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Coalbed Methane
OUTREACH PROGRAM

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

Coal Mine Methane Developments in the United States

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COAL MINE METHANE DEVELOPMENTS IN THE UNITED STATES

Contents

Introduction

Methane (CH_4) accounted for 10 percent of all U.S. greenhouse gas (GHG) emissions in 2015, and has a shorter atmospheric life span than carbon dioxide (CO_2). Coal seams often contain significant quantities of methane that are released to the atmosphere from gassy underground mines during coal extraction.

Coal mine methane (CMM) refers to methane from surface or underground coal mines and abandoned underground coal mines that is released to the atmosphere or captured in advance of, during, or following physical coal mining activities. The release of CMM from active and abandoned mining operations is a major type of GHG emission, accounting for about 9 percent of anthropogenic methane emissions.[1]

CMM emissions management is important for several reasons, including enhanced mine safety, mitigation of GHG emissions, and the potential supply of a local clean energy source. The recovery and use of CMM can lead to improved worker safety and mine profitability, as well as reduced GHG emissions. Most CMM projects recover and use methane from coal mine gas drainage systems, which include pre-mine degasification, in-mine horizontal boreholes, and post-mining gob gas recovery. In 2015, nearly 60 percent of all U.S. CMM emissions were released through underground mine ventilation fans. The concentration of ventilation air methane (VAM) is extremely low, typically below 1 percent. This has been a barrier to VAM recovery and destruction/utilization in the past, but recent technological advancements with oxidation equipment and the growth of carbon markets have made it possible to deploy profitable VAM mitigation projects.

Coal mines around the world have recognized that methane is a clean energy resource that can be captured and used productively, with both economic and safety benefits. CMM is used for power generation, natural gas pipeline injection, vehicle fuel, industrial process feed stocks, onsite mine boilers, mine heating, and home heating distribution systems. Upgrading mine degasification systems can often improve gas quality and create favorable project economics.

The United States has been a leader in CMM recovery and use since the 1990s. There are now 15 CMM projects at active U.S. underground mines, as well as 18 abandoned mine methane (AMM) projects that recover methane from 40 abandoned coal mines. U.S. CMM and AMM recovery and use projects reduced methane emissions by about 1.1 billion cubic meters (BCM) in 2015. The first commercial-scale VAM mitigation project, at the Marshall County Mine in West Virginia, has been operational since September 2012. Ventilation air contains dilute concentrations of methane, making it more technically and economically challenging to recover; VAM comprises the largest source of methane emitted from coal mines. This project reduced methane emissions by 17 million cubic meters (MCM) in 2015.

As part of the U.S. Greenhouse Gas Reporting Program (GHGRP), actual data on methane emissions from underground coal mines has been reported to the U.S. Environmental Protection Agency (EPA) each year since 2012. This data has helped inform stakeholders, particularly the underground coal mining industry, of the magnitude of CMM emissions on public and private lands. It also sheds light on the specific sources of methane from active underground coal mines and highlights both VAM and CMM recovery opportunities for the U.S. coal industry.

This document provides an overview of U.S. CMM emissions, U.S. CMM use and destruction projects, federal policies and state incentives for CMM capture and utilization, and CMM emissions data from the

[1] EPA. 2017. Greenhouse Gas Emissions: Overview of Greenhouse Gases. https://www.epa.gov/ghgemissions/overview-greenhouse-gases.

U.S. Greenhouse Gas Reporting Program, Subpart FF. It also discusses other developments, including the emergence of compliance carbon markets.

Overview of CMM Emissions in the United States

The U.S. coal emissions inventory consists of five different sub-source categories:

- Methane released through underground mine ventilation fans (VAM).
- Gas drainage systems at underground coal mines that use vertical and/or horizontal wells (CMM).
- Fugitive emissions from abandoned coal mines (abandoned mine methane or AMM).
- Coal seams exposed to the atmosphere through surface mining (surface mine methane or SMM).
- Post-mine emissions (surface and underground) released in handling and transporting coal after mining.

Figure 1 breaks down each sub-source category by emissions. U.S. coal mines emitted 3,974 million cubic meters (MCM) of methane in 2015.

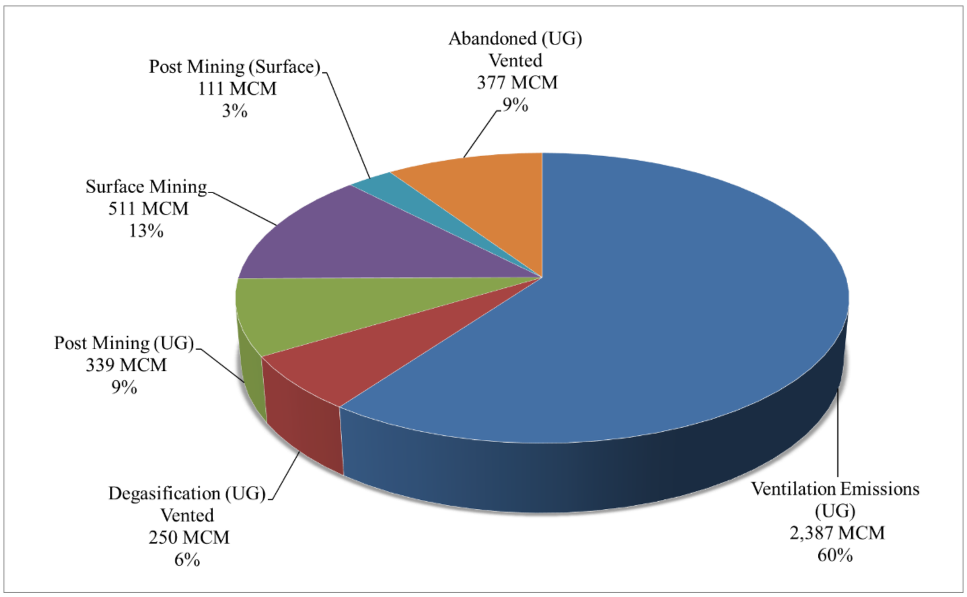

Figure 1. 2015 U.S. CMM Emissions (MCM)[2]

Most emissions from coal mining are attributed to underground operations. In 2015, EPA estimates these operations accounted for about 75 percent (or 2,976 MCM) of methane emissions associated with coal mining. Most of the emissions (2,387 MCM) originate from VAM; post-mining operations and degasification systems are also significant sources. To maintain safe working environments in underground coal mines, particularly gassy mines, use methane degasification systems are used to supplement ventilation fans. In 2015, about 80 percent of the methane from degasification systems was recovered and used.

Emissions from surface coal mining are small compared to emissions from underground coal mining. Coal seams that are mined near the surface contain less in situ methane than deeper coal seams, typically

[2] EPA. 2017. Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2015. https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks.

mined in underground coal mines. Surface mines also contribute to methane emissions from overburden piles and release emissions through uncontrolled combustion and low-temperature oxidation. About 16 percent of 2015 emissions from coal mining were attributable to surface mining and post-surface mining operations.

Figure 2 below shows active underground coal mine production and CMM emissions in the United States from 2000 to 2015. Underground coal production has steadily declined or remained flat since 2000—production in 2015 was 18 percent lower than in 2000. The amount of CMM liberated from underground mines does not closely correlate with coal production: it increased significantly from 2008 to 2011 before falling in 2015 to a level 4 percent lower than in 2000. This trend reflects the closure of less gassy mines and the increased gas contents of the coal being mined in deeper seams. In 2000, U.S. underground coal mines produced about 338 million metric tons of coal and liberated 3.8 BCM of methane. In 2015, underground coal production declined to 278 million metric tons of coal, and underground mines liberated 3.6 BCM of methane. The recovery and use of methane liberated from coal mine degasification systems has averaged 83 percent since 2000. This is due primarily to the deployment of large-scale CMM pipeline injection projects throughout the Appalachian coal basins. The CMM is vented to the atmosphere and accounts for the 250 MCM presented in Figure 1 for degasification emissions.

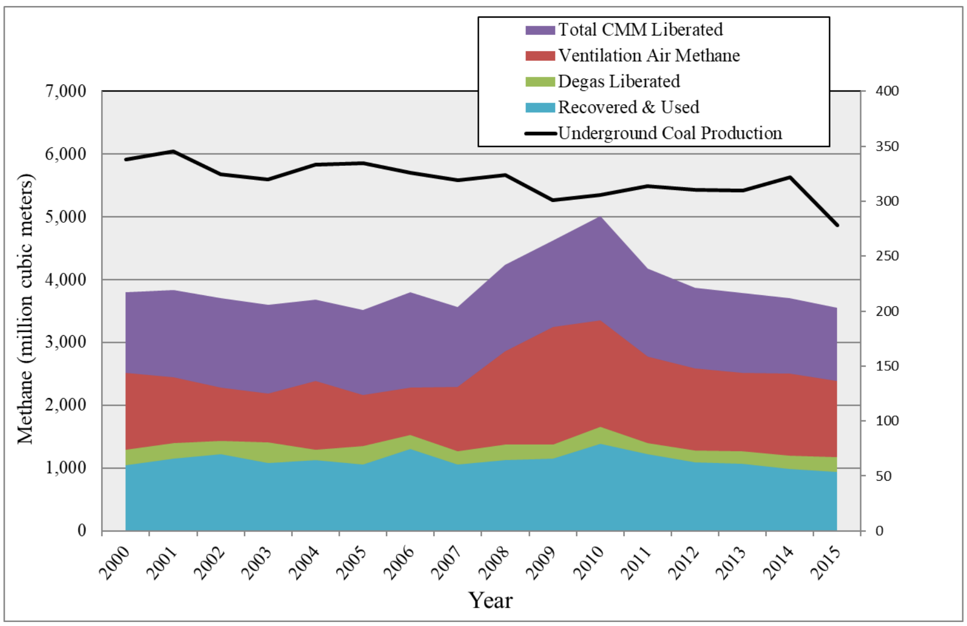

Figure 2. Active Underground Coal Mine Production and CMM Emissions in the United States, 2000–2015

Emissions at U.S. surface coal mines have declined 18 percent from 2000 to 2015, primarily due to lower coal production (16 percent) over that period. The last methane drainage project at a surface mine was decommissioned in 2011.

Many underground coal mines closed in the 1990s, so AMM emissions were near a historical peak in 2000 (see Figure 3). They then declined steadily until 2008, when they leveled off due to an increase in the number of mines closed each year. (Methane emissions can continue for a long time after operations have ceased and a mine has been sealed, due to cracks and fissures in overlying geological layers, boreholes, and vent pipes. Exceptions include mines that are completely flooded, wherein emissions drop to zero after about 15 years.)

Meanwhile, AMM recovery peaked in 2007-2008, following the closure of two large underground coal mines with pre-existing methane recovery projects. Methane vented to the atmosphere from abandoned mines has remained relatively flat since that time, with new abandoned mines offsetting the natural overall decline in AMM emissions.

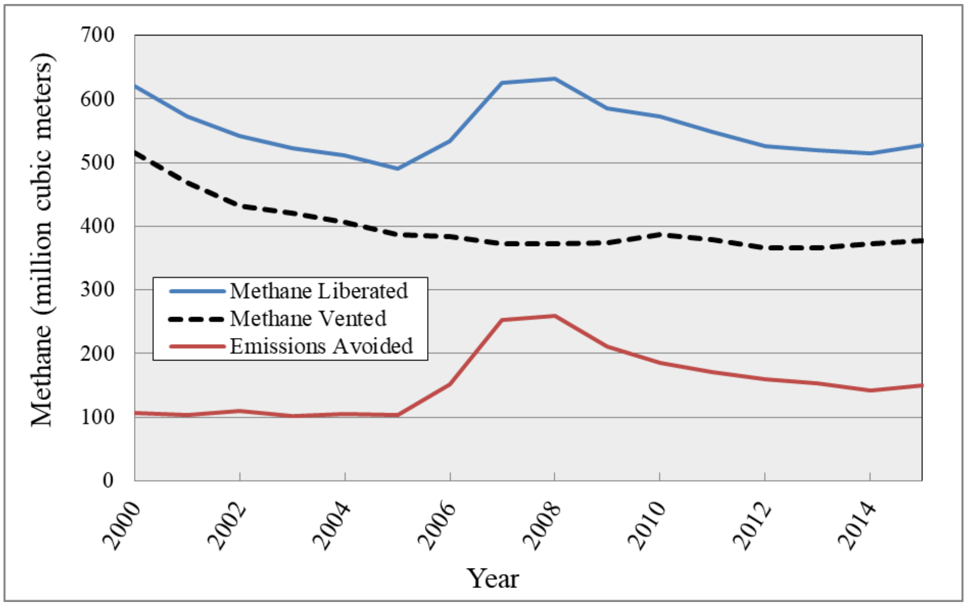

Figure 3. Methane Emissions from Abandoned Mines

Overview of U.S. CMM Utilization and Destruction Projects

As a primary constituent of natural gas, methane can be an important energy source. Efforts to recover and use methane emissions from coal mines can provide economic, environmental, and energy benefits and improve worker safety. CMM recovery and use peaked in 2010 (at an estimated 1,573 MCM) and reached 1,088 MCM in 2015, which is 10 percent below the CMM volume recovered and used in 2000 and 32 percent below the 2010 peak recovery and use volume. CMM utilization and destruction projects involve six project types in the United States: pipeline sales, electric generation, heater, boiler/dryer, flaring, degasification pumps, and VAM oxidation. Several mines have multiple project types.

Injection of CMM and AMM into pipelines is the most common project type. Pipeline projects are feasible for mines with nearby pipelines that can handle the quantity of gas expected to be produced. Methane from a coal mine must also meet pipeline standards to be injected, which may involve upgrading the methane gas to natural gas pipeline specifications.

CMM or AMM can be used as a fuel, generating electricity to meet onsite needs or be sold to utilities. Unlike pipeline injection, CMM for power generation does not require high-quality methane. U.S. projects are typically in the 1- to 3-megawatt range. Electric power generation projects are less common than pipeline projects. The other non-pipeline project located at an active mine uses methane to fuel mine air heaters.

Flaring of CMM or AMM—in open or enclosed systems—converts the methane to carbon dioxide. CMM flare projects have been implemented to reduce methane emissions and thus earn carbon offset credits. Currently, the United States has three flare projects, all working in conjunction with other project destruction devices.

Methane is explosive at concentrations ranging from 5 to 15 percent in air. Federal mine safety regulations require gassy underground coal mines to keep methane concentrations well below the lower explosive limit. For safety, fresh air is circulated through underground coal mines using ventilation systems to dilute methane to levels typically ranging from 0.1 to 1.0 percent. VAM represents about 60 percent of all coal mining emissions in the United States and is vented to the atmosphere at all mines but one. VAM technologies oxidize the methane in mine exhaust air and destroy it before it is released to the atmosphere. The most commonly used VAM technology is thermal oxidation.

In 2015, there were 15 active mines operating 20 methane recovery and use projects in the United States. Thirteen of the projects involve upgrading methane for injection into a commercial pipeline. However, the projects include four types of other end use and methane destruction via flares and thermal oxidizers. Table 1 summarizes the various end uses deployed at the mines. The latest projects to be deployed in the United States were the Elk Creek Mine and Marshall County Mine CMM projects in 2012.

In 2015, there were 18 AMM projects operating at 40 abandoned mines in the United States. Most of these are east of the Mississippi River, in the Central Appalachian, Northern Appalachian, Illinois, and Warrior coal basins; the two western mines are in Colorado and Utah. One project (the Corinth project in southern Illinois) recovers methane from 14 mines that were abandoned between 1926 and 1998.

Table 1. Summary of U.S. Mine Methane Recovery and Destruction Projects

Type of Mine	Number of Mines with Projects	Number of Projects	End Uses					
			Pipeline	Electric Generation	Heater	Boiler/ Dryer	Flare	VAM
Active underground	15	20	13	1	2	1	2	1
Abandoned underground	40	18	15	2	0	0	1	0

CMM Project Profiles

The Elk Creek Coal Mine project, at Oxbow's Elk Creek Mine in Gunnison County, Colorado, was the latest active underground coal mine in the United States to generate electricity from CMM, and the first at a western coal mine. The Elk Creek mine was abandoned in 2016; however, the project transitioned to a multi-mine AMM project that included four adjacent abandoned mines. The 3-megawatt plant continues to operate in conjunction with an enclosed flaring system. In addition to selling electricity to a local utility, the project has generated offset credits in voluntary and compliance carbon markets in the United States.

Elk Creek CMM Electric Power Project

The VAM project at Murray Energy's Marshall County Mine in West Virginia began destroying methane in May 2012 and as of 2017, is the only operating VAM project in the United States. It consists of three regenerative thermal oxidizers that convert methane to carbon dioxide and water vapor. During the start-up phase, the ceramic medium bed in the oxidizer is heated with a propane burner. VAM is then forced through the bed, methane is oxidized, the released heat is recovered by the ceramic bed medium, and the air flow is reversed. The heat recovered from the first cycle heats the incoming VAM and the process repeats. The methane concentration in the VAM ranges between 0.6 and 1.5 percent. The project has also generated offset credits in voluntary and compliance carbon markets in the United States.

Marshall County VAM Project

Market and Policy Incentives for CMM Capture and Utilization

Several voluntary carbon markets in the United States provide opportunities for CMM offset projects to generate carbon credits. Whether a CMM project is eligible for carbon credits depends on specifics such as its start-up date, end use technology (electricity generation vs. pipeline sales), and origin of methane (e.g., active vs. abandoned mines, surface vs. underground mines). In addition, each GHG registry has its own rules governing project eligibility, additionality, and registration. Voluntary carbon markets include the Verified Carbon Standard (VCS), Climate Action Reserve (CAR), and the American Carbon Registry (ACR). During 2015 and 2016, seven of the nine projects, or nearly 80 percent of those registered with voluntary carbon markets, transitioned to the California Air Resources Board (CARB) compliance offset program because of the increased value for the offset credits.

Voluntary Carbon Markets

The CAR, a non-profit registry and trading system based in California, was launched in 2008. The *Coal Mine Methane Project Protocol Version 1.1*, issued on October 26, 2012, covers projects that use CMM for electricity generation and flaring and projects destroying VAM. As of December 2012, CAR had four CMM projects registered, all at active mines: two CMM utilization and flaring projects and two VAM projects. One of the VAM projects was decommissioned in 2013; the other three projects have transitioned to CARB.

The VCS began in 2005 and currently manages a portfolio of programs and initiatives including: VCS Program (allows projects to register and sell carbon credits) and VCS California Offset Project Registry (helps administer the registration of carbon credits for California's cap-and-trade program). VCS follows the Clean Development Mechanism (CDM) methodologies and tools for CMM projects, namely CDM methodology ACM0008. VCS developed a surface mine methane (SMM) protocol in 2009 (VMR0001) and an AMM protocol in 2010 (VMR0002). As of December 2011, VCS had five CMM projects registered: two SMM gas pipeline projects and three AMM gas pipeline projects. Although decommissioned in 2011, the two SMM projects received early action credits from CARB. Two of the AMM projects received early action credits; one of those two has transitioned to CARB (the other expects to transition in 2017). The last AMM project was decommissioned in 2014, but never received early action credits or transitioned to CARB.

The ACR, launched in 1996, was the first private voluntary GHG registry in the United States before becoming an enterprise of Winrock International in 2007. ACR considers methodologies from other GHG program standards that are consistent with the ACR Technical Standard, including CDM, VCS, and CAR.

Acting as an offset program registry for CARB, ACR has accepted CMM projects into its system beginning in 2015. No voluntary CMM projects have been registered in ACR.

Compliance Carbon Markets

Since 2011, CARB has operated a compliance offset program as part of its GHG cap-and-trade regulation. In 2014, CARB adopted the Mine Methane Capture (MMC) Protocol allowing CMM projects other than natural gas pipeline sales to qualify as Compliance Offset Projects. CARB then allows covered entities to purchase and trade these ARB Offset Credits from CMM projects anywhere in the United States. The MMC Protocol has renewed interest in CMM projects, particularly VAM destruction projects and projects that use drained gas for power production, flaring, and liquified natural gas or compressed natural gas production.

As of August 2017, CMM projects have been issued credits for 1.5 million metric tons CO_2e reductions in the CARB offset program, representing 3.4 percent of total compliance offset credits issued by CARB (Table 2).

Table 2. Registered Mine Methane Capture Projects in the CARB Offset Program (as of 2017)[3]

Project Name	Project Type	Location	Credit Type	Credits Issued	Start Date	End Date
Verdeo Marshall County VAM Abatement Project	VAM	WV	Early action	197,411	5/4/2012	10/31/2013
			Compliance	504,705	11/1/2013	12/31/2015
Vamox® Demonstration Project at JWR Shaft No. 4-9		AL	Early action	80,766	3/6/2009	2/28/2013
Elk Creek Coal Mine Methane Destruction and Utilization Project	CMM	CO	Early action	432,609	1/1/2014	12/31/2014
			Compliance	266,263	1/1/2015	1/31/2016
Solvay Chemicals, Inc. Waste Mine Methane Project		WY	Early action	498,654	8/13/2010	12/31/2014
			Compliance	424,076	1/1/2015	12/31/2016
Cambria 33 Abandoned Mine Methane Capture and Use Project	AMM	PA	Early action	107,064	1/1/2011	12/31/2014
Corinth Abandoned Mine Methane Recovery Project		IL	Early action	490,456	1/1/2010	12/31/2014
			Compliance	298,891	1/1/2015	12/31/2016
Baker Mine AMM Project		KY	Compliance	2,236	4/4/2016	10/4/2016
North Antelope Rochelle Coal Mine Project	SMM	WY	Early action	1,072,724	3/28/2006	3/31/2009
Total CARB credits issued for MMC as of August 2017			**Early action**	**2,879,684**	3/6/2009	12/31/2014
			Compliance	**1,496,171**	1/1/2013	12/31/2016
			Total	**4,375,855**		

[3] California Air Resources Board. 2017. ARB Offset Credits Issued. https://www.arb.ca.gov/cc/capandtrade/offsets/issuance/arb_offset_credit_issuance_table.pdf.

Alternative and Renewable Energy Incentives for CMM

CMM is considered an increasingly important alternative or renewable energy resource to help states meet renewable energy portfolio standards (RPS). Many U.S. states have developed RPS that direct electricity providers to generate or obtain minimum percentages of their power from "eligible energy resources" by certain dates. Out of the top 15 coal-producing states in 2015,[4] five—Pennsylvania, Ohio, Utah, Indiana, and Colorado—currently include CMM in their renewable or alternative energy standards.

In those states RPSs, CMM is considered "similar" to landfill gas, in that methane is released over time during industrial-type operations, and efforts to capture and use or destroy CMM are technically similar to measures used to collect and dispose of landfill gas.

Pennsylvania and Ohio each designate CMM as an "alternative" energy resource rather than a "renewable" energy resource. Generally, the term "renewable energy" resources refers to sources such as solar-electric, solar thermal energy, wind power, hydropower, geothermal energy, fuel cells, and certain biomass energy and biologically derived fuels. However, the designation of alternative energy sources varies from state to state and may include sources such as waste coal, demand-side management or energy improvement projects, and solid waste conversion technologies. Where CMM is included as part of a state's renewable or alternative energy portfolio standards, other state-level alternative energy incentives for development can also exist. Table 3 provides a summary of state CMM incentives and complete details regarding states' incentive programs can be found in Appendix A.

Table 3. Summary of State CMM Incentives

State	Definition of CMM	Incentives and Programs
Pennsylvania	CMM is an alternative energy resource	Alternative Energy Portfolio Standard • Alternative energy credits
Ohio	CMM is an advanced energy resource; AMM is a renewable energy resource	Alternative Energy Resource Standard • Renewable energy certificates (RECs) Advanced Energy Program • Forgivable and non-forgivable loans
Colorado	CMM is a renewable energy resource if it is GHG-neutral electricity; determined on a case-by-case basis	Renewable Energy Standard • RECs
Utah	CMM is a renewable energy resource	Renewable Portfolio Standard • RECs
Indiana	CBM (coalbed methane) is defined as an alternative energy source and clean energy resource	Voluntary Clean Energy Portfolio Standard • Incentives to help pay for compliance projects

CMM Data from the U.S. Greenhouse Gas Reporting Program Subpart FF

Greenhouse Gas Reporting Program Overview

In 2009, the U.S. EPA issued the Mandatory Reporting of Greenhouse Gases Rule, which requires reporting of GHG data and other relevant information from large sources and suppliers throughout the United States. Since 2010, the information gathered by the rule has given EPA a better understanding of the

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[4]Alabama, Ohio, Pennsylvania, Illinois, Indiana, West Virginia, Virginia, North Dakota, Kentucky, Texas, Colorado, Wyoming, Utah, Montana, and New Mexico.

relative emissions of specific industries and of individual facilities within those industries. In general, facilities that emit 25,000 metric tons or more per year of GHGs are required to submit annual reports to EPA. In the case of underground coal mines (Subpart FF), facilities that liberate 36.5 million cubic feet of methane per year (17,525 metric tons CO2e (1,033,700 cubic meters of methane) or more per year must report.

The first reporting year for underground coal mines was 2011. Reports are submitted annually by the end of March in the year following the reporting year and become available to the public in October. EPA publishes current year and prior year data through its interactive Facility Level Information on Greenhouse Gases Tool (FLIGHT)[5] and EPA's Envirofacts[6] data portal.

Coal Mine Reporting Requirements

The GHG Reporting Rule requires underground coal mines subject to the rule to report methane liberated through ventilation streams and degasification systems. The mines report the net ventilation and drainage flows along with the portion of that flow that is emitted and the portion recovered for use or flaring. If the recovered methane is combusted without energy recovery (e.g., flared or oxidized), the CO_2 from methane destruction is also reported. Use of methane in an engine or other useful combustion device requires that the facility report CO_2 emissions under the subpart covering combustion devices, if it is a size and type that fits the subpart requirements.

The GHG Reporting Rule allows mines to use one of three approaches to calculating emissions from mine ventilation systems: they may measure flow rates and emission concentrations directly by taking grab samples or using Continuous Emissions Monitoring (CEMS) to calculate total emissions, or they may use the air sampling results from MSHA's quarterly inspections. MSHA regulates in-mine concentrations of ventilation air using well-defined procedures to ensure that the methane is well below explosive levels. Mines can access that data for use in calculating overall emissions. To calculate emissions from degasification systems, mines must use either grab samples or CEMS.

Results of 2011–2016 Data Collection

In 2016, 94 underground coal mines reported to the GHGRP; their emissions totaled 1,559,644 metric tons of methane. A majority of reporting mines (70 percent) that year used quarterly MSHA measurements as the basis of their emissions report rather than their own samples (Table 4). Methane emissions decreased by 5 percent from 2011 to 2016.

Table 4. GHGRP Subpart FF Reporting: 2011 - 2016

	2011	2012	2013	2014	2015	2016
GHGRP Underground Mines Reporting	117	118	131	130	124	94
Active U.S. Underground Mines*	508	488	395	345	305	253
GHGRP Share						
Percent of Underground Coal Mines	23%	24%	33%	38%	41%	37%
Percent of Underground Coal Production	84%	87%	89%	89%	88%	77%

* EIA (2012-2017) Annual Coal Reports 2012-2017. Table 1. Energy Information Administration, U.S. Department of Energy.

[5] https://ghgdata.epa.gov/ghgp/main.do#
[6] https://www3.epa.gov/enviro/

Conclusions

CMM accounts for about 9 percent of total U.S. anthropogenic methane emissions. Managing CMM emissions improves worker safety and mine profitability. Since 2000, the recovery and use of CMM from coal mine degasification systems has ranged from 77 to 88 percent annually. The first VAM recovery and destruction project in the United States started in 2012. California's compliance offset program has provided meaningful incentives for U.S. projects, with most eligible projects transitioning from voluntary GHG registries over the past two years. The anticipated increase in price for offsets and the extension of the program to 2030 might incentivize additional CMM, AMM, and VAM projects in the near future. CMM is also increasingly being considered an important alternative or renewable energy resource by individual states, with eligible projects now located in three states. The Greenhouse Gas Reporting Program provides a rich source of information on methane emissions from underground coal mines.

Appendix A: Overview of State Renewable Energy Incentive Programs

Colorado

Colorado became the first state to adopt an RPS by ballot initiative when voters approved Amendment 37, the "Colorado Renewable Energy Requirement Initiative," to create the state's Renewable Energy Standard (RES) in November 2004. More recently, the passing of SB 13-252 in 2013 added CMM as an eligible energy resource for utility providers. As a requirement under the RES, electricity generated from CMM must also be shown to be greenhouse gas neutral over a five-year period. The RPS requires utilities to generate different percentages of power from eligible energy resources, based on their sector type. By 2020, each sector must generate electricity from eligible energy sources in the following proportions of their retail sales: 30 percent for investor-owned utilities, 20 percent for electric cooperatives serving 100,000 or more meters, 10 percent for electric cooperatives serving fewer than 100,000 meters, and 10 percent for municipal utilities serving more than 40,000 meters.

Utilities comply with the RPS by obtaining and retiring RECs. One REC is issued per one megawatt-hour of electricity generated by a renewable energy source. RECs are good until the end of the fifth calendar year following the year in which it was generated, and a utility can buy, sell, or trade RECs given that it obtains and retires enough RECs to comply with the RES requirements.

Since November 2012, Colorado's Elk Creek Mine Project in Gunnison County is generating 3 megawatts of electricity which is bought by Holy Cross Energy. The project is operated by Vessels Coal Gas, Inc.

Indiana

Indiana passed its Clean Energy Law in May 2011, which established the Clean Energy Portfolio Standard, also known as the Comprehensive Hoosier Option to Incentivize Cleaner Energy (CHOICE) program. Regulated by the Indiana Utility Regulatory Commission (IURC), the program creates incentives for the state's utilities to voluntarily increase the amount of clean energy resources in their electricity portfolios and is open to electricity suppliers approved by the IURC. The voluntary goal set forth by the CHOICE program requires that 10 percent of electricity produced is generated from qualifying clean energy sources by 2025. The Clean Energy Law names 21 clean energy sources qualifying under the standard, including CBM.

Electricity suppliers choosing to participate in CHOICE must apply to and be approved by the IURC, and submit a plan to meet the goals, including a detailed business plan and identification of specific projects and resources, as well as proof of compliance to the program's requirements. Similar to Utah, the state lets utilities meet this target by producing electricity from an eligible form of renewable energy or by purchasing clean energy credits, which are defined as one megawatt-hour of clean energy or 3,412,000 British thermal units (BTU).

Hoosier Energy, an electricity and generating cooperative, constructed a 13-megawatt-hour CBM power generating facility in Sullivan County. This is a first-of-its-kind facility, the only one solely operating on CBM. The project is unique because the methane is collected, processed, and converted to electricity entirely onsite, and began operations in May 2013. The project eliminates approximately 390,000 metric tons CO_2e.

Ohio

Ohio's Alternative Energy Resource Standard (AERS) was created by S.B. 221 in May 2008. The AERS combines renewable energy resources and advanced energy resources into one category, "alternative energy resources." In its current form, the AERS applies to electric utilities and electric service companies serving customers in Ohio and requires utilities to provide 12.5 percent of their retail electricity supply from alternative energy sources by 2026.

In July 2009, legislators amended the original law with Sub H.B. 1, to include methane gas emitted from abandoned coal mines as well as methane from operating coal mines as an alternative energy resource. The law was also amended to include projects with technologies, products, activities, and management practices or strategies that facilitate the generation or use of energy that supports reduced energy consumption or production of clean renewable energy. Thus, CMM pipeline sales projects could qualify under the revised law. In May 2014, S.B. 310 changed the original standards set forth by S.B. 221, by freezing the ramp-up schedule of renewable percentage benchmarks for two years, removing the in-state requirement for renewable energy procurement, and pushing back the final renewable benchmark from 25 percent to 12.5 percent from 2024 to 2026. Ohio was the first state to freeze its multi-year alternative energy ramp-up schedule, but as of January 1, 2017, the AERS was mandatory again. Ohio's House of Representatives voted in March 2017 to turn the AERS into a voluntary standard. The bill now goes to the Ohio Senate, where there is no similar legislation.

AERS compliance is achieved by earning or purchasing qualified renewable energy certificates (RECs), which are good for five years after acquisition. One REC is issued per one megawatt-hour of electricity generated by a renewable energy source. At least 50 percent of the renewable energy requirement must be met by in-state facilities, and the remaining 50 percent can be provided from renewable energy resources shown to be deliverable into the state. Only RECs generated after July 31, 2008, from facilities with a capacity of more than 6 kilowatts may be used for compliance. To qualify under the AERS, an alternative energy and renewable energy facility must have a placed-in-service date of January 1, 1998, or later and must be a member in good standing of the PJM (a regional transmission organization), MISO (the regional electric power market), or other credible tracking system.

CBM Ohio LLC operates an AMM project and is receiving RECs for its methane-to-pipeline sales in Harrison County, Ohio. It is currently managing exploration and production of over 20,000 acres of abandoned coal mines in the state. In 2013, CMM accounted for 1.4 percent of the total REC retirements in the state.

Pennsylvania

Pennsylvania was the first state to define CMM as an alternative energy fuel in its Alternative Energy Portfolio Standard (AEPS), signed into law November 30, 2004. The AEPS does not distinguish between renewable and alternative energy resources; it designates all sources as alternative energy. Eligible technologies include demand-side management, waste coal, CMM, and coal gasification. The AEPS requires each electric distribution company that sells electricity to customers in Pennsylvania to supply 18 percent of its electricity from alternative energy resources by 2021, with at least 8 percent from "Tier I" resources (which includes CMM) by May 31, 2021. The Pennsylvania Public Utility Commission is responsible for carrying out and enforcing the requirements of this law.

Compliance with the AEPS requires alternative energy credits (AECs). One AEC is equal to one megawatt-hour of alternative energy generated and is good for three years from the date it was created. If a utility cannot produce the required AECs for one year, they must make alternative compliance payments to offset the deficit. AECs are similar to traditional renewable energy credits, except that they include both renewable energy resources and Pennsylvania-specific alternative resources. Energy derived from alternative energy sources inside Pennsylvania or within the PJM Service Territory outside the state (the regional transmission group) is eligible to meet the AEPS requirements.

Utah

Utah established a renewable portfolio goal in the "Energy Resource and Carbon Emission Reduction Initiative," enacted in March 2008 (similar to renewable portfolio standards in other states). Under this law, to the extent that it is cost-effective to do so, each electrical corporation and municipal electric utility's retail electric sales must consist of "qualifying electricity" or RECs, equal to 20 percent of its adjusted retail electricity sales. Unlike other state RPS policies, Utah's does not include any interim targets and the first compliance year is 2025.

In early 2010, the Utah legislature passed H.B. 192 "Renewable Energy—Methane Gas," which amended the definition of "renewable energy source" to include "methane gas from an abandoned coal mine or a coal degassing operation associated with a state-approved mine permit" as part of waste gas or waste heat captured or recovered for use as an energy source for an electric generation facility. Initially, the bill included methane gas from abandoned and working coal mines; however, the Senate Transportation and Public Utilities and Technology Committee's proposed Amendment 01 put the term "working" in front of "coal mines" as a potential methane gas resource that might qualify as renewable energy. The Senate and House approved the amendment, effective May 11, 2010.

Utilities may meet targets by producing electricity with an eligible form of renewable energy or by purchasing RECs. RECs issued under the program do not expire.