualifying device.

[4] Note that in Version 1.0, coal mine methane sent off-site through commercial pipeline is not eligible, but is also outside of the GHG Assessment Boundary. Because CMM sent to commercial pipeline is outside of the GHG Assessment Boundary, sources of emissions associated with commercial pipelines are not included in the project diagram.

In the case where there are multiple projects with different crediting periods at a mine, when the crediting period for a project that includes a non-qualifying device expires, the non-qualifying device must be added to the GHG Assessment Boundary of a project that is still active. Thus, all non-qualifying devices must be properly accounted for in the GHG Assessment Boundary of an active project at the mine over time.

2.3 The Project Developer

The "project developer" is an entity that has an active account on the Reserve, submits a project for listing and registration with the Reserve, and is ultimately responsible for all project reporting and verification. Project developers may be coal mine owners, coal mine operators, GHG project financiers, utilities, or independent energy companies. The project developer must have clear ownership of the project's GHG reductions. Ownership of the GHG reductions must be established by clear and explicit title, and the project developer must attest to such ownership by signing the Reserve's Attestation of Title form.[5]

[5] Attestation of Title form available at www.climateactionreserve.org/how-it-works/projects/register-a-project/documents-and-forms.

3 Eligibility Rules

Projects that meet the definition of a GHG reduction project in Section 2.2 must fully satisfy the following eligibility rules in order to register with the Reserve.

Eligibility Rule I:	Location	⟶	*U.S. and its territories*
Eligibility Rule II:	Project Start Date	⟶	*Within six months prior to project submission**
Eligibility Rule III:	Additionality	⟶	*Exceed legal requirements*
		⟶	*Meet performance standard*
Eligibility Rule IV:	Regulatory Compliance	⟶	*Compliance with all applicable laws*

* See Section 3.2 for additional information on project start date

3.1 Location

Under this protocol, only projects located at a single mine in the United States and its territories are eligible to register with the Reserve.[6]

3.2 Project Start Date

The project start date shall be defined by the project developer, but must be no more than 3 months after coal mine methane is first destroyed by the project, regardless of whether sufficient monitoring data is available to report reductions. The start date is defined in relation to the commencement of methane destruction, not other activities that may be associated with project initiation or development. For projects that involve pre-mine drainage, for example, well-drilling may commence in advance of any methane destruction; in such cases, the start date would be linked to the commencement of methane destruction, not drilling activities.

To be eligible, the project must be submitted to the Reserve no more than six months after the project start date, unless the project is submitted during the first 12 months following the date of adoption of this protocol by the Reserve board (the Effective Date).[7] For a period of 12 months from the Effective Date of this protocol (Version 1.0), projects with start dates no more than 24 months prior to Effective Date of this protocol are eligible. Specifically, projects with start dates on or after October 7, 2007 are eligible to register with the Reserve if submitted by October 7, 2010. Projects with start dates prior to October 7, 2007 are not eligible under this protocol. Projects may always be submitted for listing by the Reserve prior to their start date.

3.3 Project Crediting Period

The crediting period for coal mine methane projects under this protocol is ten years. At the end of a project's first crediting period, a project developer may apply for eligibility under a second

[6] The Reserve anticipates that this protocol could be applied throughout North America and internationally. To expand its applicability, data and analysis supporting an appropriate performance standard for other countries would have to be conducted accordingly. Refer to Appendix A for information on the performance standard analysis supporting application of this protocol in the United States.

[7] Projects are considered submitted when the project developer has fully completed and filed the appropriate Project Submittal Form, available on the Reserve's website.

crediting period. However, the Reserve will cease to issue CRTs for GHG reductions if at any point in the future CMM destruction becomes legally required at the project site. Thus, the Reserve will issue CRTs for GHG reductions quantified and verified according to this protocol for a maximum of two ten year crediting periods after the project start date, or until the project activity is required by law, whichever comes first. Section 3.4.1 defines the conditions under which a project is considered legally required, and Section 3.4.2 describes the requirements to qualify for a second crediting period.

The crediting period will also end if the mine where a project is located is declared abandoned; the Reserve will issue CRTs for GHG reductions quantified and verified according to this protocol only up until the date the mine was declared abandoned (i.e. the date when ventilation is discontinued).

3.4 Additionality

The Reserve strives to register only projects that yield surplus GHG reductions that are additional to what would have occurred in the absence of a carbon offset market.

Projects must satisfy the following tests to be considered additional:

1. The Legal Requirement Test
2. The Performance Standard Test

3.4.1 The Legal Requirement Test

All projects are subject to a Legal Requirement Test to ensure that the GHG reductions achieved by a project would not otherwise have occurred due to federal, state, or local regulations, or other legally binding mandates. A project passes the Legal Requirement Test when there are no laws, statutes, regulations, court orders, environmental mitigation agreements, permitting conditions, or other legally binding mandates requiring the destruction of coal mine methane at the project site. To satisfy the Legal Requirement Test, project developers must submit a signed Regulatory Attestation form[8] prior to the commencement of verification activities each time the project is verified (see Section 8). In addition, the project's Monitoring Plan (Section 6) must include procedures that the project developer will follow to ascertain and demonstrate that the project at all times passes the Legal Requirement Test.

As of the Effective Date of this protocol, the Reserve could identify no existing federal, state or local regulations that obligate coal mines to destroy coal mine methane.[9] If an eligible project begins operation at a coal mine that later becomes subject to a regulation, ordinance or permitting condition that calls for the destruction of coal mine methane, emission reductions may be reported to the Reserve up until the date that the coal mine methane is legally required to be destroyed. If the coal mine's methane emissions are included under an emissions cap (e.g. under a state or federal cap-and-trade program), emission reductions may likewise be reported to the Reserve until the date that the emissions cap takes effect.

[8] Regulatory Attestation form available at www.climateactionreserve.org/how-it-works/projects/register-a-project/documents-and-forms.

[9] 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 of the mine. To 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 MSHA. The Act does not require, however, that CMM be destroyed.

3.4.2 The Performance Standard Test

Projects pass the Performance Standard Test by meeting a performance threshold, i.e. a standard of performance applicable to all coal mine methane destruction projects, established on an ex-ante basis by this protocol.

There are numerous possible management options and end uses for coal mine methane, ranging from venting, to destruction by flares, to injection of the methane into natural gas pipelines. The Performance Standard Test employed by this protocol is based on a national assessment of "common practice" for managing coal mine methane. The performance standard defines those end uses that the Reserve has determined will exceed common practice and therefore generates additional GHG reductions.[10]

Drainage projects pass the Performance Standard Test if they destroy CMM through any end-use management option other than injection into a natural gas pipeline for off-site consumption (e.g. flare, power generation, heat generation, producing CNG/LNG for vehicle use, etc.).

Version 1.0 note to users:
Under Version 1.0 of this protocol, projects that send coal mine methane off-site through a pipeline for consumption are not eligible. The Reserve is continuing work to refine the Performance Standard Test to include a pipeline project performance standard in Version 2.0 (expected in February 2010).

All VAM projects pass the Performance Standard Test. Such projects may include, but are not limited to, the following end uses for VAM:

- Thermal flow reversal reactors with or without catalysts
- Volatile organic compound concentrators
- Carbureted gas turbines
- Lean-fueled turbines with catalytic combustors compress the air/methane mixture and then combust it in a catalytic combustor
- Hybrid coal- and ventilation air-fueled gas turbine technology
- Lean-fueled catalytic microturbine technology
- Combustion air for commercial engine and turbine technologies or a coal-fired steam power plant

In some cases, VAM projects may need to supplement VAM with CMM from drainage boreholes, either to increase the concentration of methane flowing into the combustion/oxidation device or to help balance the concentration of methane flowing into the combustion/oxidation device. This supplemental CMM is also eligible as part of a VAM project, as long as the supplemental CMM would not have been used for energy purposes.

The Performance Standard Test is applied at the time a project applies for registration with the Reserve. Once a project is registered, it does not need to be evaluated against future versions of the protocol or the Performance Standard Test for the duration of its first crediting period.

If a project developer wishes to apply for a second crediting period, the project must meet the eligibility requirements of the most current version of this protocol, including any updates to the Performance Standard Test.

[10] A summary of the study and analysis used to establish the Performance Standard Test is provided in Appendix A.

3.5 Regulatory Compliance

As a final eligibility requirement, project developers must attest that the project is in material compliance with all applicable laws (e.g. air, water quality, safety, etc.) prior to verification activities commencing each time a project is verified. Project developers are required to disclose in writing to the verifier any and all instances of non-compliance of the project with any law. If a verifier finds that a project is in a state of recurrent non-compliance or non-compliance that is the result of negligence or intent, then CRTs will not be issued for GHG reductions that occurred during the period of non-compliance. Non-compliance solely due to administrative or reporting issues, or due to “acts of nature,” will not affect CRT crediting.

4 GHG Assessment Boundary

The GHG Assessment Boundary delineates the GHG sources, sinks and reservoirs (SSRs) that shall be assessed by project developers in order to determine the total net change in GHG emissions caused by a coal mine methane project.

This protocol does not account for carbon dioxide emission reductions associated with displacing grid-delivered electricity or fossil fuel use.

Figure 4.1 below provides a general illustration of the GHG Assessment Boundary, indicating which SSRs are included or excluded from the boundary.

Table 4.1 provides greater detail on each SSR and provides justification for all SSRs and gases that are excluded from the GHG Assessment Boundary. The GHG Assessment Boundary diagram and table presented here apply to both drainage and VAM projects; individual SSRs may or may not be relevant depending on the project type.

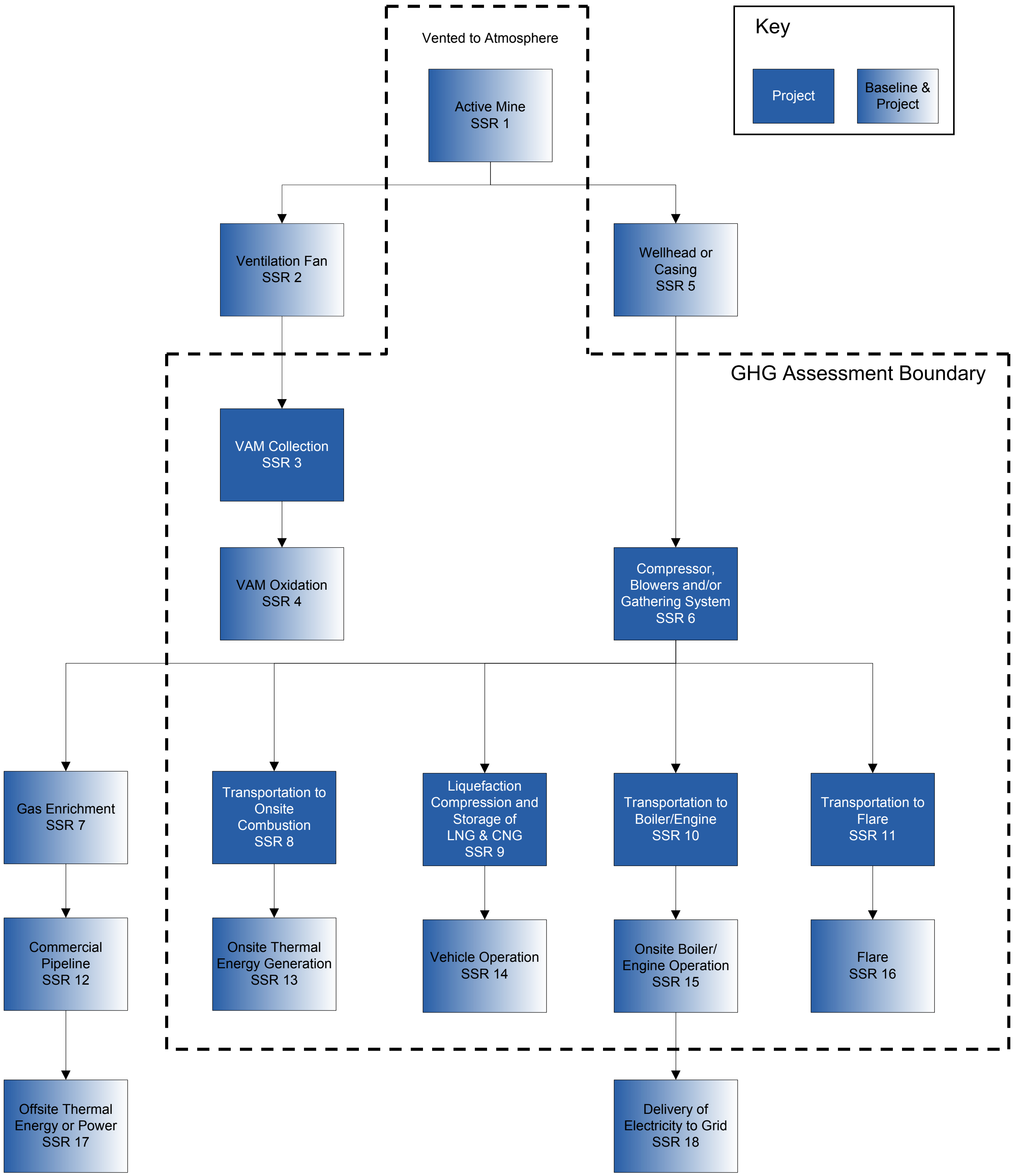


Figure 4.1. Illustration of the GHG Assessment Boundary

Table 4.1. Summary of Identified Sources, Sinks and Reservoirs

SSR	Source	Gas	Relevant to Baseline (B) or Project (P)	Included/ Excluded	Justification/Explanation
1	Active mine – emissions as a result of venting	CH_4	B, P	Included	Main emission source of methane from active mines. A GHG project will directly affect these emissions. Only the change in CMM emissions release will be taken into account, by monitoring the methane used or destroyed by the project.
2	Ventilation fan	CO_2	n/a	Excluded	Ventilation fan operation will not be affected by the project.
3	VAM collection system	CO_2	P	Included	The VAM collection system will result in increased combustion emissions due to energy consumption from equipment used to drain, compress, blow, and gather VAM.
		CH_4		Excluded	Excluded for simplification. This emission source is assumed to be very small.
		N_2O		Excluded	Excluded for simplification. This emission source is assumed to be very small.
4	VAM oxidation	CO_2	B, P	Included	VAM project will result in increased CO_2 emissions from the oxidation of methane in VAM.
		CH_4	P	Included	VAM project will result in increased CH_4 emissions from non-oxidized CH_4 from the VAM stream.
		N_2O	n/a	Excluded	Excluded for simplification. This emission source is assumed to be very small.
	Emissions from NMHC destruction	CO_2	P	Included if >0.1%	VAM project will result in increased CO_2 emissions from the combustion of NMHC in oxidizer (only included if NMHC accounts for more than 0.1% by volume of extracted VAM).
5	Fugitive emissions resulting from casing or wellhead	CH_4	n/a	Excluded	The project is unlikely to affect quantities of methane from this source.
6	Emissions resulting from energy used by compressors, blowers, and/or gathering system	CO_2	P	Included	If any additional equipment is required by the project beyond what is required in the baseline, energy consumption from additional equipment shall be accounted for. Energy used by equipment installed for the safety of the mine shall be excluded.
		CH_4		Excluded	Excluded for simplification. This emission source is assumed to be very small.
		N_2O		Excluded	Excluded for simplification. This emission source is assumed to be very small.
	Fugitive emissions resulting from compressors, blowers, and/or gathering system	CH_4	n/a	Excluded	Excluded for simplification. This emission source is assumed to be very small.
7	Emissions resulting from gas enrichment system	CO_2	n/a	Excluded	The project is unlikely to affect quantities of methane sent to gas enrichment systems, and will therefore not affect energy consumption or fugitive emissions from gas enrichment systems.
		CH_4		Excluded	
		N_2O		Excluded	
8	Fuel consumption for transport of the gas to on-site combustion	CO_2	P	Included	If any additional equipment is required by the project beyond what is required in the baseline, energy consumption from additional equipment shall be accounted for.
		CH_4		Excluded	Excluded for simplification. This emission source is assumed to be very small.
		N_2O		Excluded	Excluded for simplification. This emission source is assumed to be very small.
	Fugitive emissions from	CH_4	n/a	Excluded	Excluded for simplification. This emission source is

SSR	Source	Gas	Relevant to Baseline (B) or Project (P)	Included/ Excluded	Justification/Explanation
	transportation system to on-site combustion				assumed to be very small.
9	Emissions resulting from liquefaction, compression, or storage of methane for vehicle fuel	CO_2	P	Included	If any additional equipment is required by the project beyond what is required in the baseline, energy consumption from additional equipment shall be accounted for.
		CH_4		Excluded	Excluded for simplification. This emission source is assumed to be very small.
		N_2O		Excluded	Excluded for simplification. This emission source is assumed to be very small.
10	Fuel consumption for transport of the gas to boiler/engine	CO_2	P	Included	If any additional equipment is required by the project beyond what is required in the baseline, energy consumption from additional equipment shall be accounted for.
		CH_4		Excluded	Excluded for simplification. This emission source is assumed to be very small.
		N_2O		Excluded	Excluded for simplification. This emission source is assumed to be very small.
	Fugitive emissions from CMM transportation system to boiler/engine	CH_4	n/a	Excluded	Excluded for simplification. This emission source is assumed to be very small.
11	Fuel consumption for transport of the gas to flare	CO_2	P	Included	If any additional equipment is required in addition to what is required for baseline activity, energy consumption from equipment shall be accounted for.
		CH_4		Excluded	Excluded for simplification. This emission source is assumed to be very small.
		N_2O		Excluded	Excluded for simplification. This emission source is assumed to be very small.
	Fugitive emissions from CMM transportation system to flare	CH_4	n/a	Excluded	Excluded for simplification. This emission source is assumed to be very small.
12	Fugitive emissions from commercial pipelines	CH_4	n/a	Excluded	The project is unlikely to affect quantities of methane delivered to commercial pipelines, and will therefore not affect fugitive pipeline emissions.
13	Emissions resulting from combustion during on-site thermal energy generation	CO_2	B, P	Included	If CMM is used for on-site thermal energy generation, project will result in increased CO_2 emissions from the destruction of methane to generate energy. This source is also included where CMM is sent to a non-qualifying device to generate energy.
		N_2O		Excluded	Excluded for simplification. This emission source is assumed to be very small.
	Emissions resulting from incomplete combustion during onsite thermal energy generation	CH_4	P	Included	If CMM is used for on-site thermal energy generation, project will result in increased CH_4 emissions from incomplete combustion. This source is also included where CMM is sent to a non-qualifying device to generate energy.
	Emissions from NMHC destruction	CO_2	P	Included if >1%	If CMM is used for on-site thermal energy generation, project will result in increased CO_2 emissions from the combustion of NMHC during energy generation (only included if NMHC accounts for more than 1% by volume of CMM). This source is also included where CMM is sent to a non-qualifying device to generate energy.
14	Emissions resulting from combustion during vehicle operation	CO_2	B, P	Included	If CMM is used to produce CNG/LNG to fuel vehicle operation, project will result in increased CO_2 emissions from the destruction of methane in

SSR	Source	Gas	Relevant to Baseline (B) or Project (P)	Included/ Excluded	Justification/Explanation
					CNG/LNG vehicles. This source is also included where CMM is used for non-qualifying vehicle operation.
		N_2O		Excluded	Excluded for simplification. This emission source is assumed to be very small.
14 cont.	Emissions resulting from incomplete combustion during vehicle operation	CH_4	P	Included	If CMM is used to produce CNG/LNG to fuel vehicle operation, project will result in increased CH_4 emissions from incomplete combustion. This source is also included where CMM is used for non-qualifying vehicle operation.
	Emissions from NMHC destruction	CO_2	P	Included if >1%	If CMM is to produce CNG/LNG to fuel vehicle operation, project will result in increased CO_2 emissions from the combustion of NMHC during vehicle operation (only included if NMHC accounts for more than 1% by volume of CMM). This source is also included where CMM is used for non-qualifying vehicle operation.
15	Emissions resulting from combustion during on-site electricity generation	CO_2	B, P	Included	If CMM is used for on-site power generation, project will result in increased CO_2 emissions from the destruction of methane to generate power. This source is also included where CMM is sent to a non-qualifying device for electricity generation.
		N_2O		Excluded	Excluded for simplification. This emission source is assumed to be very small.
	Emissions resulting from incomplete combustion during on-site electricity generation	CH_4	P	Included	If CMM is used for on-site power generation, project will result in increased CH_4 emissions from incomplete combustion. This source is also included where CMM is sent to a non-qualifying device for electricity generation.
	Emissions from NMHC destruction	CO_2	P	Included if >1%	If CMM is used for on-site power generation, project will result in increased CO_2 emissions from the combustion of NMHC during power generation (only included if NMHC accounts for more than 1% by volume of CMM). This source is also included where CMM is sent to a non-qualifying device for electricity generation.
16	Emissions resulting from combustion during flaring	CO_2	B, P	Included	If CMM is sent to a flare, project will result in increased CO_2 emissions from the destruction of methane in flare. This source is also included where CMM is sent to a non-qualifying device for flaring.
		N_2O		Excluded	Excluded for simplification. This emission source is assumed to be very small.
	Emissions resulting from incomplete combustion during flaring	CH_4	P	Included	If CMM is sent to a flare, project will result in increased CH_4 emissions from incomplete combustion. This source is also included where CMM is sent to a non-qualifying device for flaring.
	Emissions from NMHC destruction	CO_2	P	Included if >1%	If CMM is sent to a flare, project will result in increased CO_2 emissions from the combustion of NMHC in flare (only included if NMHC accounts for more than 1% by volume of CMM).
17	Emissions resulting from offsite thermal or power generation	CO_2	n/a	Excluded	The project is unlikely to affect quantities of methane delivered through pipelines to offsite thermal or power generation equipment, and will therefore not affect emissions from such
		N_2O			
	Emissions resulting	CH_4			

SSR	Source	Gas	Relevant to Baseline (B) or Project (P)	Included/ Excluded	Justification/Explanation
	from incomplete combustion during off-site thermal energy or power generation				equipment.
18	Delivery of electricity to grid	CO_2 CH_4 N_2O	n/a	Excluded	This protocol does not cover displacement of GHG emissions from the use of CMM for grid-connected electricity generation.
	Project construction and decommissioning emissions	CO_2 CH_4 N_2O	n/a	Excluded	Excluded for simplification. This emission source is assumed to be very small.

5 Quantifying GHG Emission Reductions

GHG emission reductions from a coal mine methane project are quantified by comparing actual project emissions to baseline emissions at the mine. Baseline emissions are an estimate of the GHG emissions from sources within the GHG Assessment Boundary (see Section 4) that would have occurred in the absence of the coal mine methane project. Project emissions are actual GHG emissions that occur at sources within the GHG Assessment Boundary. Project emissions must be subtracted from the baseline emissions to quantify the project's total net GHG emission reductions (Equation 5.1).

GHG emission reductions must be quantified and verified on at least an annual basis. Project developers may choose to quantify and verify GHG emission reductions on a more frequent basis if they desire. The length of time over which GHG emission reductions are quantified and verified is called the "reporting period".

Equation 5.1. Calculating GHG Emission Reductions

$$ER = BE - PE$$

Where,			Units
ER	=	GHG emission reductions of the project activity during the reporting period	tCO_2e
BE	=	Baseline emissions during the reporting period	tCO_2e
PE	=	Project emissions during the reporting period	tCO_2e

The calculations provided in this protocol are derived from internationally accepted methodologies.[11] Project developers shall use the calculation methods provided in this protocol to determine baseline and project GHG emissions in order to quantify GHG emission reductions.

Note that throughout the protocol, it is assumed that measured quantities of coal mine gas are converted to metric tons of methane using the following three parameters:

- Measured methane concentration of the coal mine gas
- Volume of gas, corrected to standard conditions
- Density of methane at standard conditions

Equation 5.2 provides guidance for calculating the mass of methane from the independently measured parameters of gas volume and methane concentration.

[11] The Reserve's GHG reduction calculation method for CMM projects is derived from the UNFCCC approved consolidated methodology under the Kyoto Protocol's Clean Development Mechanism (ACM0008/Version 6), and also draws from Greenhouse Gas Services Methodology for Coal Mine Methane and Abandoned Mine Methane Capture and Destruction Projects (Version 1.1), the U.S. EPA Inventory of U.S. GHG Emissions and Sinks 1990-2007, and the 2006 IPCC Guidelines for National GHG Inventories.

Also note that Equation 5.2 distinguishes between *coal mine gas* (CMG), which is the gas that comes out of the boreholes before any processing or enrichment and often contains various levels of other compounds (e.g. nitrogen, oxygen, carbon dioxide, hydrogen sulfide, NMHC, etc.) and *coal mine methane*, which represents only the methane portion of CMG.

Equation 5.2. Converting Coal Mine Gas Volumes to Metric Tons of Coal Mine Methane

$$tCH_4 = (0.0423 \times 0.000454) \times \sum_t scfCMG_t \times \%CH_{4t}$$

Where,			Units
tCH_4	=	total quantity of CMM	tCH_4
t	=	Time interval for which flow and concentration measurements are aggregated (daily)	
$\%CH_{4t}$	=	The average methane fraction of the CMM in time interval t as measured	scf CH_4/scf
$scfCMG_t$	=	Total volume of coal mine gas in time interval t, as measured (see Equation 5.12 for additional guidance on adjusting the CMM flow for temperature and pressure)	scf CMG
0.0423	=	Density of methane	lb CH_4/scf CH_4
0.000454	=	tCH_4/lb CH_4	t/lb

5.1 Quantifying Baseline Emissions

Total baseline emissions must be estimated by calculating and summing the expected baseline emissions for all relevant SSRs (as indicated in Table 4.1) using Equation 5.3 and the supporting equations presented below.

Equation 5.3. Calculating Baseline Emissions

$$BE = BE_{MD} + BE_{MR}$$

Where,			Units
BE	=	Baseline emissions during the reporting period	tCO_2e
BE_{MD}	=	Baseline emissions from destruction of methane in the baseline scenario during the reporting period	tCO_2e
BE_{MR}	=	Baseline emissions from release of methane into the atmosphere that would have occurred in the absence of the project during the reporting period	tCO_2e

Baseline emissions from CMM release or destruction may be associated with four different stages of mining activity:

1. Surface pre-mining: boreholes are drilled from the surface to unmined portions of the coal seam in advance of mining. CMM drained from surface pre-mining boreholes is represented as SMM in the equations below.

2. Horizontal pre-mining: boreholes are drilled horizontally from within the mine into unmined blocks of coal shortly before mining occurs (also referred to as in-mine boreholes). CMM drained from horizontal pre-mining boreholes is represented as HMM in the equations below.

3. Ventilation during mining through required ventilation systems. CMM collected from ventilation systems is represented as VAM in the equations below.

4. Post-mining: boreholes are drilled from the surface to a point 10 to 50 feet above the coal seam in advance of mining. As mining advances under and past the well, the strata above the coal seam collapses into the mined out area creating a de-pressurized zone extending up to the well; this zone is called the gob. CMM drained from post-mining boreholes is represented as PMM in the equations below.

5.1.1 Calculating Baseline Carbon Dioxide Emissions from Methane Destruction

Depending on the mine, some CMM may be destroyed in the baseline through flaring, oxidation, power generation, heat generation, etc., in non-qualifying destruction devices (See Section 2.2.3). Baseline emissions estimates must include the estimated CO_2 emissions from the destruction of CMM in non-qualifying devices, calculated using Equation 5.4.

The amount of CMM destroyed in the baseline by a non-qualifying destruction device (variables $SMM_{BL,i}$, $HMM_{BL,i}$, $PMM_{BL,i}$ and $VAM_{BL,i}$ in Equation 5.4) is established by calculating and comparing:

1. The actual amount of SMM, HMM, PMM and VAM destroyed by the non-qualifying destruction device during the reporting period; and
2. The amount of SMM, HMM, PMM and VAM destroyed by the non-qualifying destruction device over the 3 year period prior to the implementation of the project (or however long the non-qualifying destruction device has been operational, whichever is shorter), averaged according to the length of the reporting period. For example, if the reporting period is three months, then the 3-year historical amount must be divided by 12 to derive the average amount of destruction in a three-month period.

The higher of either (1) or (2) must be used for $SMM_{BL,i}$, $HMM_{BL,i}$, $PMM_{BL,i}$ and $VAM_{BL,i}$ in Equation 5.4 (and Equation 5.5 in the next section).

If a non-qualifying destruction device in operation at the mine that was shut down less than one year prior to the project start date – or if a non-qualifying device is shut down at any point during the project's crediting period – the project developer must still account for the device in the baseline calculations, using the historical destruction amount calculated in (2), above. If the device was shut down more than one year before the project start date, it does not need to be accounted for in the baseline calculations.

If there is no destruction of methane in the baseline, then $BE_{MD} = 0$.

Note: At some mines, the baseline may involve sending some CMM to a natural gas pipeline for off-site consumption/destruction. The pipeline could therefore be considered a "non-qualifying device." However, because on-site CMM destruction projects are unlikely to affect the quantity of CMM delivered to pipelines (due to the likely physical and temporal separation of these activities), emissions associated with pipelines are excluded from the GHG Assessment Boundary, and do not need to be accounted for in the baseline or project case.

Equation 5.4. Calculating Baseline CO_2 Emissions from CH_4 Destruction by Non-Qualifying Devices

$$BE_{MD} = \left(CEF_{CH_4} + r \times CEF_{NMHC}\right) \times \sum_i \left(SMM_{BL,i} + VAM_{BL,i} + HMM_{BL,i} + PMM_{BL,i}\right)$$

Where,			Units
BE_{MD}	=	Baseline emissions from destruction of methane in the baseline scenario in the reporting period	tCO_2e
i	=	Use of methane (flaring, power generation, heat generation, etc.). Uses must include all non-qualifying devices.	
$SMM_{BL,i}$	=	CMM from surface pre-mining that would have been captured, sent to and destroyed by use i in the baseline scenario in the reporting period	tCH_4
$VAM_{BL,i}$	=	VAM that would have been captured, sent to and destroyed by use i in the baseline scenario in the reporting period	tCH_4
$HMM_{BL,i}$	=	CMM from horizontal pre-mining that would have been captured, sent to and destroyed by use i in the baseline scenario in the reporting period	tCH_4
$PMM_{BL,i}$	=	Post-mining CMM that would have been captured, sent to and destroyed by use i in the baseline scenario in the reporting period	tCH_4
CEF_{CH4}	=	CO_2 emission factor for combusted methane (2.75)[12]	tCO_2e/tCH_4
CEF_{NMHC}	=	CO_2 emission factor for combusted non methane hydrocarbons	$tCO_2e/tNMHC$
r	=	Relative proportion of NMHC compared to methane	

with:

$$r = PC_{NMHC} / PC_{CH_4}$$

Where,			Units
r	=	Relative proportion of NMHC compared to methane	
PC_{NMHC}	=	NMHC concentration (in mass) in extracted gas	%
PC_{CH4}	=	Concentration (in mass) of methane in extracted gas, measured on wet basis	%

[12] Use the molar mass of CO_2 and CH_4 to calculate tCO_2e/tCH_4 (44/16 = 2.75).

5.1.2 Calculating Baseline Methane Emissions

Baseline emissions must include the methane that would have been emitted to the atmosphere in the absence of the project activity. Baseline emissions of methane are calculated by summing the total amount of methane *actually destroyed* by all qualifying and non-qualifying devices during the reporting period, and subtracting the amount that would have been destroyed in the baseline, as determined in Section 5.1.1. The difference between the actual amount of methane destroyed and what would have been destroyed determines how much methane would have been released. Baseline methane emissions must be calculated using Equation 5.5.

In Equation 5.5, actual methane destruction at all qualifying devices (those installed as part of the project to destroy methane) and non-qualifying devices must be accounted for. For qualifying devices, baseline values for methane destruction (i.e. $SMM_{BL,i}$, $HMM_{BL,i}$, $PMM_{BL,i}$ and $VAM_{BL,i}$) will be zero.

Baseline methane emissions from surface pre-mining (SMM) are quantified only during reporting periods in which the emissions *would have occurred* (i.e. when the borehole is mined through). Thus, baseline methane emissions from SMM must be determined according to the amount of *eligible* CMM that has been destroyed, as defined in Section 5.1.2.1.

If a qualifying device for a VAM project uses CMM to supplement the flow of VAM, the supplemental CMM must be accounted for in Equation 5.5 according to its source (SMM, HMM, or PMM) if VAM flow and supplemental CMM flow are monitored separately, or directly through $VAM_{PJ,i}$ if only the resulting enriched flow is monitored.

Any methane that is still vented in the project scenario is not accounted for in the project emissions or baseline emissions, since it is vented in both scenarios. Similarly, the methane that is injected into natural gas pipeline in the project scenario is not accounted for in the project emissions or baseline emissions, since it is injected in both scenarios.

Equation 5.5. Calculating Baseline Methane Released to the Atmosphere

$$BE_{MR} = GWP_{CH_4} \times \left[\begin{array}{l} \sum_i \left(SMMe_i - SMM_{BL,i}\right) + \sum_i \left(HMM_{PJ,i} - HMM_{BL,i}\right) \\ + \sum_i \left(PMM_{PJ,i} - PMM_{BL,i}\right) + \sum_i \left(VAM_{PJ,i} - VAM_{BL,i}\right) \end{array} \right]$$

Where,			Units
BE_{MR}	=	Baseline methane emissions avoided by the project activity in the reporting period	tCO_2e
i	=	Use of methane (flaring, power generation, heat generation, etc.). *Uses must include all qualifying and non-qualifying devices*	
$SMMe_i$	=	*Actual* amount of CMM from surface pre-mining captured, sent to and destroyed by use i for the reporting period. For qualifying devices, only the *eligible* amount shall be quantified (see Section 5.1.2.1)	tCH_4
$SMM_{BL,i}$	=	CMM from surface pre-mining that would have been captured, sent to and destroyed by use i in the baseline scenario in the reporting period, as determined in Section 5.1.1	tCH_4
$HMM_{PJ,i}$	=	*Actual* amount of CMM from horizontal pre-mining captured, sent to and destroyed by use i in the reporting period	tCH_4
$HMM_{BL,i}$	=	CMM from horizontal pre-mining that would have been captured, sent to and destroyed by use i in the baseline scenario in the reporting period, as determined in Section 5.1.1	tCH_4
$PMM_{PJ,i}$	=	*Actual* amount of post-mining CMM captured, sent to and destroyed by use i in the project activity in the reporting period	tCH_4
$PMM_{BL,i}$	=	Post-mining CMM that would have been captured, sent to and destroyed by use I in the baseline scenario in the reporting period, as determined in Section 5.1.1	tCH_4
$VAM_{PJ,i}$	=	*Actual* amount of VAM sent to and destroyed by use i in the project activity in the reporting period. In the case of oxidation, $VAM_{PJ,i}$ is equivalent to MM_{OX} defined in Section 5.2.2	tCH_4
$VAM_{BL,i}$	=	VAM that would have been captured, sent to and destroyed by use i in the baseline scenario in the reporting period, as determined in Section 5.1.1	tCH_4
GWP_{CH4}	=	Global warming potential of methane (21)	tCO_2e/tCH_4

5.1.2.1 Determining Eligible SMM

To determine the amount of baseline SMM that is eligible to be quantified in a given reporting period, project developers shall identify what boreholes within the bounds of active coal extraction were "mined through" during the reporting period. The most current mine plan shall be used to identify these boreholes.

Baseline SMM emissions are quantified only when the endpoint of the borehole is mined through. If the mine plan calls for mining past rather than through the borehole, then quantification is allowed once the linear distance between the endpoint of the borehole and the working face that will pass nearest the endpoint of the borehole has reached an absolute minimum.

For the purposes of this protocol, mined through is defined as any of the following:

- The working face intersects the endpoint of the borehole
- The working face passes directly underneath the bottom of the borehole, as long as the endpoint of the borehole is within a -50 meter to +150 meter vertical range of the mined coal seam
- The working face intersects the plane of the borehole
- The working face passes both underneath and to the side of the borehole (which will happen when the bottom of the borehole lies above a block of coal that will be left unmined as a pillar)

Once a borehole is mined through, SMM from that borehole that was captured and destroyed by a qualifying device in previous reporting periods may be reported and quantified for the current reporting period (as a component of $SMMe_i$ in Equation 5.5). $SMMe_i$ is calculated as the sum of SMM captured and destroyed by qualifying devices from wells mined through in the current reporting period ($SMMpre_e$), plus SMM captured and destroyed by qualifying devices from wells that were mined through in previous reporting periods ($SMMpost_e$) – see Equation 5.6.

Equation 5.6. Calculating Eligible CMM from Surface Pre-mining Boreholes

$$SMMe_i = SMMpre_e + SMMpost_e$$

Where,			Units
$SMMe_i$	=	Actual amount of CMM from surface pre-mining captured, sent to and destroyed by use i that is *eligible* for quantification in the reporting period	tCH_4
$SMMpre_e$	=	Actual amount of CMM destroyed by qualifying devices in the current reporting period from surface pre-mining boreholes that were mined through during the current reporting period	tCH_4
$SMMpost_e$	=	Actual amount of CMM destroyed by qualifying devices in the current reporting period from surface pre-mining boreholes that were previously mined through	tCH_4

and:

$$SMMpre_e = \sum_{w_1} \left(SMM_{w_1} \right)$$

Where,			Units
$SMMw_1$	=	Total actual amount of CMM captured and destroyed from well w_1 from the project start date through the end of the current reporting period	tCH_4
w_1	=	The set of wells mined through in current reporting period	

and:

$$SMMpost_e = \sum_{w_2} \left(SMM_{w_2} \right)$$

Where,			Units
$SMMw_2$	=	Actual amount of CMM captured and destroyed from well w_2 during the current reporting period	tCH_4
w_2	=	The set of wells mined through prior to the current reporting period	

For example, at a mine in which 5 surface pre-mining wells had been drilled and whose reporting period is 12 months long, if all five wells are mined through in year 4, then in years 1 to 3 the eligible CMM from surface pre-mining would be zero. In year 4 it would be the cumulative volume for the previous 3 years plus the volume extracted in year 4. In year 5 it would only be the volume extracted in year 5.

5.2 Quantifying Project Emissions

Project emissions must be quantified at a minimum on an annual, *ex-post* basis. As shown in Equation 5.7, project emissions equal:

- CO_2 emissions from energy used to destroy CMM/VAM plus
- CO_2 emissions from CMM/VAM destroyed in qualifying and non-qualifying destruction devices plus
- Uncombusted CH_4 emissions from qualifying and non-qualifying destruction devices

Equation 5.7. Project Emissions

$$PE = PE_{ME} + PE_{MD} + PE_{UM}$$

Where,			Units
PE	=	Project emissions	tCO_2e
PE_{ME}	=	Project emissions from energy required for methane collection, transport, and combustion	tCO_2e
PE_{MD}	=	Project emissions from methane destroyed	tCO_2e
PE_{UM}	=	Project emissions from uncombusted methane	tCO_2e

5.2.1 Project Emissions from Energy Required for Methane Collection, Transport, and Combustion

Included in the GHG Assessment Boundary are carbon dioxide emissions resulting from fossil fuel combustion and/or use of grid-delivered electricity for on-site equipment that is used for:

- VAM collection
- Compressors, blowers and/or CMM gathering systems
- Transporting CMM to on-site combustion
- Liquefaction, compression and storage of liquid natural gas (LNG) or compressed natural gas (CNG) created from CMM
- Transporting CMM to boilers/engines for power generation
- Transporting CMM to a flare

If the project utilizes fossil fuel or grid electricity to power equipment necessary for performing the above processes, the resulting project carbon dioxide emissions shall be calculated per Equation 5.8 below. Note that fossil fuel or grid electricity to power equipment installed for the safety of the mine shall be excluded, as that equipment is not within the GHG Assessment Boundary of the project.

Equation 5.8. CO_2 Emissions from Fossil Fuel and Grid Electricity

$$PE_{ME} = \left(CONS_{ELEC,PJ} \times CEF_{ELEC} \right) + \frac{\left(CONS_{HEAT,PJ} \times CEF_{HEAT} + CONS_{FossFuel,PJ} \times CEF_{FossFuel} \right)}{1000}$$

Where,			Units
PE_{ME}	=	Project emissions from energy required for methane collection, transport, and combustion	tCO_2e
$CONS_{ELEC,PJ}$*	=	Additional electricity consumption for destruction of methane, if any	MWh
CEF_{ELEC}	=	CO_2 emission factor of electricity used by coal mine; see Appendix B for emission factors by eGRID subregion	tCO_2/MWh
$CONS_{HEAT,PJ}$	=	Additional heat consumption for destruction of methane, if any	volume
CEF_{HEAT}	=	CO_2 emissions factor of heat used by coal mine; see Appendix B for guidance on deriving emission factor	kg CO_2/volume
$CONS_{FossFuel,PJ}$	=	Additional fossil fuel consumption for destruction of methane, if any	volume
$CEF_{FossFuel}$	=	CO_2 emission factor of fossil fuel used by coal mine; see Appendix B for emission factors by fuel type	kg CO_2/volume
1/1000	=	Conversion of kg to metric tons	

* If total electricity being generated by project activities is $\geq$ the additional electricity consumption, then $CONS_{ELEC,PJ}$ shall not be accounted for in the project emissions and shall be omitted from the equation above.

5.2.2 Project Emissions from Destruction of Captured Methane

When CMM/VAM is burned in a flare, heat or power plant, or oxidized in an oxidation unit, carbon dioxide emissions are released and must be accounted for. In addition, if non-methane hydrocarbons (NMHC) comprise more than 1% of the volume of extracted CMM or more than 0.1% of the volume of extracted VAM, carbon dioxide emissions from combustion of NMHC must also be accounted for.

Equation 5.9 must be used to calculate carbon dioxide emissions from destruction of captured methane at qualifying and non-qualifying devices.

Note: Although baseline methane emissions from surface pre-mining are accounted for only when they are eligible (i.e. after the borehole is mined through), CO_2 emissions resulting from the destruction of surface pre-mining CMM must be accounted for in the period during which the destruction occurs, using Equation 5.9.

Equation 5.9. CO_2 Emissions from Destruction of Captured CH_4

$$PE_{MD} = \left(MD_{OX} + MD_i\right) \times \left(CEF_{CH_4} + r \times CEF_{NMHC}\right)$$

with:

$$r = {PC_{NMHC}} \Big/ {PC_{CH_4}}$$

Where,			Units
PE_{MD}	=	Project emissions from methane destroyed during the current reporting period	tCO_2e
MD_i[13]	=	Methane destroyed by all qualifying and non-qualifying devices	tCH_4
MD_{OX}	=	Methane destroyed through oxidation	tCH_4
CEF_{CH4}	=	CO_2 emission factor for combusted methane (2.75)	tCO_2/tCH_4
CEF_{NMHC}	=	CO_2 emission factor for combusted NMHC[14]	$tCO_2/tNMHC$
r	=	Relative proportion of NMHC compared to methane	
PC_{NMHC}	=	NMHC concentration (in mass) in extracted gas	%
PC_{CH4}	=	Concentration (in mass) of methane in extracted gas, measured on wet basis	%

For each end-use destruction device (qualifying and non-qualifying), the amount of gas destroyed depends on the efficiency of combustion for that destruction device. For VAM project destruction devices, Equation 5.10 must be used to quantify the methane destroyed by oxidation, which accounts for the destruction efficiency of the oxidation unit on a continuous basis. For drainage project destruction devices, Equation 5.11 must be used to quantify the methane destroyed for each qualifying and non-qualifying device.

Using Equation 5.11, project developers have the option to use either the default methane destruction efficiencies provided in Appendix B, or site-specific methane destruction efficiencies. Site specific destruction efficiencies for each qualifying or non-qualifying device must be determined by a source-test service provider accredited by a state or local agency. If the project developer chooses to use site-specific destruction efficiencies, the destruction device shall be source tested at least annually and the destruction efficiency updated accordingly.

[13] MD_i includes methane from all SMM sent to qualifying devices, not just eligible SMM.

[14] Because concentrations of different NMHC components may vary over time, the appropriate emission factor shall be obtained through annual analysis of captured gas from each drainage system type.

Equation 5.10. CH_4 Destroyed by VAM Oxidation

$$MD_{OX} = MM_{OX} - PE_{OX}$$

Where,			Units
MD_{OX}	=	Methane destroyed through oxidation	tCH_4
MM_{OX}	=	Methane measured sent to oxidizer	tCH_4
PE_{OX}	=	Project emissions of non-oxidized CH_4 from oxidation of the VAM stream	tCH_4

and:

$$MM_{OX} = VAM_{flow.rate,y} \times time_y \times PC_{CH_4.VAM} \times D_{CH_4,corr.inflow}$$

Where,			Units
$VAM_{flow.rate,y}$	=	Average flow rate of methane entering the oxidation unit during period y	scfm
$time_y$	=	Time during which VAM unit is operational during period y	m
$PC_{CH4.VAM}$	=	Concentration of methane in the air entering the oxidation unit	scf/scf
$D_{CH4,corr.inflow}$	=	Density of methane entering the oxidation unit corrected for pressure and temperature ($P_{VAMinflow}$ and $T_{VAMinflow}$ respectively)	tCH_4/scf

and:

$$PE_{OX} = VAM_{flow.rate,y} \times time_y \times PC_{CH_4.exhaust} \times D_{CH_4,corr.exh}$$

Where,			Units
$PC_{CH4.exhaust}$	=	Concentration of methane in the VAM exhaust	scf/scf
$D_{CH4,corr.exh}$	=	Density of methane corrected for pressure and temperature in the exhaust gases ($P_{VAMexhaust}$ and $T_{VAMexhaust}$ respectively)	tCH_4/scf

Equation 5.11. CH_4 Destroyed by Other (Non-VAM) Destruction Devices

$$MD_i = \sum_i MM_i \times Eff_i$$

Where,			Units
MD_i	=	Methane destroyed by all qualifying and non-qualifying devices i	tCH_4
MM_i	=	Methane measured sent to use i	tCH_4
Eff_i	=	Efficiency of methane destruction device i; see Appendix B for default destruction efficiencies by destruction device[15]	%

Equation 5.12. Adjusting CMM Flow for Temperature and Pressure

Important: Apply the following equation only if the CMM/VAM flow metering equipment does not internally correct for temperature and pressure.

$$MM_{adjusted,i} = MM_{unadjusted,i} \times \frac{520}{T} \times \frac{P}{1}$$

Where,			Units
$MM_{adjusted,i}$	=	adjusted volume of CMM collected for the given time interval at utilization type i, adjusted to 60° F and 1 atm	scf/unit time
$MM_{unadjusted,i}$	=	unadjusted volume of CMM collected for the given time interval at utilization type i	scf/unit time
T	=	measured temperature of the CMM for the given time period (°R = °F + 460)	°R
P	=	measured pressure of the CMM for the given time interval	Atm

[15] Project developers have the option to use either the default methane destruction efficiencies provided, or site specific methane destruction efficiencies as provided by a state or local agency accredited source test service provider, for each of the combustion devices used in the project.

5.2.3 Emissions from Uncombusted Methane

Not all of the methane sent to the flare, to the oxidizer or used to generate heat and power will be combusted; a small amount will escape to the atmosphere. These emissions are calculated using Equation 5.13.

As in Equation 5.11, project developers again have the option to use either the default methane destruction efficiencies provided in Appendix B, or site specific methane destruction efficiencies in Equation 5.13. If the project developer chooses to use site specific destruction efficiencies in Equation 5.11, they must use the same destruction efficiencies in Equation 5.13.

Equation 5.13. Uncombusted CH_4 Emissions

$$PE_{UM} = \left[GWP_{CH_4} \times \sum_i MM_i \times \left(1 - Eff_i\right) \right] + PE_{OX} \times GWP_{CH_4}$$

Where,			Units
PE_{UM}	=	Project emissions from uncombusted methane	tCO_2e
GWP_{CH4}	=	Global warming potential of methane (21)	tCO_2e/tCH_4
i	=	The set of all qualifying and non-qualifying devices	
MM_i	=	Methane measured sent to use i	tCH_4
Eff_i	=	Efficiency of methane destruction in use i; see Appendix B for default destruction efficiencies by destruction device[16]	%
PE_{OX}	=	Project emissions of non oxidized methane from oxidation of the VAM stream	tCH_4

[16] Project developers have the option to use either the default methane destruction efficiencies provided, or site specific methane destruction efficiencies as provided by a state or local agency accredited source test service provider, for each of the combustion devices used in the project.

6 Project Monitoring

The Reserve requires a Monitoring Plan to be established for all monitoring and reporting activities associated with the project. The Monitoring Plan will serve as the basis for verification bodies to confirm that the monitoring and reporting requirements in this section and Section 7 have been and will continue to be met, and that consistent, rigorous monitoring and record-keeping is ongoing at the project site. The Monitoring Plan must cover all aspects of monitoring and reporting contained in this protocol and must specify how data for all relevant parameters in Table 6.1 (below) will be collected and recorded.

At a minimum the Monitoring Plan shall stipulate the frequency of data acquisition; a record keeping plan (see Section 7.3 for minimum record keeping requirements); the frequency of instrument field check and calibration activities; and the role of individuals performing each specific monitoring activity. The Monitoring Plan should include QA/QC provisions to ensure that data acquisition and meter calibration are carried out consistently and with precision.

Finally, the Monitoring Plan must include procedures that the project developer will follow to ascertain and demonstrate that the project at all times passes the Legal Requirement Test (Section 3.4.1).

Project developers are responsible for monitoring the performance of the project and ensuring that the operation of CMM destruction devices is consistent with the manufacturer's recommendations for each piece of equipment.

6.1 Monitoring Requirements

For drainage projects, the drainage systems and methane destruction devices must be monitored with measurement equipment that directly meters:

- The total flow of CMM from each drainage system defined as part of a project, measured continuously and recorded every 15 minutes or totalized and recorded at least daily, adjusted for temperature and pressure, prior to delivery to each destruction device

- The flow of CMM delivered to each destruction device, measured continuously and recorded every 15 minutes or totalized and recorded at least daily, adjusted for temperature and pressure

- The fraction of methane in the CMM delivered to each destruction device, measured continuously and recorded every 15 minutes and averaged at least daily

For VAM projects, monitoring requirements include:

- The total inlet flow entering the reaction chamber, measured continuously and recorded every two minutes to calculate average flow per hour

- Temperature and pressure of the inlet flow and the exhaust gas from the oxidation unit, measured continuously and recorded every hour to calculate hourly pressure and temperature

- The fraction of methane in the VAM entering oxidation unit and in the exhaust gas, measured continuously and recorded every two minutes to calculate average methane concentration per hour

All flow data collected must be corrected for temperature and pressure at 60° F and 1 atm. Equation 5.12 must be applied if flow metering equipment does not make this correction automatically.

For both VAM projects and drainage projects, NMHC content of the CMG shall be determined by a full gas analysis by an ISO 17025 accredited lab using a gas chromatograph on an annual basis. Separate gas samples shall be collected prior to each destruction device within the project definition.

Operational activity of the CMM drainage systems and the destruction devices shall be monitored and documented at least hourly to ensure actual methane destruction. GHG reductions will not be accounted for during periods in which the destruction device is not operational.

6.2 Instrument QA/QC

Monitoring instruments shall be inspected, cleaned, and calibrated according to the following schedule.

All gas flow meters[17] and continuous methane analyzers must be:

- Cleaned and inspected on a quarterly basis, with the activities performed and as found/as left condition of the equipment documented

- Field checked for calibration accuracy with the percent drift documented, using either a portable instrument (such as a pitot tube) or manufacturer specified guidance, at the end of - but no more than two months prior to - the end date of the reporting period[18]

- Calibrated by the manufacturer or a certified calibration service per manufacturer's guidance or every 5 years, whichever is more frequent

If the field check on a piece of equipment reveals accuracy outside of a +/- 5% threshold, calibration by the manufacturer or a certified service provider is required for that piece of equipment.

For the interval between the last successful field check and any calibration event confirming accuracy below the +/- 5% threshold, all data from that meter or analyzer must be scaled according to the following procedure. These adjustments must be made for the entire period from the last successful field check until such time as the meter is properly calibrated.

1. For calibrations that indicate under-reporting (lower flow rates, or lower methane concentration), the metered values must be used without correction.

[17] Field checks and calibrations of flow meters shall assess the volumetric output of the flow meter.
[18] Instead of performing field checks, the project developer may instead have equipment calibrated by the manufacturer or a certified calibration service per manufacturer's guidance, at the end of but no more than two months prior to the end date of the reporting period to meet this requirement.

2. For calibrations that indicate over-reporting (higher flow rates, or higher methane concentration), the metered values must be adjusted based on the greatest calibration drift recorded at the time of calibration.

For example, if a project conducts field checks quarterly during a year-long reporting period, then only three months of data will be subject at any one time to the penalties above. However, if the project developer feels confident that the meter does not require field checks or calibration on a greater than annual basis, then failed events will accordingly require the penalty to be applied to the entire year's data. Further, frequent calibration may minimize the total accrued drift (by zeroing out any error identified), and result in smaller overall deductions.

In order to provide flexibility in verification, data monitored up to two months after a field check may be verified. As such, the end date of the reporting period must be no more than two months after the latest successful field check.

If a portable calibration instrument is used for field checks (such as a pitot tube), the portable instrument shall be calibrated at least annually by the manufacturer or at an ISO 17025 accredited laboratory.

6.3 Missing Data

In situations where the flow rate or methane concentration monitoring equipment is missing data, the project developer shall apply the data substitution methodology provided in Appendix C. If for any reason the destruction device monitoring equipment is inoperable (for example, the thermal coupler on the flare), then no emission reductions can be credited for the period of inoperability.

6.4 Monitoring Parameters

Prescribed monitoring parameters necessary to calculate baseline and project emissions are provided in Table 6.1.

Table 6.1. Coal Mine Methane Project Monitoring Parameters

Eq. #	Parameter	Description	Data Unit	Measurement Frequency	Calculated (c) Measured (m) Reference (r) Operating records (o)	Comment
5.4 5.5	$SMM_{BL,i}$	CMM from surface pre-mining that would have been captured, sent to and destroyed by use i in the baseline scenario in the reporting period	tCH_4	Estimated at start of project and calculated annually, if non-qualifying destruction device is still in place	c, m	The higher of the two calculated values is used
5.4 5.5	$HMM_{BL,i}$	CMM from horizontal pre-mining that would have been captured, sent to and destroyed by use i in the baseline scenario in the reporting period	tCH_4	Estimated at start of project and calculated annually, if non-qualifying destruction device is still in place	c, m	The higher of the two calculated values is used

Eq. #	Parameter	Description	Data Unit	Measurement Frequency	Calculated (c) Measured (m) Reference (r) Operating records (o)	Comment
5.4 5.5	$PMM_{BL,i}$	Post-mining CMM that would have been captured, sent to and destroyed by use i in the baseline scenario in the reporting period	tCH_4	Estimated at start of project and calculated annually, if non-qualifying destruction device is still in place	c, m	The higher of the two calculated values is used
5.4 5.5	$VAM_{BL,i}$	VAM that would have been captured, sent to and destroyed by use i in the baseline scenario in the reporting period	tCH_4	Estimated at start of project and calculated annually, if non-qualifying destruction device is still in place	c, m	The higher of the two calculated values is used
5.4 5.9	CEF_{CH4}	CO_2 emission factor for combusted methane	tCO_2e/tCH_4	n/a	r	44/16 = 2.75
5.4 5.9	CEF_{NMHC}	CO_2 emission factor for combusted non methane hydrocarbons (various)	$tCO_2e/tNMHC$	Annually	m	To be obtained through analysis of the fractional composition of captured gas
5.4 5.9	PC_{CH4}	Concentration (in mass) of methane in extracted gas (%), measured on wet basis	%	Continuous	m	To be measured on wet basis
5.4 5.9	PC_{NMHC}	NMHC concentration (in mass) in extracted gas	%	Annually	m	Based on full gas analysis by a certified gas lab using a gas chromatograph
5.5 5.6	$SMMe_i$	CMM from surface pre-mining captured, sent to and destroyed by use i for the reporting period. For qualifying devices, only the *eligible* amount may be quantified	tCH_4	Every reporting period	c, m	Only includes SMM from boreholes that have been "mined through" and SMM destroyed by non-qualifying devices (excluding SMM sent to pipeline)
5.5	$HMM_{PJ,i}$	CMM from horizontal pre-mining captured, sent to and destroyed by use i in the reporting period	tCH_4	Continuous	m	Includes metered HMM destroyed by both eligible and non-qualifying devices
5.5	$VAM_{PJ,i}$	VAM sent to and destroyed by use i in the project activity in the reporting period. In the case of oxidation, $VAM_{PJ,i}$ is equivalent to MM_{OX} defined in Section 5.2.2	tCH_4	Continuous	m	Includes metered VAM destroyed by both eligible and non-qualifying devices
5.5	$PMM_{PJ,i}$	CMM from post-mining captured, sent to and destroyed by use i in the project activity in the reporting period	tCH_4	Continuous	m	Includes metered PMM destroyed by both eligible and non-qualifying devices
5.5 5.13	GWP_{CH4}	Global warming potential of methane	tCO_2e/tCH_4		r	21

Eq. #	Parameter	Description	Data Unit	Measurement Frequency	Calculated (c) Measured (m) Reference (r) Operating records (o)	Comment
5.6	$SMMpre_e$	CMM destroyed by qualifying devices in the current reporting period from surface pre-mining boreholes that were mined through during the current reporting period	tCH_4	Every reporting period	m	
5.6	$SMMpost_e$	CMM destroyed by qualifying devices in the current reporting period from surface pre-mining boreholes that were previously mined through	tCH_4	Every reporting period	m	
5.6	$SMMw_1$	CMM captured and destroyed from well w_1 from the project start date through the end of the current reporting period	tCH_4	Every reporting period	m	
5.6	w_1	The set of wells mined through in current reporting period		Every reporting period	o	
5.6	$SMMw_2$	CMM captured from well w_2 during the current reporting period	tCH_4	Every reporting period	m	
5.6	w_2	The set of wells mined through prior to the current reporting period		Every reporting period	o	
5.8	$CONS_{ELEC,PJ}$	Additional electricity consumption for destruction of methane, if any	MWh	Every reporting period	o	From electricity use records
5.8	$CONS_{HEAT,PJ}$	Additional heat consumption destruction of methane	volume	Every reporting period	o	From purchased heat records
5.8	$CONS_{FossFuel,PJ}$	Additional fossil fuel consumption for destruction of methane	volume	Every reporting period	o	From fuel use records
5.8	CEF_{ELEC}	CO_2 emissions factor of electricity used by coal mine	tCO_2/ MWh	Every reporting period	r	See Appendix B
5.8	CEF_{HEAT}	CO_2 emissions factor of heat used by coal mine	kg CO_2/ volume	Every reporting period	c	See Appendix B
5.8	$CEF_{FossFuel}$	CO_2 emissions factor of fossil fuel used by coal mine	kg CO_2/ volume	Every reporting period	r	See Appendix B
5.9	MD_i	Methane destroyed by all qualifying and non-qualifying devices	tCH_4	Every reporting period	c	
5.10	$VAM_{flow.rate,y}$	Average flow rate of methane entering the oxidation unit during period y	scfm	Continuous	m, c	Readings taken every two minutes to calculate average hourly flow
5.10	$time_y$	Time during which VAM unit is operational during period y	m	Continuous		Readings taken every two minutes to calculate average hourly flow

Eq. #	Parameter	Description	Data Unit	Measurement Frequency	Calculated (c) Measured (m) Reference (r) Operating records (o)	Comment
5.10	$D_{CH4,corr.inflow}$	Density of methane entering the oxidation unit corrected for pressure and temperature ($P_{VAMinflow}$ and $T_{VAMinflow}$ respectively)	tCH_4/scf		r	Density of methane at 60ºF and 1 atm = 0.0423 lb./scf
5.10	$D_{CH4,corr.exh}$	Density of methane corrected for pressure and temperature in the exhaust gases ($P_{VAMexhaust}$ and $T_{VAMexhaust}$ respectively)	tCH_4/scf		r	Density of methane at 60ºF and 1 atm = 0.0423 lb./scf
5.10	$P_{VAMinflow}$	Pressure of VAM entering the oxidation unit	Atm	Continuous	m	Readings taken every hour to calculate hourly pressure
5.10	$T_{VAMinflow}$	Temperature of VAM entering the oxidation unit (º R = º F + 460)	º R	Continuous	m	Readings taken every hour to calculate hourly temperature
5.10	$P_{VAMexhaust}$	Pressure of exhaust gases exiting the oxidation unit	Atm	Continuous	m	Readings taken every hour to calculate hourly pressure
5.10	$T_{VAMexhaust}$	Temperature of exhaust gases exiting the oxidation unit (º R = º F + 460)	º R	Continuous	m	Readings taken every hour to calculate hourly temperature
5.10	$PC_{CH4,VAM}$	Concentration of methane in the air entering the oxidation unit	scf/scf	Continuous	m	Readings taken at least every two minutes and used to calculate average methane concentration per hour
5.10	$PC_{CH4,exhaust}$	Concentration of methane in the VAM exhaust	scf/scf	Continuous	m	Readings taken at least every two minutes (either average over 2 minutes or instantaneous) and used to calculate average methane concentration per hour
5.11 5.13	MM_i	Methane measured sent to use i	tCH_4	Continuous	m	Flow meters will record gas volumes, pressure and temperature
5.11 5.13	Eff_i	Efficiency of methane destruction through use i		Annually	m or r	See Appendix B
5.12	MMadjusted,i	adjusted volume of CMM collected for the given time interval at use i	scf/unit time	Every reporting period	c	adjusted to 60° F and 1 atm
5.12	MMunadjusted,i	unadjusted volume of CMM collected for the given time interval at use i	scf/unit time	Continuously	m	If flow meters do not internally correct for temperature and pressure

Eq. #	Parameter	Description	Data Unit	Measurement Frequency	Calculated (c) Measured (m) Reference (r) Operating records (o)	Comment
5.12	T	measured temperature of CMM for the given time period (° R = ° F + 460)	° R	Continuously	m	Measured to adjust the flow of CMM. No separate monitoring of temperature is necessary when using flow meters that automatically adjust flow volumes for temperature and pressure.
5.12	P	measured pressure of the CMM for the given time interval	Atm	Continuously	m	Measured to adjust the flow of CMM. No separate monitoring of pressure is necessary when using flow meters that automatically adjust flow volumes for temperature and pressure.

7 Reporting Parameters

This section provides requirements and guidance on reporting rules and procedures. A priority of the Reserve is to facilitate consistent and transparent information disclosure by project developers. Project developers must submit verified emission reduction reports to the Reserve annually at a minimum.

7.1 Project Documentation

Project developers must provide the following documentation to the Reserve in order to register a coal mine methane project.

- Project Submittal form
- Diagram of mine that illustrates how the project is defined and includes the location, quantity and type of boreholes, ventilation shafts, eligible destruction devices and non-qualifying destruction devices within project's GHG Assessment Boundary (project diagram)
- Signed Attestation of Title form
- Verification Report
- Verification Opinion
- Signed Regulatory Attestation form

Project developers must provide the following documentation each reporting period in order for the Reserve to issue CRTs for quantified GHG reductions:

- Verification Report
- Verification Opinion
- Signed Regulatory Attestation form

At a minimum, the above project documentation will be available to the public via the Reserve's online registry. Further disclosure and other documentation may be made available by the project developer on a voluntary basis. Project submittal forms can be found at http://www.climateactionreserve.org/how/projects/register/project-submittal-forms/.

7.1.1 Documentation of Project Expansions

If a project expands to include boreholes, ventilation shafts or destruction devices beyond what was included in the project as defined by the project developer at the time of listing (see Section 0), the project developer must submit an updated project diagram to the Reserve.

Similarly, if any new non-qualifying device become operational at the mine - or if an existing non-qualifying device at a mine is assigned to a different active project (see Section 2.2.3) - the project developer must submit an updated project diagram for the project to which the device is assigned.

7.2 Joint Project Verification

Because the protocol allows for multiple projects at a single mine site, project developers have the option to hire a single verification body to verify multiple projects at a mine through a "joint project verification". This may provide economies of scale for the project verifications and improve the efficiency of the verification process.

Under joint project verification, each project, as defined by the protocol and the project developer, is submitted, listed and registered separately in the Reserve system. Furthermore, each project requires its own separate verification process and Verification Opinion (i.e. each project is assessed by the verification body separately as if it were the only project at the mine). However, all projects may be verified together by a single site visit to the mine. Furthermore, a single Verification Report may be filed with the Reserve that summarizes the findings from multiple project verifications.

Regardless of whether the project developer chooses to verify multiple projects through a joint project verification or pursue verification of each project separately, the documents and records for each project must be retained according to this section.

7.3 Record Keeping

For purposes of independent verification and historical documentation, project developers are required to keep all information outlined in this protocol for a period of 10 years after the information is generated or 7 years after the last verification. This information will not be publicly available, but may be requested by the verifier or the Reserve.

System information the project developer should retain includes:

- All data inputs for the calculation of GHG reductions, including all required sampled data
- Copies of coal mine operating permits, air, water, and land use permits; Notices of Violations (NOVs); and any administrative or legal consent orders related to project activities dating back at least 3 years prior to the project start date; and for each subsequent year of project operation[19]
- Copies of mine plans and mine ventilation plans submitted to MSHA throughout the crediting period
- Executed Regulatory Attestation related to the CMM project
- Methane flow meter information (model number, serial number, manufacturer's calibration procedures)
- Methane monitor information (model number, serial number, calibration procedures)
- Destruction device monitor information (model number, serial number, calibration procedures)
- Field checks and calibration results for all meters
- Corrective measures taken if meter does not meet performance specifications
- Destruction device monitoring data (for each destruction device)
- CMM flow and methane concentration data
- Calculations that determined emission reductions
- Verification records and results from each verification
- All maintenance records relevant to the CMM monitoring equipment and destruction devices

7.4 Reporting Period & Verification Cycle

Project developers must report GHG reductions resulting from project activities during each reporting period. Although projects must be verified annually at a minimum, the Reserve will accept verified emission reduction reports on a sub-annual basis, should the project developer choose to have a sub-annual reporting period and verification schedule (e.g. quarterly or semi-

[19] Note that these documentation requirements are for activities and equipment related to the project only, not the entire mine.

annually). A reporting period cannot exceed 12 months, and no more than 12 months of emission reductions can be verified at once, except during a project's first verification, which may include historical emission reductions from prior years (see Section 3.2). Reporting periods must be contiguous; there can be no time gaps in reporting during the crediting period of a project once the initial reporting period has commenced.

8 Verification Guidance

This section provides verification bodies with guidance on verifying GHG emission reductions from coal mine methane projects developed to the standards of this protocol. This verification guidance supplements the Reserve's Verification Program Manual and describes verification activities in the context of coal mine methane destruction projects.

Verification bodies trained to verify coal mine methane projects must conduct verifications to the standards of the following documents:

- Climate Action Reserve Program Manual
- Climate Action Reserve Verification Program Manual
- Climate Action Reserve Coal Mine Methane Project Protocol

The Reserve's Program Manual, Verification Program Manual, and project protocols are designed to be compatible with each other and are available on the Reserve's website at http://www.climateactionreserve.org.

In cases where the Program Manual and/or Verification Program Manual differ from the guidance in this protocol, this protocol takes precedent.

Only ISO-accredited verification bodies trained by the Reserve for this project type are eligible to verify coal mine methane project reports. Verification bodies approved under other project protocol types are not permitted to verify coal mine methane projects. Information about verification body accreditation and Reserve project verification training can be found in the Verification Program Manual.

8.1 Verification of Multiple Projects at a Single Mine

Because the protocol allows for multiple projects at a single mine site, project developers have the option to hire a single verification body to verify multiple projects under a joint project verification. This may provide economies of scale for the project verifications and improve the efficiency of the verification process. Joint project verification is only available as an option for a single project developer; joint project verification cannot be applied to multiple projects registered by different project developers at the same mine.

Under joint project verification, each project, as defined by the protocol and the project developer, must still be registered separately in the Reserve system and each project requires its own verification process and Verification Opinion (i.e. each project is assessed by the verification body separately as if it were the only project at the mine). However, all projects may be verified together by a single site visit to the mine. Furthermore, a single Verification Report may be filed with the Reserve that summarizes the findings from multiple project verifications.

Finally, the verification body may submit one Notification of Verification Activities/Conflict of Interest (NOVA/COI) Assessment form that details and applies to all of the projects at a single mine that it intends to verify.

If, during joint project verification, the verification activities of one project are delaying the registration of another project, the project developer can choose to forego joint project verification. There are no additional administrative requirements of the project developer or the verification body if a joint project verification is terminated.

8.2 Standard of Verification

The Reserve's standard of verification for coal mine methane projects is the Coal Mine Methane Project Protocol (this document), the Reserve Program Manual, and the Verification Program Manual. To verify a coal mine methane project developer's project report, verification bodies apply the guidance in the Verification Program Manual and this section of the protocol to the standards described in Section 2 through 7 of this protocol. Sections 2 through 7 provide eligibility rules, methods to calculate emission reductions, performance monitoring instructions and requirements, and procedures for reporting project information to the Reserve.

8.3 Monitoring Plan

The Monitoring Plan serves as the basis for verification bodies to confirm that the monitoring and reporting requirements in Section 6 and Section 7 have been met, and that consistent, rigorous monitoring and record-keeping is ongoing at the project site. Verification bodies shall confirm that the Monitoring Plan covers all aspects of monitoring and reporting contained in this protocol and specifies how data for all relevant parameters in Table 6.1 are collected and recorded.

8.4 Verifying Project Eligibility

Verification bodies must affirm a coal mine methane project's eligibility according to the rules described in this protocol. The table below outlines the eligibility criteria for a coal mine methane project. This table does not represent all criteria for determining eligibility comprehensively; verification bodies must also look to Section 3 and the verification items list in Table 8.2.

Table 8.1. Summary of Eligibility Criteria

Eligibility Rule	Eligibility Criteria	Frequency of Rule Application
Start Date	For 12 months following the Effective Date of this protocol, a pre-existing project with a start date on or after October 7, 2007 may be submitted for listing; after this 12 month period, projects must be submitted for listing within 6 months of the project start date	Once during first verification
Location	United States and its territories	Once during first verification
Performance Standard	▪ Drainage projects: the project destroys CMM through any end use destruction system other than injection into a natural gas pipeline for off-site consumption ▪ All VAM projects	Once during first verification
Legal Requirement Test	Signed Regulatory Attestation form and monitoring procedures that lay out procedures for ascertaining and demonstrating that the project passes the Legal Requirement Test	Every verification
Regulatory Compliance Test	Project must be in material compliance with all applicable laws	Every verification

Eligibility Rule	Eligibility Criteria	Frequency of Rule Application
Exclusions	▪ Surface coal mines ▪ Abandoned coal mines ▪ Coal bed methane destruction ▪ Use of CO_2 or other fluid/gas to enhance methane drainage before mining takes place	Every verification

8.5 Core Verification Activities

The Coal Mine Methane Project Protocol provides explicit requirements and guidance for quantifying GHG reductions associated with the destruction of coal mine methane. The Verification Program Manual describes the core verification activities that shall be performed by verification bodies for all project verifications. They are summarized below in the context of a coal mine methane project, but verification bodies shall also follow the general guidance in the Verification Program Manual.

Verification is a risk assessment and data sampling effort designed to ensure that the risk of reporting error is assessed and addressed through appropriate sampling, testing, and review. The three core verification activities are:

1. Identifying emissions sources, sinks and reservoirs
2. Reviewing GHG management systems and estimation methodologies
3. Verifying emission reduction estimates

Identifying emission sources, sinks, and reservoirs
The verification body reviews for completeness the sources, sinks, and reservoirs identified for a project, such as VAM and CMM destruction system energy use, fuel consumption from transport of the gas, combustion and destruction from various qualifying and non-qualifying destruction devices, and emissions from the incomplete combustion of methane.

Reviewing GHG management systems and estimation methodologies
The verification body reviews and assesses the appropriateness of the methodologies and management systems that the coal mine operator uses to gather data on methane collected and destroyed and to calculate baseline and project emissions.

Verifying emission reduction estimates
The verification body further investigates areas that have the greatest potential for material misstatements and then confirms whether or not material misstatements have occurred. This involves site visits to the project to ensure the systems on the ground correspond to and are consistent with data provided to the verification body. In addition, the verification body recalculates a representative sample of the performance or emissions data for comparison with data reported by the project developer in order to double-check the calculations of GHG emission reductions.

8.6 Coal Mine Methane Verification Items

The following tables provide lists of items that a verification body needs to address while verifying a coal mine methane project. The tables include references to the section in the protocol where requirements are further described. The table also identifies items for which a verification body is expected to apply professional judgment during the verification process. Verification bodies are expected to use their professional judgment to confirm that protocol requirements have been met in instances where the protocol does not provide (sufficiently) prescriptive guidance. For more information on the Reserve's verification process and professional judgment, please see the Verification Program Manual.

Note: These tables shall not be viewed as a comprehensive list or plan for verification activities, but rather guidance on areas specific to coal mine methane projects that must be addressed during verification.

8.6.1 Project Eligibility and CRT Issuance

Table 8.2 lists the criteria for reasonable assurance with respect to eligibility and CRT issuance for coal mine methane projects. These requirements determine if a project is eligible to register with the Reserve and/or have CRTs issued for the reporting period. If any one requirement is not met, either the project may be determined ineligible or the GHG reductions from the reporting period (or sub-set of the reporting period) may be ineligible for issuance of CRTs, as specified in Sections 2, 3, and 6.

Table 8.2. Eligibility Verification Items

Protocol Section	Eligibility Qualification Item	Apply Professional Judgment?
2.2 - 2.2.2	Verify that the project meets the definition of a CMM project and is properly defined as either drainage project or VAM project	No
2.2.3	Confirm all non-qualifying devices have been properly accounted for within project's GHG Assessment Boundary	No
2.3	Verify ownership of the reductions by reviewing Attestation of Title	No
2.2.1 - 2.2.3, 7.1.1	If there are new destruction devices, boreholes, shafts or a project crediting period expiration at the mine, verify that project expansions have been completed, properly defined and documented to account for these changes	No
3.1	Verify that the project only consists of activities at a single coal mine or Category III gassy underground trona mine operating within the U.S. or its territories	No
3.2	Verify eligibility of project start date	No
3.2	Verify accuracy of project start date based on operational records	Yes
3.3	Verify that project is within its 10 year crediting period	No
3.4.1	Confirm execution of the Regulatory Attestation form to demonstrate eligibility under the Legal Requirement Test	No
3.4.1	Verify that the project monitoring plan contains procedures for ascertaining and demonstrating that the project passes the Legal Requirement Test at all times	Yes
3.4.2	Verify that the project meets the appropriate Performance Standard Test for the project type	No
3.4.2	If VAM project uses supplemental CMM, verify that supplemental CMM is eligible	No
3.5	Verify that the project activities comply with applicable laws by reviewing any instances of non-compliance provided by the project developer and performing a risk-based assessment to confirm the statements made by the project developer in the Regulatory Attestation form	Yes
6.1	Verify that monitoring meets the requirements of the protocol. If it does not, verify that a variance has been approved for monitoring variations.	No
6.1	Verify that NMHC samples were properly collected and analyzed	No
6.2	Verify that all gas flow meters and continuous methane analyzers adhered	No

Protocol Section	Eligibility Qualification Item	Apply Professional Judgment?
	to the inspection, cleaning, and calibration schedule specified in the protocol. If they do not, verify that a variance has been approved for monitoring variations or that adjustments have been made to data per the protocol requirements	
6.2	Verify that any portable calibration instruments were calibrated at least annually by the manufacturer or at an ISO 17025 accredited lab	No
6.2	If any piece of equipment failed a calibration check, verify that data from that equipment was scaled according to the failed calibration procedure for the appropriate time period	No
6.3, Appendix C	If used, verify that data substitution methodology was properly applied	No
n/a	If any variances were granted, verify that variance requirements were met and properly applied	Yes

8.6.2 Quantification of GHG Emission Reductions

Table 8.3 lists the items that verification bodies shall include in their risk assessment and re-calculation of the project's GHG emission reductions. These quantification items inform any determination as to whether there are material and/or immaterial misstatements in the project's GHG emission reduction calculations. If there are material misstatements, the calculations must be revised before CRTs are issued.

Table 8.3. Quantification Verification Items

Protocol Section	Quantification Item	Apply Professional Judgment?
4	Verify that SSRs included in the GHG Assessment Boundary correspond to those required by the protocol and those represented in the project diagram for the reporting period	No
5.1	Verify that the project developer correctly accounted for methane destruction in the baseline scenario	No
5.1	Verify that baseline emissions for non-qualifying devices were calculated according to the protocol	No
5.1.2.1	Verify definition of mined through was properly applied to SMM boreholes	No
5.2.2	Verify NMHC concentration of CMM is either below project-specific threshold or, if above, CO_2 emissions from NMHC combustion are accounted for in project emissions	No
5.2.1	Verify that the project developer correctly quantified and aggregated electricity use	Yes
5.2.1	Verify that the project developer correctly quantified and aggregated fossil fuel use	Yes
5.2.1	Verify that the project developer correctly quantified and aggregated heat consumption	Yes
Equation 5.8, Appendix B	Verify that the project developer applied the correct emission factors for fossil fuel combustion and grid-delivered electricity	No
Equation 5.11, Appendix B	Verify that the project developer applied the correct methane destruction efficiencies	No
Equation 5.11	If the project developer used source test data in place of the default destruction efficiencies (Appendix B), verify accuracy and appropriateness of data and calculations	Yes

8.6.3 Risk Assessment

Verification bodies will review the following items in Table 8.4 to guide and prioritize their assessment of data used in determining eligibility and quantifying GHG emission reductions.

Table 8.4. Risk Assessment Verification Items

Protocol Section	Item that Informs Risk Assessment	Apply Professional Judgment?
6	Verify that the project monitoring plan is sufficiently rigorous to support the requirements of the protocol and proper operation of the project	Yes
6	Verify that the methane destruction equipment was operated and maintained according to manufacturer specifications	Yes
6	Verify that appropriate monitoring equipment is in place to meet the requirements of the protocol	No
6	Verify that the individual or team responsible for managing and reporting project activities are qualified to perform this function	Yes
6	Verify that appropriate training was provided to personnel assigned to greenhouse gas reporting duties	Yes
6	Verify that all contractors are qualified for managing and reporting greenhouse gas emissions if relied upon by the project developer. Verify that there is internal oversight to assure the quality of the contractor's work	Yes
7.3	Verify that all required records have been retained by the project developer	No

8.7 Completing Verification

The Verification Program Manual provides detailed information and instructions for verification bodies to finalize the verification process. It describes completing a Verification Report, preparing a Verification Opinion, submitting the necessary documents to the Reserve, and notifying the Reserve of the project's verified status.

As stated in Section 8.1, project developers may choose to have a verification body conduct multiple project verifications at a single mine under a joint project verification. The verification body must verify the emission reductions entered into the Reserve system for each project and upload a unique Verification Opinion for each project within the joint verification. The verification body can prepare a single Verification Report that contains information on all of the projects, but this must also be uploaded to every project under the joint verification.

9 Glossary of Terms

Active mine	Active mines include mine works that are actively ventilated by the coal mine operator. For the purposes of this protocol, MSHA designated "intermittent" mines are also considered active mines.
Abandoned mine	A mine where all mining activity including mine development and mineral production have ceased, mine personnel are not present in the mine workings, and mine ventilation fans are no longer operative.[20] In the U.S., coal mines are declared "abandoned" from the date when ventilation is discontinued.[21] This mine type is not eligible under this protocol.
Baseline emissions	Baseline emissions represent the GHG emissions within the GHG Assessment Boundary that would have occurred in the absence of the GHG reduction project.
Coal bed methane (CBM)	A generic term for methane originating in coal seams that is drained from virgin coal seams and surrounding strata. CBM is unrelated to mining activities.
Coal mine gas (CMG)	Gas from drainage systems before any processing or enrichment that often contains various levels of other components (e.g. nitrogen, oxygen carbon dioxide, hydrogen sulfide, NMHC, etc.).
Coal mine methane (CMM)	Methane contained in coal and surrounding strata that is released because of mining activity. For the purposes of this protocol, CMM also refers to the methane gas that is released because of mining activity at Category III gassy underground trona mines.
Drainage system	A term used to encompass the entirety of the equipment that is used to drain the gas from underground and collect it at a common point, such as a vacuum pumping station. In this protocol, methane drainage systems include surface pre-mining, horizontal pre-mining, and post-mining.
Effective Date	The date of adoption of this protocol by the Reserve board: October 7, 2009.

[20] UN Economic and Social Council, Economic Commission for Europe, Committee on Sustainable Energy, Glossary of Coal Mine Methane Terms and Definitions, July 2008.
[21] MSHA Program Policy Manual Volume V, January 2006, p.120.

Eligible end use	For the purposes of this protocol, all end uses that result in the destruction/oxidation of methane except for injection into natural gas pipeline.
Gob	Also referred to as goaf, it is the collapsed area of strata produced by the removal of coal and artificial supports behind a working coalface. Strata above and below the gob are de-stressed and fractured by the mining activity.
Intermittent	Mines placed in intermittent status by MSHA, as a result of being seasonally idled for more than 90 days, are not considered abandoned. To maintain intermittent status, facilities and equipment such as the mine office, surface and underground power systems, the main mine fan, and underground coal haulage systems must remain intact.[22] Under this protocol, intermittent mines are considered active mines and are eligible.
Joint project verification	Project verification option where a project developer hires a verification body to verify multiple projects at a mine.
Longwall mine	An underground mining type that uses at least one longwall panel during coal excavation.
Mine Safety and Health Administration (MSHA)	Federal enforcement agency responsible for protecting the health and safety of U.S. miners.
Mined through	When the linear distance between the endpoint of the borehole and the working face that will pass nearest the endpoint of the borehole has reached an absolute minimum. Coal mine methane from surface pre-mining boreholes shall not be quantified in the baseline until the endpoint of the borehole is mined through.
Mine	An area of land and all structures, facilities, machinery tools, equipment, shafts, slopes, tunnels, excavations, and other property, real or personal, placed upon, under, or above the surface of such land by any person, used in, or to be used in, or resulting from, the work of extracting minerals. The mine boundaries are defined by the mine area as permitted by the state in which the mine is located.
Non-qualifying destruction device	A methane destruction device that does not meet one or more of the eligibility rules as described in Section 3 (e.g. operational start date, regulatory requirement, injection into natural gas pipeline) and is located at the same mine where eligible project activities are taking place.

[22] MSHA Program Policy Manual, p.138.

Oxidizer	For the purposes of this protocol, the term oxidizer refers to technology for destruction of ventilation air methane with or without utilization of thermal energy and/or with or without a catalyst.
Project diagram	A diagram of the mine that illustrates the location, quantity, and type of boreholes, ventilations shafts, eligible destruction devices and non-qualifying destruction devices within a project's GHG Assessment Boundary. The project diagram must be updated and submitted to the Reserve whenever a project expansion occurs.
Project emissions	Project emissions are actual GHG emissions that occur within the GHG Assessment Boundary as a result of project activities. Project emissions are calculated at a minimum on an annual, *ex-post* basis.
Qualifying destruction device	A methane destruction device that meets the eligibility rules for a CMM project as described in Section 3.
Room and pillar mine	An underground mining type that uses square or rectangular pillars of coal during excavation, laid out in a checkerboard fashion. Pillars typically range in size from 60 feet by 60 feet to 100 feet by 100 feet and rooms are typically 20 feet wide and a few thousand feet long
Reporting period	Specific time period of project operation for which the project developer has calculated and reported emission reductions and is seeking verification and registration. The reporting period must be no longer than 12 months.
Ventilation air methane (VAM)	Coal mine methane that is mixed with the ventilation air in the mine that is circulated in sufficient quantity to dilute methane to low concentrations for safety reasons (typically below 1 percent).
Ventilation system	A system that is used to control the concentration of methane and other deleterious gases within mine working areas. Ventilation systems consist of powerful fans that move large volumes of air through the mine workings to dilute methane concentrations. All underground coal mines in the U.S. are required to develop and maintain ventilation systems.
Verification cycle	The Reserve requires verification of coal mine methane projects annually, but does not require verifications to be completed on specific dates. Project developers select the reporting period to be

	verified. Thus, each project has a unique verification cycle that begins the first time a project is verified, occurs at least annually, and ends once the crediting period expires or the project is no longer eligible, whichever happens first.
Year	For the purposes of this protocol, year refers to a 12 month period of the project's crediting period, not a calendar year.

10 References

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Appendix A Summary of Performance Standard Development

The analysis to develop the performance standard for the Coal Mine Methane Project Protocol was conducted by Science Applications International Corporation (SAIC) and was completed in May 2009. The analysis culminated in a paper that provided a performance standard recommendation to support the coal mine methane protocol development process, which the Reserve has incorporated into the protocol's eligibility rules (see Section 3).

The purpose of a performance standard is to establish a standard of performance applicable to all coal mine methane management projects that is significantly better than average greenhouse gas production for a specified service, which, if met or exceeded by a project developer, satisfies one of the criterion of "additionality".

The performance standard analysis contained an in-depth study of the following areas:

- Coal mine data trends and regional variations across the U.S.
- Degasification techniques including ventilation, surface pre-mining drainage, horizontal pre-mining drainage, and post-mining gob drainage currently used in coal mines
- Ventilation air methane utilization technologies
- Review of current, pending and anticipated regulations that could affect coal mine methane projects
- Data analysis to establish common practice for coal mine methane management at underground coal mines in the U.S.

Overview of Data Collection

The primary database used for the SAIC analysis was a coal mine methane emissions database provided by the U.S. EPA. [23] This database provided annual emissions-related data for underground mines classified as gassy by MSHA; the data cover the period 1990 through 2007. For the purposes of this analysis, the annual data for the 2000 to 2007 timeframe was used, covering a total of 295 gassy underground mines. The database provides the following data:

- Company name, mine name, and 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
- An indication as to whether the drained methane is captured, and a brief description of how the captured methane is utilized
- Detailed information on the subset of mines using methane capture

To supplement this primary data set, EPA provided a second database containing annual coal production data for the gassy mines for the years 2002 through 2006, along with an indication of

[23] This database is used as the basis for the coal mine methane emissions estimated published in EPA's annual *Inventory of U.S. Greenhouse Gas Emissions and Sinks* reports.

the mine's production status. [24] SAIC also used mine-level production data for 2000, 2001, and 2007, obtained from the Energy Information Administration (EIA). [25] SAIC merged the production data with the emissions database using each mine's MSHA identification number. The final merged dataset included 241 mines for which emissions data for at least one of the eight years in the 2000-2007 time frame was available.

EPA also provided a list of longwall mines in the United States that produced in excess of 750,000 tons of coal from January through September 2007, published by CoalUSA magazine. This list was supplemented by SAIC with similar CoalUSA lists for production from 2001 through 2006[26] and a table detailing the production of top non-longwall mines in 2007.[27] SAIC also consulted the mining method information contained in two EPA reports on methane recovery opportunities at gassy mines.[28] They combined the mines on these lists to create a master list of longwall mines in operation during the 2000 to 2007 time period. The master list represents a comprehensive list of longwall mines operating in and around 2007 with the following assumptions:

- The individual lists provide a comprehensive identification of all longwall mines falling above the production cutoff
- Most, if not all, longwall mines would meet the production cutoff when operating at full capacity
- Most, if not all, longwall mines would have operated at full capacity at least in one year during the 2000 to 2007 time period

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, a longwall mine is defined as any mine that has at least one longwall face or that opened a longwall face at some point during the 2000-2007 period.

In combining and using the data for eight separate years into a single dataset, SAIC 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, SAIC treated the mine as using both drainage system types during the 2000 to 2007 time frame. Similarly, mines that utilized methane in some years but not in others were treated as having utilization projects in operation in the 2000 to 2007 time frame. The decision to use and combine data for the past eight years into a single dataset was based on a trend analyses which indicated that industry practice with respect to drainage systems and utilization projects has remained fairly stable since 2000 (see Table A.1). Given

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[24] EIA was the original source of the production data.
[25] EIA, http://www.eia.doe.gov/cneaf/coal/page/database.html.
[26] Weir International, Inc. 2008. "U.S. 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 U.S. Longwall Mine Production and Productivity; "Table: U.S. Longwall Production 2005," *International Longwall News*, 27 March, 2006. At: http://www.longwalls.com/sectionstory.asp?SourceID=s50; NIOSH, 2005. "Table: U.S. Longwall production 2004." *International Longwall News*, 23 March 2005; NIOSH, 2004. "Table: U.S. Longwall output 2003 now working." *International Longwall News*, 7 April 2004; NIOSH, 2003. "Table: U.S. Longwall output 2002." *International Longwall News*, 21 July 2003.
[27] Weir International, Inc. 2008. "Top 50 U.S. Underground Mines (non-longwall) – Production and Productivity: September 2007 Year to Date." *CoalUSA*, March 2008. *CoalUSA*, March 2008.
[28] U.S. EPA, *Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 1999-2003* and *Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 2002-2006*.

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.

Table A.1. Historical Trends in 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	n/a	n/a	n/a	8	11	15	12	12
Mines with Gob and Horizontal Pre-Mining Wells	n/a	n/a	n/a	3	3	3	3	3
Mines with All 3 Drainage System Types	n/a	n/a	n/a	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
*Mine also sells a portion of its recovered methane to a pipeline.								

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

Trona Mines

Data on trona mines operating in the United States was also collected and examined.[29] There are four Category III gassy underground trona mines in the United States, of which two are room and pillar and two are longwall mines. The two longwall mines currently have gob wells, but neither is capturing the coal mine methane for destruction.

Summary of Analysis

Should the Performance Standard Include the Drainage System?

In order to establish the definition of a coal mine methane project, it was necessary to explore if the installation of a drainage system should be tested using a performance standard, or if the performance standard test could be limited to the installation of coal mine methane destruction devices.

The hypothesis was that federal health and safety regulations influence a coal mine operator's decision to install methane drainage systems. As stated in Section 3.4.1, 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 test 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

[29] Coal Age *U.S. Longwall Census*, February 2009. MSHA ID numbers and liberation rates provided by Steven Pilling, MSHA Green River, Wyoming Field Office, June 2009. Information on drainage systems provided by Jeff Liebert, Verdeo Group, July 2009.

considered a part of an additional coal mine methane project. In other words, the safety regulations may have important implications for determining the project definition and eligibility rules. Specifically, the methane drainage system may need to be excluded from the project definition if the system was developed as a response to the safety regulations. If this is the case, the methane drainage system does not pass the regulatory test but the methane destruction system may; the project definition should thus include only the destruction system.

To test this hypothesis, SAIC therefore conducted an analysis to determine the common practices utilized by coal mine operators to dilute methane concentrations as a function of methane liberation rates. As a first step in their data analysis, they computed arithmetic averages of the annual methane liberation data for each mine in the merged emissions dataset. However, 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.

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 SAIC 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. They then multiplied this methane liberation rate by the largest of the eight annual production data points in the 2000-07 timeframe to obtain their 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.[30] 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 they likewise sought to base their analysis on full capacity conditions. They 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 they 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 the analysis. The single longwall mine lacking production data does not employ a drainage system.

Figure A.1 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. This histogram indicates that the use of methane drainage is highly correlated with the quantity of

[30] 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.

methane produced by a longwall mine. From these results, methane drainage can be considered a common practice for gassy longwall mines.

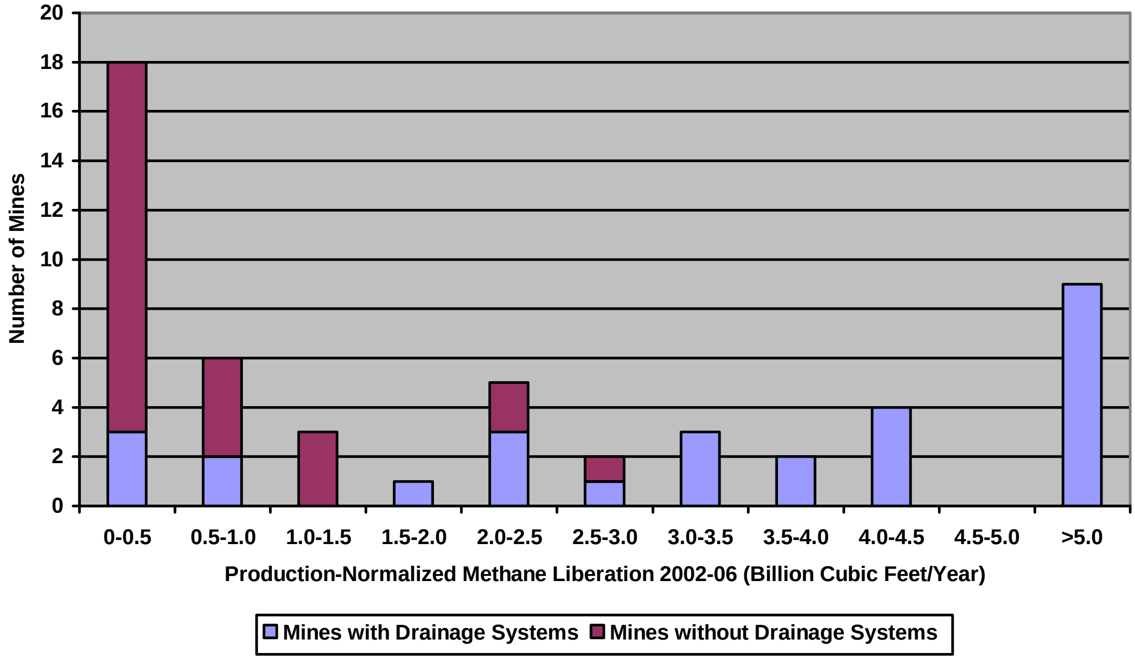

Figure A.1. Histogram of Drainage System Usage by Longwall Mines

There are currently no room and pillar mines with drainage systems in place; there are also no room and pillar mines with either arithmetic average or production-normalized methane liberation quantities in excess of 2 billion cubic feet.

Conclusion

This analysis strongly supports the hypothesis that the drainage systems currently in place are a response to the regulations. Given these results, we assume that all drainage systems are a response to health and safety regulations. Thus, the installation of a drainage system is not included in the definition of a coal mine methane project and is not tested for by a performance standard.

Recommendation to Use a Common Practice Standard

With the conclusion that the performance standard test must only test the additionality of the installation of a destruction device, it was necessary to determine what type of performance standard test was most suitable for coal mine methane projects.

Coal mine methane projects do not lend themselves to rate- or technology-based comparisons. In general, all coal mine methane projects are characterized by a very high rate of capture, making it difficult to distinguish projects on the basis of a metric such as methane destroyed as a percentage of methane entering the destruction device. Other potential metrics that might be used to establish a performance threshold for coal mine methane projects, such as the total quantity of methane captured on an annual basis, are fraught with difficulties. 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 general, there are no current requirements - federal, state, or local - that should influence a mine operator's choice between venting and utilizing the methane drained from drainage systems. This choice is driven by economic considerations, not regulatory requirements. A common practice standard is well-suited for these projects, in so far as common practice can help us infer whether the decision to install a methane destruction device was influenced by the availability of funding from carbon credits. Specifically, by identifying the conditions under which methane destruction is currently common practice, we can infer that projects operating under those conditions are likely undertaken to use the gas as a valuable byproduct of the mining process, and thus not additional.

Drainage Project Analysis

A strong argument can be made for determining additionality by assessing common practice of coal mine methane destruction by utilization type. As previously noted in Table A.1, only a small number of the mines with known utilization projects use the captured methane for purposes other than for sales to pipelines.

To test this hypothesis, SAIC analyzed a subset of the merged emissions/production database they created. Because the interest here is in mines that already utilize methane drainage systems, they eliminated all mines from the merged dataset that did not employ methane drainage at any time during the 2000-07 timeframe. Following this elimination, they 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. In addition to data on the total annual amount of methane liberated in 2000-07, this new database included 2000-07 data on the annual amount of methane drained and vented at each of the 28 mines. The data set also provided 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.).

A close review of the 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 original EPA data 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. Because of this anomaly, they treated 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 a utilization project for the purposes of the analysis. See Table A.2 for a summary of this database.

Table A.2. Summary of Drainage System Type and Utilization at Longwall Coal Mines

MSHA ID	State Location	Utilization*	Drainage System Type(s)**
100851	AL	P	GHS
101247	AL	P	GHS
101322	AL	P	GHS
101401	AL	P	GHS
102901	AL	P	GH
503672	CO	H	GH
504452	CO	N	G
504591	CO	N	G
504758	CO	N	G
1514492	KY	N	U
2902170	NM	P	GH
3604281	PA	N	U
3605018	PA	P	G
3605466	PA	P	G
3605466	CO	N	G
3607230	PA	E	G
3607416	PA	N	G
4201890	UT	N	G
4202028	UT	P	G
4403795	VA	P	GHS
4404856	VA	P & TD	GHS
4601318	WV	N	GH
4601433	WV	P	GH
4601436	WV	N	GH
4601437	WV	N	G
4601456	WV	P & E	GH
4601816	WV	P	GHS
4601968	WV	P	GH

*P = Pipeline injection
E = Electricity generation
TD = Thermal coal drying
H = Mine ventilation air heating
N = None

**G = Gob wells
H = Horizontal pre-mine wells
S = Vertical pre-mine wells
U = Unknown

Results

Analysis of the new database found that:

- 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, one might hypothesize that pipeline projects are in effect distorting the 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, SAIC eliminated all of the mines with pipeline sales projects from the database, and considered 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 not a barrier to the application of other end uses. However, before performing this analysis, it was necessary to 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. It appears that these two projects are not being adversely affected by competition from pipeline projects, as they co-exist with the latter. 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 sub-economic, rather than merely less economic than pipeline sales projects. It was determined that the two co-located on-site projects should be excluded from the analysis, because competition from pipeline sales projects 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, SAIC drew 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 currently captures methane to generate electricity
- Only one of the 12 mines (eight percent) that utilize drainage systems *not* connected to natural gas pipelines currently captures methane to heat the mine ventilation air.

Based on the above analysis SAIC concluded 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. 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.

The Reserve believes 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.

Regional Analysis

An additional analysis was conducted to assess whether common practice with respect to utilization 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 utilization. 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 A.3. Regional Analysis of Methane Utilization 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		
	Mines with Drainage Systems	Mines with Utilization	Percent with Utilization	Mines with Drainage Systems	Mines with Utilization	Percent with Utilization
Pennsylvania	3	3	100	1	0	0
W. Virginia	6	4	67	1	0	0
Virginia	2	2	100	0	0	n/a
Kentucky	0	0	NA	1	0	0
Alabama	5	5	100	0	0	n/a
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	n/a
Western U.S.	**5**	**3**	**60**	**3**	**0**	**0**
Total U.S.	**21**	**17**	**81**	**6**	**0**	**0**

Table A.3 presents the results of the regional analysis. It 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 captures and utilizes 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 SAIC recommended against establishing regional variations in the common practice standards for coal mine methane projects.

Conclusion

Based on the above analysis of current utilization project types, the Reserve concluded that all projects designed to utilize the methane for any purpose other than pipeline sales shall be eligible 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. Projects that include both pipeline sales and other uses (e.g. electricity generation) are to be treated as two separate projects for the purposes of applying the common practice standard, and the project involving uses other than pipeline sales are to be eligible under the common practice standard.
Because of similarities between the regulatory requirements, operating conditions, mining methods, and methane management of gassy underground trona mines and coal mines, the Reserve concluded the same common practice standard also applies to trona mines categorized as MSHA Category III gassy underground metal and non-metal mines.

Ventilation Air Methane Projects

There is opportunity for achieving significant reductions in coal mine methane emissions from 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 A.2). However, the technology available to tap into this 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 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 much higher methane content.

There are at present no commercial projects using ventilation air methane destruction or oxidation technology at active coal or trona mines in the United States.[31] Since commercial VAM projects are non-existent at present, the Reserve concludes that all commercial VAM projects be eligible under a common practice standard.

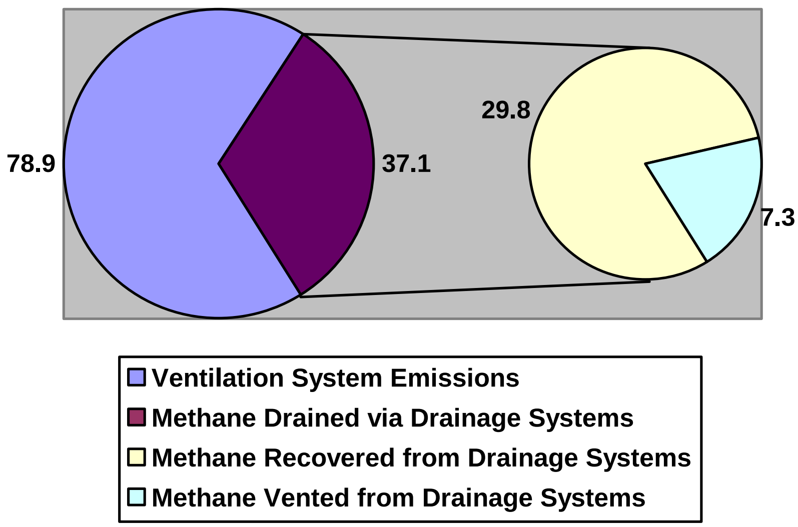

Figure A.2. Ventilation and Drainage System Emissions, 2007 (million cubic feet)

Evaluation of the Common Practice Standards

The common practice standards summarized above are 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 utilization, which is small. With the exception of a very small number of mines with missing data that were deleted from the database, the Reserve believes the 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 primary sources provide comprehensive coverage of all gassy mines, all mines with drainage, and all mines with utilization, this is the intent of these databases and we have no reason to believe that there are significant deficiencies in their coverage.

[31] There is one demonstration project that received approval from the Mine Health and Safety Administration (MSHA) in April 2008.

Thus, while the analysis necessarily rests on a small set of observations, it is nonetheless representative of the population. By pooling the data across eight years (2000-07), SAIC was able to increase the number of mines covered in the 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. Beyond pooling the data, there are few if any viable means of increasing the number of observations used in this 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.

Updating the Performance Standard

The common practice standards developed for coal mine methane projects reflect operating practices under current economic, regulatory, and technological conditions. SAIC's analysis of sector trends indicated that common practice has been relatively stable or slow to evolve, at least over the past decade. If and when these conditions change in the future, the common practice standard will be affected. Therefore, the performance standard analyses will be updated on a periodic basis to either confirm that common practice has not changed or to develop new standards reflecting changed conditions.

Appendix B Emission Factor Tables

Table B.1. CO_2 Emission Factors for Fossil Fuel Use

Fuel Type	Heat Content	Carbon Content (Per Unit Energy)	Fraction Oxidized	CO_2 Emission Factor (Per Unit Energy)	CO_2 Emission Factor (Per Unit Mass or Volume)
Coal and Coke	**MMBtu / Short ton**	**kg C / MMBtu**		**kg CO_2 / MMBtu**	**kg CO_2 / Short ton**
Anthracite Coal	25.09	28.26	1.00	103.62	2,599.83
Bituminous Coal	24.93	25.49	1.00	93.46	2,330.04
Sub-bituminous Coal	17.25	26.48	1.00	97.09	1,674.86
Lignite	14.21	26.30	1.00	96.43	1,370.32
Unspecified (Residential/ Commercial)	22.05	26.00	1.00	95.33	2,102.29
Unspecified (Industrial Coking)	26.27	25.56	1.00	93.72	2,462.12
Unspecified (Other Industrial)	22.05	25.63	1.00	93.98	2,072.19
Unspecified (Electric Utility)	19.95	25.76	1.00	94.45	1,884.53
Coke	24.80	31.00	1.00	113.67	2,818.93
Natural Gas (By Heat Content)	**Btu / Standard cubic foot**	**kg C / MMBtu**		**kg CO_2 / MMBtu**	**kg CO_2 / Standard cub. ft.**
975 to 1,000 Btu / Std cubic foot	975 – 1,000	14.73	1.00	54.01	Varies
1,000 to 1,025 Btu / Std cubic foot	1,000 – 1,025	14.43	1.00	52.91	Varies
1,025 to 1,050 Btu / Std cubic foot	1,025 – 1,050	14.47	1.00	53.06	Varies
1,050 to 1,075 Btu / Std cubic foot	1,050 – 1,075	14.58	1.00	53.46	Varies
1,075 to 1,100 Btu / Std cubic foot	1,075 – 1,100	14.65	1.00	53.72	Varies
Greater than 1,100 Btu / Std cubic foot	> 1,100	14.92	1.00	54.71	Varies
Weighted U.S. Average	1,029	14.47	1.00	53.06	0.0546
Petroleum Products	**MMBtu / Barrel**	**kg C / MMBtu**		**kg CO_2 / MMBtu**	**kg CO_2 / gallon**
Asphalt & Road Oil	6.636	20.62	1.00	75.61	11.95
Aviation Gasoline	5.048	18.87	1.00	69.19	8.32
Distillate Fuel Oil (#1, 2 & 4)	5.825	19.95	1.00	73.15	10.15
Jet Fuel	5.670	19.33	1.00	70.88	9.57
Kerosene	5.670	19.72	1.00	72.31	9.76
LPG (average for fuel use)	3.849	17.23	1.00	63.16	5.79
Propane	3.824	17.20	1.00	63.07	5.74
Ethane	2.916	16.25	1.00	59.58	4.14
Isobutene	4.162	17.75	1.00	65.08	6.45
n-Butane	4.328	17.72	1.00	64.97	6.70
Lubricants	6.065	20.24	1.00	74.21	10.72
Motor Gasoline	5.218	19.33	1.00	70.88	8.81
Residual Fuel Oil (#5 & 6)	6.287	21.49	1.00	78.80	11.80
Crude Oil	5.800	20.33	1.00	74.54	10.29
Naphtha (<401 deg. F)	5.248	18.14	1.00	66.51	8.31
Natural Gasoline	4.620	18.24	1.00	66.88	7.36
Other Oil (>401 deg. F)	5.825	19.95	1.00	73.15	10.15
Pentanes Plus	4.620	18.24	1.00	66.88	7.36
Petrochemical Feedstocks	5.428	19.37	1.00	71.02	9.18
Petroleum Coke	6.024	27.85	1.00	102.12	14.65
Still Gas	6.000	17.51	1.00	64.20	9.17
Special Naphtha	5.248	19.86	1.00	72.82	9.10
Unfinished Oils	5.825	20.33	1.00	74.54	10.34
Waxes	5.537	19.81	1.00	72.64	9.58

Source: EPA Climate Leaders, Stationary Combustion Guidance (2007), Table B-2 except:
Default CO_2 emission factors (per unit energy) are calculated as: Carbon Content × Fraction Oxidized × 44/12.
Default CO_2 emission factors (per unit mass or volume) are calculated as: Heat Content x Carbon Content × Fraction Oxidized × 44/12× Conversion Factor (if applicable).

Heat content factors are based on higher heating values (HHV).

If available, the official source tested methane destruction efficiency shall be used in place of the default methane destruction efficiency. Project developers have the option to use either the default methane destruction efficiencies provided, or the site specific methane destruction efficiencies as provided by a state or local agency accredited source test service provider, for each of the combustion devices used in the project, performed on an annual basis.

Table B.2. Default Destruction Efficiencies for Combustion Devices

Destruction Device	Destruction Efficiency
Open Flare	0.96
Enclosed Flare	0.995
Lean-burn Internal Combustion Engine	0.936
Rich-burn Internal Combustion Engine	0.995
Boiler	0.98
Microturbine or large gas turbine	0.995
Upgrade and use of gas as CNG/LNG fuel	0.95
Upgrade and injection into natural gas pipeline	0.98**

Source: The default destruction efficiencies for enclosed flares and electricity generation devices are based on a preliminary set of actual source test data provided by the Bay Area Air Quality Management District. The default destruction efficiency values are the lesser of the twenty fifth percentile of the data provided or 0.995. These default destruction efficiencies may be updated as more source test data is made available to the Reserve.

**** The Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories gives a standard value for the fraction of carbon oxidized for gas destroyed of 99.5% (Reference Manual, Table 1.6, page 1.29). It also gives a value for emissions from processing, transmission and distribution of gas which would be a very conservative estimate for losses in the pipeline and for leakage at the end user (Reference Manual, Table 1.58, page 1.121). These emissions are given as 118,000kgCH_4/PJ on the basis of gas consumption, which is 0.6%. Leakage in the residential and commercial sectors is stated to be 0 to 87,000kgCH_4/PJ, which equates to 0.4%, and in industrial plants and power station the losses are 0 to 175,000kg/CH_4/PJ, which is 0.8%. These leakage estimates are compounded and multiplied. The methane destruction efficiency for landfill gas injected into the natural gas transmission and distribution system can now be calculated as the product of these three efficiency factors, giving a total efficiency of (99.5% * 99.4% * 99.6%) 98.5% for residential and commercial sector users, and (99.5% * 99.4% * 99.2%) 98.1% for industrial plants and power stations. [32]

Equation B.1. Calculating Heat Generation Emission Factor ($EF_{heat,y}$)

$$EF_{heat,y} = \frac{EF_{CO_2,i}}{Eff_{heat}} \times \frac{44}{12}$$

Where,			Units
$EF_{heat,y}$	=	Emission factor for heat generation	kg CO_2/volume
$EF_{CO2,i}$	=	CO_2 emission factor of fuel used in heat generation (see Table B.1)	kg C/volume
Eff_{heat}	=	Boiler efficiency of the heat generation (either measured efficiency, manufacturer nameplate data for efficiency, or 100%)	%
44/12	=	Carbon to carbon dioxide conversion factor	

[32] GE AES Greenhouse Gas Services, Landfill Gas Methodology, Version 1.0 (July 2007).

Table B.3. CO_2 Electricity Emission Factors

eGRID subregion acronym	eGRID subregion name	Annual output emission rates	
		(lb CO_2/MWh)	(metric ton CO_2/MWh)*
AKGD	ASCC Alaska Grid	1,232.36	0.559
AKMS	ASCC Miscellaneous	498.86	0.226
AZNM	WECC Southwest	1,311.05	0.595
CAMX	WECC California	724.12	0.328
ERCT	ERCOT All	1,324.35	0.601
FRCC	FRCC All	1,318.57	0.598
HIMS	HICC Miscellaneous	1,514.92	0.687
HIOA	HICC Oahu	1,811.98	0.822
MROE	MRO East	1,834.72	0.832
MROW	MRO West	1,821.84	0.826
NEWE	NPCC New England	927.68	0.421
NWPP	WECC Northwest	902.24	0.409
NYCW	NPCC NYC/Westchester	815.45	0.370
NYLI	NPCC Long Island	1,536.80	0.697
NYUP	NPCC Upstate NY	720.80	0.327
RFCE	RFC East	1,139.07	0.517
RFCM	RFC Michigan	1,563.28	0.709
RFCW	RFC West	1,537.82	0.698
RMPA	WECC Rockies	1,883.08	0.854
SPNO	SPP North	1,960.94	0.889
SPSO	SPP South	1,658.14	0.752
SRMV	SERC Mississippi Valley	1,019.74	0.463
SRMW	SERC Midwest	1,830.51	0.830
SRSO	SERC South	1,489.54	0.676
SRTV	SERC Tennessee Valley	1,510.44	0.685
SRVC	SERC Virginia/Carolina	1,134.88	0.515

Source: U.S. EPA eGRID2007, Version 1.1 Year 2005 GHG Annual Output Emission Rates (December 2008).
* Converted from lbs CO_2/ MWh to metric tons CO_2/MWH using conversion factor 1 metric ton = 2,204.62 lbs.

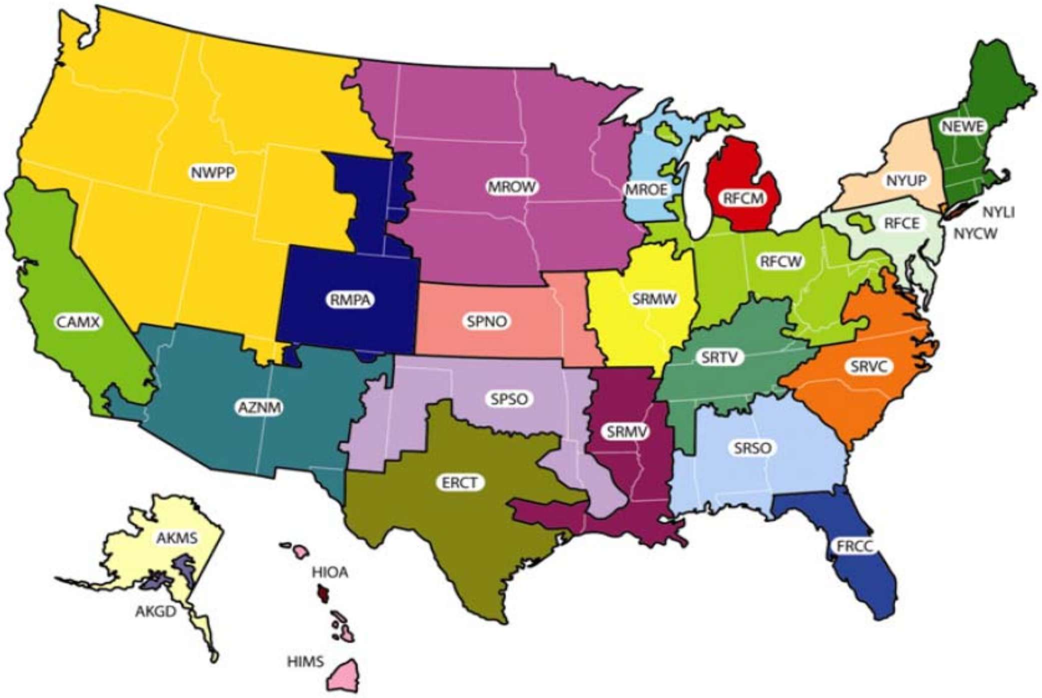

Figure B.1. Map of eGRID2007 Subregions

Appendix C Data Substitution Guidelines

This appendix provides guidance on calculating emission reductions when data integrity has been compromised due to missing data points. No data substitution is permissible for equipment such as thermocouples which monitor the proper functioning of destruction devices. Rather, the methodologies presented below are to be used only for the methane concentration and flow metering parameters, including temperature and pressure data.

The Reserve expects that projects will have continuous, uninterrupted data for the entire verification period. However, the Reserve recognizes that unexpected events or occurrences may result in brief data gaps.

The following data substitution methodology may be used only for flow and methane concentration data gaps that are discrete, limited, non-chronic, and due to unforeseen circumstances. Data substitution can only be applied to methane concentration *or* flow readings, but not both simultaneously. If data is missing for both parameters, no reductions can be credited. The methodology may also be used for missing temperature and pressure data (which is used to adjust flow rate). However, the methodology must be applied to both parameters simultaneously, regardless of if data is available for one or the other. In other words: if either temperature or pressure data is missing, the project developer must use the following methodology to substitute data for both parameters over the same time interval.

Further, substitution may only occur when two other monitored parameters corroborate proper functioning of the destruction device and system operation within normal ranges. These two parameters must be demonstrated as follows:

1. Proper functioning can be evidenced by thermocouple readings for flares, energy output for engines, etc.
2. For methane concentration substitution, flow rates during the data gap must be consistent with normal operation.
3. For flow substitution, methane concentration rates during the data gap must be consistent with normal operations.

If corroborating parameters fail to demonstrate any of these requirements, no substitution may be employed. If the requirements above can be met, the following substitution methodology maybe applied:

Duration of Missing Data	Substitution Methodology
Less than six hours	Use the average of the four hours immediately before and following the outage
Six to 24 hours	Use the 90% lower or upper confidence limit of the 24 hours prior to and after the outage, whichever results in greater conservativeness.
One to seven days	Use the 95% lower or upper confidence limit of the 72 hours prior to and after the outage, whichever results in greater conservativeness.
Greater than one week	No data may be substituted and no credits may be generated

The lower confidence limit should be used for both methane concentration and flow readings, as this will provide the greatest conservativeness.