MillsLegalClinic
StanfordLawSchool

Environmental Law Clinic

Crown Quadrangle
559 Nathan Abbott Way
Stanford, CA 94305-8610
Tel 650 725-8571
Fax 650 723-4426
www.law.stanford.edu

March 29, 2012

Via Electronic Submission

Rachel Tornek
Senior Policy Manager
Climate Action Reserve
523 W. Sixth Street, Suite 428
Los Angeles, CA 90014

Comments on Coal Mine Methane Project Protocol Version 2.0

Dear Ms. Tornek:

The Environmental Law Clinic, part of the Mills Legal Clinic at Stanford Law School, submits these comments to the Climate Action Reserve (the "Reserve") on behalf of Dr. Michael Wara, Associate Professor at Stanford Law School, regarding the Coal Mine Methane Project Protocol, Version 2.0 for Public Comment (the "Protocol").

We appreciate the opportunity to share our perspective on the updated Protocol, and hope our views will contribute to the development of high-quality offset protocols. We would also like to acknowledge the detailed work that has gone into preparing the Protocol by both CAR Staff and the CMM working group. The result is both thorough and fully transparent.

Although the Protocol is generally robust in our opinion, we hope to (1) raise some potential concerns associated with the interaction between the Protocol and the Clean Air Act, and (2) discuss our reservations about the performance standard test with respect to on-site use of methane.

1. **Regulatory Conflicts. The Protocol has the potential to undermine implementation of Clean Air Act regulations for coal mine methane emissions. This issue requires high-level policy discussion that is not part of the Protocol documentation to date.**

As a preliminary matter, we want to highlight a potential conflict the Protocol might create with implementation of stationary source controls on greenhouse gas ("GHG") emissions under the Clean Air Act ("CAA"). We believe this is an issue the Reserve should consider in more detail, especially if the Reserve intends to submit the Protocol to the California Air Resources Board for approval as a compliance-grade protocol for the California carbon market.

As the Protocol notes, EPA has begun regulating GHG emissions from stationary sources under the CAA. Under the legal requirements test for the Protocol, any EPA or CAA requirements for controlling methane would immediately become a part of a project's baseline calculation, and thus not eligible for offset credits.[1] With no existing regulations that force destruction or capture of methane (outside of mine safety rules), the Protocol suggests that the possibility of future regulation is simply one risk factor that projects will have to consider.

[1] Protocol § 3.4.1.1.

This view oversimplifies the applicable Clean Air Act provisions and neglects several key issues, which we discuss below. These issues have potentially significant implications for this Protocol or any other involving a large stationary source of GHGs, both for the Reserve and the California Air Resources Board. As a result, we believe further high-level discussion is required to ensure that the Protocol does not create actual unintended conflicts—or even the appearance of unintended conflicts—with EPA or the Clean Air Act.

Indeed, these sorts of interactions are increasingly likely in a fragmented climate policy landscape, and the Reserve is well positioned to be a leader in developing carefully considered climate strategies that minimize potential conflicts with other regulatory systems.

1.1. Because BACT determinations are made by state permitting agencies, the Protocol could undermine effective implementation of CAA requirements by creating political pressure to weaken BACT standards outside of California.

We are concerned that the Protocol has the potential to undermine or weaken implementation of CAA regulations by creating an incentive for state regulators to weaken BACT determinations for controlling coal mine methane emissions. EPA's recent Tailoring Rule requires certain new facilities or major modifications of existing facilities to obtain a Prevention of Significant Deterioration ("PSD") permit, for which state permitting agencies must determine and apply the best available control technology ("BACT").[2] In particular, major modifications of existing facilities, including coal mines, that result in increased emissions of at least 75,000 tons per year of CO_2e are required to obtain PSD permits.[3]

Although EPA sets the basic contours of the PSD program, application of BACT is left to the states. In *ADEC v. EPA*, the Supreme Court decided that EPA's ability to challenge state BACT determinations is limited to when the state's determination is "not based on a reasoned analysis."[4] This decision gives state permitting agencies wide discretion in determining BACT, subject only to procedural review from EPA.

Because states have effective control over BACT determination, those with coal mine projects seeking offset credits under this Protocol will face additional political pressure to set BACT at levels that create headroom for offset creation. Strict BACT determinations would reduce or eliminate income from offsets, and thus state regulators could face pressure from offset project owners and developers to keep BACT determinations low. Further, state regulators will be aware, or will be made aware by the regulated sources, that in the event they set BACT less stringently, emissions reductions will nevertheless occur because of offsets. Under the *ADEC* standard, EPA would have limited options to challenge any state determinations it perceived as weak. Should this situation arise, the effect of the Protocol would be to unintentionally weaken or undermine implementation of the Clean Air Act.[5]

---

2 *See generally* Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, 75 Fed. Reg. 31514 (June 3, 2010).

3 *Id.* at 31516.

4 *Alaska Dep't Envtl. Conservation v. Envtl. Prot. Agency*, 540 U.S. 461, 490 (2004) (citations omitted).

5 We note that exactly this situation has allegedly occurred under the CDM, where national regulators weakened standards for large landfills in order to create headroom for the creation of CERs under CDM landfill methane protocols. *See* Christiana Figueres, *Sectoral CDM: Opening the CDM to the yet*

Even if the income generated from Protocol projects has no influence on state regulators' BACT determinations, the Protocol could nevertheless create the appearance of influence. This might occur if states make widely divergent BACT determinations. If some states apply strict BACT determinations, while others apply weak determinations, the Protocol could be seen as subsidizing the disparate outcome, as Protocol projects would presumably cluster in states with the most lax permitting agencies. It may be possible to create a "race to the top" in the Protocol's legal requirements test by adopting a threshold from the strictest BACT determinations. But without knowing how states will make BACT determinations, and in what form, it is difficult to imagine writing such a provision into the Protocol at this stage of the CAA regulations.

While these concerns are only hypothetical at this point, we believe the Reserve should have a broader discussion about the unintended consequences its offsets protocols may have in sectors where impending state or federal regulations complicate the application of offset protocol design. We also believe that CAR should develop a plan, set down explicitly in the protocol, to address these concerns once we know more about how states will proceed with BACT determinations for CMM. We would propose that once 5 BACT determinations have been concluded, CAR review them and consider revising Section 3 of the Protocol as appropriate.

1.2. Determining what constitutes a "major modification" of an existing coal mine under EPA's Tailoring Rule is an open legal question. The Protocol does not offer any guidance on how project developers would bear the risks associated with litigation on this issue.

The Protocol does not sufficiently anticipate the possibility that PSD permits might be required for existing coal mines, even without new regulations from EPA. To the best of our knowledge, there are no cases or regulations clarifying what constitutes a "major modification" of an existing coal mine for the purposes of the CAA. If certain common activities—for example, beginning work on a new section of a coal seam within an existing large mine—are determined to be major modifications, then the Tailoring Rule would apply, and PSD permits would be required for mines creating new emissions above the established threshold.

The Protocol would benefit from a fuller discussion of how these risks would be distributed, especially with the prospect of lengthy litigation or subsequent regulatory developments. We have several questions about what the timing of these kinds of changes would imply for calculating additionality under the Protocol:

- Does the Protocol's legal requirements test apply at the time the legal requirement is identified (*i.e.*, when a court or administrative agency finds that a PSD permit is required) or when the actual legal requirement is specified (*i.e.*, when a state regulator identifies BACT for a particular mine project)?

- If litigation produces a determination that a major modification took place, does the Protocol's legal requirements test adopt BACT requirements retroactively, from the date of the legal decision, or from the date of the subsequent issuance of a permit? Does it matter whether the question litigated was a new issue that was fairly disputed by both sides?

Unrealized Goal of Sustainable Development, 2 MCGILL INT. JOURNAL OF SUSTAINABLE DEVELOPMENT LAW AND POLICY 1, 12 (2006).

- If litigation or a new regulation defines a threshold for major modifications, must all applicable projects immediately adopt BACT requirements as part of the legal requirements test, or are those requirements not binding for the purposes of the Protocol during a legally valid gap (*e.g.*, a temporary window for securing permits)?

1.3. Air pollution from coal mines is not yet subject to new source performance standards under Section 111 of the CAA, the future implementation of which would set a floor for state determination of BACT for PSD permits. The Reserve should monitor developments on this front.

EPA has not yet exercised its authority to create performance standards for coal mine methane emissions controls under Section 111 of the CAA, but faces pressure to do so. These performance standards would apply to all new and existing coal mines. In June 2010, a group of environmental organizations petitioned EPA to list coal mines as a category of stationary sources subject to performance standards for GHGs, including coal mine methane as a particular source of concern. EPA has not acted on this petition. As a result, the environmental groups sued, seeking to compel EPA to grant or deny the petition.[6]

The outcome of this ongoing litigation matters, as EPA's performance standard authority extends to both new and existing emissions sources.[7] Moreover, state determinations of BACT cannot allow emissions higher than levels determined under Section 111 of the CAA.[8] That is, state BACT determinations are constrained to be no weaker than a performance standard set by EPA under its § 111 authority. Therefore, we believe the Reserve should pay close attention to this issue going forward, as it may either exacerbate or relieve some of the other CAA interactions described above.

If and when EPA sets a § 111 performance standard, it will act to significantly shift the baseline emissions for all participating or potential projects under the CMM protocol. The concerns raised above in section 1.2 also apply here. Furthermore, the Reserve should plan on this performance standard being subject to lengthy litigation. How will project registrations be treated and offsets generated by registered projects during this period of uncertainty be credited?

2. Additionality. The Protocol's Performance Standard Test does not adequately address the possibility that drainage systems have the economically viable option to inject methane into a commercial pipeline, but choose instead to use or flare methane onsite.

We are concerned that some offset projects may be able to switch back and forth between earning offsets under this Protocol and selling methane into a pipeline network. If permitted, this temporal "stacking" would undermine the additionality of the Protocol, and runs counter to principles articulated in other Reserve protocols.[9]

---

6 *WildEearth Guardians, et al., v. U.S. Envtl. Prot. Agency and Lisa P. Jackson*, No. 1:11-cv-02064-RJL (D.D.C.) (complaint filed Nov. 17, 2011).

7 42 U.S.C. § 7411(b) (new sources); 42 U.S.C. § 7411(d) (existing sources); *see also* Georgetown Climate Center, Issue Brief: EPA's Forthcoming Performance Standards for Regualting Greenhouse Gas Pollution from Power Plants (Clean Air Act Section 111).

8 42 U.S.C. § 7479(3).

9 *See, e.g.,* Climate Action Reserve, Rice Cultivation Project Protocol, Version 1.0 § 3.5.3 (prohibiting stacking of ecosystem service payment systems in addition to earning carbon offsets for the same mitigation activities).

Our concerns arise because the Protocol's eligibility rules allow a drainage system to qualify for offsets by flaring or otherwise using methane, even if selling methane to a pipeline is commercially viable. In other words, the eligibility rules do not include an analysis of the economic viability of injecting methane into a pipeline network. Drainage projects pass the performance standard test simply if they destroy methane "through any end-use management option other than injection into a natural gas pipeline."[10] Remaining eligibility rules require only that that project start dates be no more than three months after the drainage system begins commencing destruction of methane.[11]

Under these rules, a drainage system that injects methane into a pipeline would not appear to qualify for offsets if the project developer decides to build a flare or other end-use management application to replace pipeline exports. Assuming the switch happens after three months of injection, it would appear to violate the eligibility rule on timing. However, the eligibility rules allow for multiple drainage systems to exist at a single coal mine, raising the prospect that as new boreholes are drilled as the mine face advances, the mine operator could elect to either create offsets by flaring or sell pipeline gas from new drainage wells.

We would appreciate the Reserve confirming this matter, and suggest further that there is no valid reason to view a project at a mine that has ever injected gas into a pipeline as additional.

Unfortunately, nothing in the protocol rules precludes the reverse ordering: a project that could economically inject methane into a pipeline might choose instead to pursue an on-site activity and earn offset credits. So long as the drainage system does not inject methane into a pipeline network, it is assumed to be additional under the performance standard test.

That assumption is flawed, however, under a variety of plausible economic conditions. Project developers might instead see the Protocol rule structure as giving them the chance to bet long on carbon prices, with a backstop option to sell methane into a pipeline network if carbon prices do not rise as expected. Indeed, the rational project developer considering pipeline sales would be wise to consider whether or not a carbon offset provides a higher value hedge against low gas prices, as Figure 1 demonstrates.

---

10 Protocol § 3.4.2 (based on the analysis in Protocol Appendix A).

11 *Id.* § 3.2.

Figure 1: Value of Offset Minus Value of Pipeline Sales (\$ per metric ton CH_4)[12]

		CO2 price (\$/tCO2-eq.) 5	15	25	50	Value of natural gas sales
Natural gas price (\$/mmBTU)	2.5	\$ (40.58)	\$ 141.92	\$ 324.42	\$ 780.67	\$ 131.83
	3.5	\$ (93.31)	\$ 89.19	\$ 271.69	\$ 727.94	\$ 184.56
	4.5	\$ (146.05)	\$ 36.45	\$ 218.95	\$ 675.20	\$ 237.30
	5.5	\$ (198.78)	\$ (16.28)	\$ 166.22	\$ 622.47	\$ 290.03
	6.5	\$ (251.51)	\$ (69.01)	\$ 113.49	\$ 569.74	\$ 342.76
	7.5	\$ (304.24)	\$ (121.74)	\$ 60.76	\$ 517.01	\$ 395.49
Value of carbon offsets		\$ 91.25	\$ 273.75	\$ 456.25	\$ 912.50	

Each cell in the main table of Figure 1 shows the difference between the value of the carbon offset derived from flaring methane and the value of selling that methane into a pipeline, for a range of natural gas and carbon prices, per metric ton of CH_4. Positive numbers are highlighted and indicate that for the prices applicable in that cell, the carbon offset is more valuable than the direct sale of methane. Thus, under these conditions, a project developer will prefer to generate offset credits rather than sell captured methane into the pipeline network.

For context, the U.S. Energy Information Administration reports that average wellhead natural gas prices in December 2011 were \$3.06 per mmBTU; prices since 2000 have generally ranged from \$2.5 to \$7.5 per mmBTU, with a few higher spikes.[13] A carbon price of \$5/tCO_2e is a reasonable approximation of the voluntary carbon market, whereas estimates of California's compliance costs are bounded by the remaining prices shown here.

We note that at current forward delivery prices for CCAs (\$14.80 for Dec 2013 delivery),[14] current compliance grade carbon prices would tend to push a coal mine to orchestrate a switch to selling offsets from selling pipeline gas.

The net effect of these incentives is to undermine a key assumption in the Protocol's additionality calculations. By defining the performance standard test for drainage systems as any control technology that does not involve pipeline injection, the Protocol implies that pipeline sales are already economically viable and that all projects not injecting into pipelines do not find it viable to do so.[15] The calculations presented in Figure 1 contradict this assumption and demonstrate that a

---

12 Source: authors' calculations using flaring as an example offset project. Assumptions: 52.73 mmBTU per tCH_4 and 18.25 tCO_2e avoided per tCH_4 destroyed (using GWP and "r" values from Protocol equations 5.5 and 5.9, respectively); prices as shown in chart.

13 Energy Information Adminstration, U.S. Natural Gas Wellhead Price (March 25, 2012), available at: http://www.eia.gov/dnav/ng/hist/n9190us3M.htm. EIA reports December 2011 prices were \$3.14 per thousand cubic feet of natural gas. At 1.025 mmBTU per thousand cubic feet of natural gas, this price is equivalent to \$3.06 per mmBTU.

14 *See* PointCarbon, Carbon Markets North America, 23 March 2012, *at* 2.

15 Protocol Appendix A draws erroneous conclusions to support the proposition that drainage systems using non-pipeline control technologies are always additional. Specifically, Appendix A concludes that the paucity of non-pipteline control technologies reflects their being uneconomic generally, rather than being less economic than pipeline injection. According to Appendix A, only four of twelve drainage systems that do not have a pipeline interconnection employ an alternative mitigation technology. Of these four

rational project developer might prefer to pursue carbon offsets above pipeline sales, with the option to exit the Protocol and sell methane into a pipeline if relative carbon and natural gas prices do not justify the pursuit of offset credits. Indeed, the rational project developer might well prefer to view the Protocol as a hedge against low natural gas prices.

This situation is problematic and undermines the actually additionality of the Protocol. We recommend the Reserve revise the Protocol to prohibit switching from offset credits to pipeline sales, and vice versa.

Our understanding of VAM mitigation technologies is that no rational project developer would seek to invest in the capability to convert ventilation air (less than 1% methane) into pipeline quality gas (90-95% methane).[16] This investment would be necessary to create the option for temporal stacking described above. Thus, our concern applies only to drainage systems.

Sincerely yours,

ENVIRONMENTAL LAW CLINIC
Mills Legal Clinic at Stanford Law School

Danny Cullenward, Certified Law Student
Deborah A. Sivas, Clinic Director and Supervising Attorney

On behalf of: Dr. Michael Wara
Associate Professor, Stanford Law School
Research Fellow, Freeman Spogli Institute for International Studies
Stanford University

We thank Anne Johnson for her valuable research assistance on the Clean Air Act.

---

projects, two are at mines that also have pipeline injections; the analysis excludes these two projects, and focuses only on the two remaining projects that use methane at mines where no pipeline interconnection is present.

On this basis, Appendix A concludes that "on-site end use projects are uncommon even at mines that do not sell their [methane] to pipelines . . . this finding suggests that such project types are generally uneconomic under current conditions, rather than simply less economic than pipeline sales projects." To the extent two drainage projects permit any valid basis for establishing *ex ante* additionality criteria, a more appropriate conclusion would be that the data cannot rule out the alternative hypothesis that pipeline injection is generally more economic than alternative mitigation measures. The difference matters because the first erroneous conclusion supports the Protocol's additionality criterion (which Figure 1 contradicts), whereas the second conclusion is consistent with both the data in Appendix A and the calculations in Figure 1.

[16] C. Özgen Karacan et al., *Coal mine methane: A review of capture and utilization practices with benefits to mining safety and to greenhouse gas reduction*, 86 INTERNATIONAL JOUNRAL OF COAL GEOLOGY 121, 147 (2011) (reviewing VAM characteristics and typical pipeline injection standards), *available at:* http://www.epa.gov/cmop/docs/cmm-paper-2011.pdf.