WEST ELK MINE
E-SEAM GAS ECONOMIC EVALUATION REPORT

Mountain Coal Company LLC

September 24, 2009

United States Department of the Interior

OFFICE OF THE SOLICITOR
Rocky Mountain Region
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October 1, 2009

Edward B. Zukoski
Earthjustice
1400 Glenarm Place #300
Denver, CO 80202

VIA FEDERAL EXPRESS

Re: West Elk Mine E-Seam Gas Economic Evaluation Report

Dear Ted:

Enclosed please find a copy of the non-proprietary portion of Mountain Coal Company LLC's West Elk Mine E-Seam Gas Economic Evaluation Report. As part of our ongoing settlement negotiations, you agreed to keep this report confidential for a period of 45 days from receipt. We appreciate your cooperation in this matter.

If you have any questions, please feel free to call me at (303) 231-5353 ext. 552.

Regards,

Kristen Guerriero

Kristen Guerriero

Enclosure

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TABLE OF CONTENTS

Page

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INTRODUCTION

On March 25, 2009, Lynn E. Rust, Deputy State Director, Energy, Lands and Minerals, Colorado State Office of the United States Bureau of Land Management ("BLM") requested that Mountain Coal Company, LLC ("Mountain Coal") prepare an economic evaluation report ("R2P2 Report") to supplement the existing Resource Recovery and Protection Plan ("R2P2"), submitted pursuant 43 C.F.R. § 3482.1 for Mountain Coal's West Elk Mine in Colorado, to address coal mine methane management options at the mine ("BLM Letter"). *See* **Exhibit A**. The BLM Letter requested submission of the R2P2 Report within six months. This R2P2 Report is submitted in response to the BLM Letter.

I.
BACKGROUND

A. Coal Mine Methane Characteristics

The association of methane and coal is described in the United States Supreme Court Case *Amoco Production Company v. Southern Ute Indian Tribe*, 526 U.S. 865 (1999), as follows:

> Coal is a heterogeneous, noncrystalline sedimentary rock composed primarily of carbonaceous materials. See, *e. g.*, Gorbaty & Larsen, Coal Structure and Reactivity, in 3 Encyclopedia of Physical Science and Technology 437 (R. Meyers ed., 2d ed. 1992). It is formed over millions of years from decaying plant material that settles on the bottom of swamps and is converted by microbiological processes into peat. Van Krevelen, Coal 90 (3d ed. 1993). Over time, the resulting peat beds are buried by sedimentary deposits. *Id.,* at 91. As the beds sink deeper and deeper into the earth's crust, the peat is transformed by chemical reactions which increase the carbon content of the fossilized plant material. *Id.* The process in which peat transforms into coal is referred to as coalification. *Id.*
>
> The coalification process generates methane and other gases. R. Rogers, Coalbed Methane: Principles and Practice 148 (1994). Because coal is porous, some of that gas is retained in the coal. [Gas] exists in the coal in three basic states: as free gas; as gas dissolved in the water in coal; and as gas "adsorped" on the solid surface of the coal, that is, held to the surface by weak forces called van der Waals forces. *Id.,* at 16—17, 117. These are the same three states or conditions in which gas is stored in other rock formations. Because of the large surface area of coal pores, however, a

> much higher proportion of the gas is adsorped on the surface of coal than is adsorped in other rock. *Id.*, at 16—17. When pressure on the coalbed is decreased, the gas in the coal formation escapes. As a result, [gas] is released from coal as the coal is mined and brought to the surface.

Southern Ute, 526 U.S. at 872-73.

When gas is released by underground mining activities, it is considered "Coal Mine Methane" ("CMM"). CMM consists primarily of methane (CH_4), with a much lesser amount of ethane (C_2H_6), mixed with oxygen, nitrogen, and carbon dioxide. The gas occurs naturally in coal seams and in the sedimentary rock overlying coal seams. During the course of mining, coal mine methane is released as the coal is mined and as overlying rock strata fracture through subsidence. Coal mine methane is a significant safety hazard to miners. It is toxic and at air concentrations of between 5% and 15% by volume, methane is explosive.

B. <u>Use of Coal Mine Methane</u>

The *Southern Ute* decision established two key principles related to the use of CMM in the context of federal coal resources such as those found at the West Elk Mine. First, the Court held that when the federal Coal Lands Acts of 1909 and 1910 were enacted, Congress was aware of and had established the need to vent CMM for coal mine safety where it was necessary and reasonable to do so. *Id.* at 879. Second, the Court concluded that Congress had not viewed CMM as a valuable fuel resource at the time, and had narrowly reserved federal coal rights. As a result the reservation of the coal did not encompass CMM gas. *Id.*

Although *Southern Ute* by its terms relates solely to the reservation of coal under lands sold to private parties, the BLM concluded from the decision that the appropriate manner in which to productively develop CMM was through a separate gas lease issued under the Mineral Leasing Act. *See Vessels Coal Gas, Inc.* 175 IBLA 8, at 2-3 (2009) (summarizing BLM policies on coalbed methane development). As early as 2001, Mountain Coal submitted expressions of interest for lands overlying the West Elk Mine for leasing for the purpose of exploring productive uses for CMM vented from the mine. The lease nominations were never acted upon, largely owing to the long running dispute regarding the scope and application of the "Roadless Rule" to United States Forest Service administered lands such as those overlying the West Elk Mine.

In 2007, the BLM attempted to lease CMM under the oil and gas provisions of the Mineral Leasing Act at the Aberdeen Coal Mine in Utah. *Vessels,* at 3-7. The resulting lease was challenged by Vessels Coal Gas. On June 30, 2008, the IBLA invalidated the leases, concluding that CMM is not a gas "deposit" within the meaning of the Mineral Leasing Act, and therefore not subject to leasing under a gas lease. *Vessels,* at 12-13. The *Vessels* decision expressly took no position on the potential for BLM to manage CMM under an alternative authority. The IBLA did direct that once the BLM determined an authority under which to manage CMM, "it will be incumbent on BLM to address such issues in advance and with its coal lessees under approved R2P2s." *Id.* at 14.

The BLM considered its options during the Summer and Fall of 2008. On October 28, 2008, at the 2008 U.S. Coalbed Methane Conference in Pittsburgh, Pennsylvania, the BLM explained its anticipated approach to CMM management in light of the *Vessels* decision. The BLM concluded that in general:

- BLM regulatory authority is limited to lands where the U.S. owns both the coal and the gas estates;
- BLM must consider any pre-existing and conflicting lease rights.
- Under the *Vessels* decision, BLM may only authorize the coal lessee to capture methane released as part of coal mining.

The BLM further determined that the appropriate approach to authorize CMM development was:

- Bilateral agreement between BLM and the coal lessee to amend the coal lease;
- To authorize capture of methane if:
  - (1) economically feasible, and
  - (2) does not jeopardize the safety and health of miners; and
- All applicable laws and regulations will apply.

Exhibit B, at 19, 21. In that same presentation, the BLM announced that its first application of the new policy would be at the West Elk Mine. *Id.* at 22.

C. <u>Coal Lease Addenda</u>

During late 2008, and early 2009, the BLM and Mountain Coal negotiated amendments to West Elk's coal leases related to mining the "E Seam" coal at West Elk, for which mining approvals had been granted on July 31, 2008. Amendments to three coal leases pertinent to the E Seam (C-1362, COC-56447, and COC-67232) ("Coal Leases") were executed on January 14, 2009. In each case the following authority was granted:

> Sec. 3. Notwithstanding the language in Section 2 of this lease and subject to the terms and conditions below, lessee is authorized to drill for, extract, remove, develop, produce and capture for use or sale any or all of the coal mine methane from the above described lands that it would otherwise be required to vent or discharge for safety purposes by applicable laws and regulations. For purposes of this lease, "coal

> mine methane" means any combustible gas located in, over, under, or adjacent to the coal resources subject to this lease, that will or may infiltrate underground mining operations.
>
> Sec. 4. Notwithstanding any other provision of this lease, nothing herein shall, nor shall it be interpreted to, waive, alter or amend lessee's right to vent, discharge or otherwise dispose of coal mine methane as necessary for mine safety or to mine the coal deposits consistent with permitted underground mining operations and federal and state law and regulation. Lessee shall not be obligated or required to capture for use or sale coal mine methane that would otherwise be vented or discharged if the capture of coal mine methane, independent of activities related to mining coal, is not economically feasible or if the coal mine methane must be vented in order to abate the potential hazard to the health or safety of the coal mines or coal mining activities. In the event of a dispute between lessor and lessee as to the economic or other feasibility of capturing for use or sale the coal mine methane, lessor's remedy as a prevailing party shall be limited to recovery of compensatory royalties on coal mine methane not captured for use or sale by lessee. Lessee shall have the right to continue all mining activities under this lease, including venting coal mine methane, pending resolution of any dispute regarding the application of the terms of Sections 3 and 4.

Exhibit C.

A critical feature of the lease addenda is that each of these granted Mountain Coal the *authority* to capture or otherwise manage CMM, but did not *require* Mountain Coal to capture CMM. The requirement to evaluate the feasibility of capturing CMM was concurrently imposed in two mining plan approvals.

D. <u>Mining Plan Approvals</u>

Two permit and mining plan approvals were required to mine the E Seam, identified as TR-111 and PR-14. TR-111 relates to the first panel of coal to be mined in the E Seam (E-1), and PR-14 relates to the remaining E Seam panels. (E-2 to E-12).[1] TR-111 related to federal coal leases C-1362 and COC-56447, and was approved on July 31, 2008. **Exhibit D**. PR-14 related to federal coal leases C-1362 and COC-67232, and was approved on January 15, 2009. **Exhibit E**.

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[1] Although the permitting documents were similar, the Colorado Division of Mines, Reclamation, and Safety concluded that permitting of the second set of panels was best processed as a "Permit Revision" ("PR"), rather than a "Technical Revision" ("TR").

TR-111 contained the following special condition:

> If, under a bilateral agreement with Federal leasee, the Bureau of Land Management amends Federal leases C-1362 and COC-56477 to authorize the capture of coalbed gas that would otherwise be vented as required by the Mine Safety and Health Administration, the operator shall capture the vented coalbed gas if such capture is economically feasible and does not jeopardize the safety or health of the miners. The capture operations must comply with the terms of the amended leases and all applicable laws and regulations, including those administered by the U.S. Forest Service and the Colorado State program.

See **Exhibit D**. PR-14 incorporated slightly revised language:

> (8) Once all permits and other necessary clearances are obtained, the operator shall capture the vented coalbed gas if such capture is economically feasible and does not jeopardize the safety or health of the miners. The capture operations must comply with the terms of the amended leases and all applicable laws and regulations, including those administered by the U.S. Forest Service and the Colorado State program.

See **Exhibit E**.

The combination of the leases and approvals thus created an authorization to manage CMM, and a requirement to manage CMM, subject to economic feasibility and safety standards, as well as whatever other constraints might result from other applicable laws and regulations.

The next, and final, directive from the BLM relevant to this R2P2 Report was the March 25, 2009 BLM Letter.

E. <u>BLM Letter</u>

The BLM Letter directed Mountain Coal to undertake several different analyses related to CMM and Ventilation Air Methane ("VAM") development for E Seam panels E-1 to E-12. Each of these is listed below, along with the Section of this R2P2 Report that most directly addresses the request (although it should be noted that data, assumptions, and conclusions from certain sections affect the analyses in multiple other sections):

- An analysis of the costs associated with collection of vented CMM from holes developed specifically for the purpose of venting of the CMM for safety purposes.

  The requested analysis is provided in Section III of this R2P2 Report

- An analysis of the costs associated with collection/capture of VAM.

The requested analysis is provided in Section V of this R2P2 Report.

- All costs associated with the collection of the CMM that is [sic] above and beyond what is associated with normal venting operations including but not limited to construction of gathering systems, roads, pipelines, etc.

  These costs are presented in Section III of this R2P2 Report.

- All costs associated with putting the CMM or VAM in a marketable condition including compressing and refining systems and transportation to the point of sale.

  These costs are presented in Sections III and V of this R2P2 Report.

- An analysis of the costs associated with collection and use of CMM or VAM.

  These costs are presented in Sections III and V of this R2P2 Report.

- All projected revenue from the sale of CMM or VAM.

  These revenues are presented in Sections III and V of this R2P2 Report.

- Any carbon credit offsets acquired as a result of the capture/sale of the CMM or VAM must be taken into account.

  The availability and considerations related to carbon credits are discussed in Section IV of this R2P2 Report.

- The economic evaluation will include a reasonable cost of capital and employ commonly used analytical tools used in project finance, such as a discounted cash flow analysis.

  These and other applicable standards are discussed in Section IIIA of this R2P2 Report.

The BLM Letter further directed Mountain Coal to propose the equipment and technology to be used in monitoring CMM and VAM production. The proposed equipment is described in Section VI of this R2P2 Report.

In addition to the analyses required by the BLM Letter, Section II of this R2P2 Report explains the process Mountain Coal employed for identifying viable CMM and VAM use options, the selection of outside contractors to assist in technical evaluations, and the identification and segregation of confidential business information.

II.
PROCESS

A. Identify Alternatives

The first step in the R2P2 evaluation was to identify potential uses and technologies for managing the West Elk E Seam CMM. A reasonable starting point for this exercise was the alternatives identified in the Forest Service Environmental Impact Statement ("EIS") for the E Seam. The EIS identified two principal alternatives – (1) flaring, and (2) processing and sale to a natural gas pipeline. Each alternative was rejected, in part because Mountain Coal had no clear authority at the time to put the CMM to use, and because of the many economic, legal, and logistical difficulties associated with each. The January 15, 2009 lease amendments removed at least the legal obstacle, warranting a fresh look at each option.

For additional ideas, Mountain Coal consulted independent experts, did internal brainstorming, and reviewed materials published by EPA's Coal Mine Methane program. This process yielded several other potential options, including:

1) On-site electricity generation;

2) Electrical generation coupled with solar thermal supplementation;

3) Combustion for incremental mine heating;

4) On-site processing for fuels, such as liquefied natural gas ("LNG"); and

5) Use of CMM for chemical feedstocks, as referenced in EPA's "Methane to Markets" publications.

Of these, Mountain Coal decided to examine on-site electrical generation and electrical generation coupled with solar thermal supplementation for additional review. These had some conceptual attraction because electrical transmission lines with significant capacity already run to the Mine, potentially allowing Mountain Coal to leverage existing infrastructure. Mountain Coal also looked at several variations within the flaring, electrical generation, and gas sales options.

The remaining alternatives did not warrant detailed analysis. A review of mine heating needs resulted in a determination that there is little incremental need for mine heating beyond current practices. Mountain Coal also determined the fuel processing to LNG was unlikely to present a substantially different cost profile from sale to a natural gas pipeline. Fuel processing would require essentially all the processing steps and equipment as for natural gas, plus additional processing, and present difficult transportation challenges, in that LNG tankers would need to transport all fuel from the Mine site. Finally, there are limited ready users of LNG in the vicinity of the Mine. Consequently, Mountain Coal concluded that processing for sale to natural gas pipeline was a more productive alternative to analyze in detail. Finally, Mountain Coal concluded that use of CMM for chemical feedstocks is not economically viable, principally owing to West Elk's remote location. Methane is abundant and inexpensive in the chemical processing centers on the Gulf Coast and East Coast. Delivering West Elk CMM to existing chemical plants would merely replicate the pipeline and fuels options, and constructing chemical processing facilities at the Mine site would be overly capital and space intensive.

B. Independent Evaluation of Technical and Economic Feasibility Components

Mountain Coal determined to have as much of the R2P2 analyses conducted by independent specialists as possible. Shortly after negotiating the lease amendments, Mountain Coal contacted a variety of natural gas collection, processing and power generation consultants. After receiving the R2P2 direction letter from the BLM in March 2009, Mountain Coal retained several outside firms and instructed them to prepare the technical reports and analyses attached to this report by the BLM's September 2009 deadline.

These analyses began with E Seam CMM composition and volume. Rough and conservative estimates of E Seam gas generation had been provided for the environmental review process, but a more precise and detailed analysis would be required for the R2P2 process. Mountain Coal had retained Schlumberger for a general forecast of E Seam CMM production in 2007, and provided these reports to Arista Midstream Services LLC ("Arista"), a natural gas collection and delivery firm for additional review. Additionally, actual E Seam MDW production data Mountain Coal had accumulated by the time the R2P2 report was due was provided to Arista as well.

Arista was also retained to prepare a conceptual design for a CMM collection and gathering system, bringing all CMM to a central location for flaring, combustion in power generators, and/or processing for delivery to a natural gas pipeline. Arista was further assigned the tasks of researching potential CMM flaring equipment, designing a gas processing facility, and examining pipeline delivery options. Each of these tasks fit within Arista's specialty of low pressure gas collection and delivery systems. The Arista analyses are found in **Exhibit F** to this Report.

Mountain Coal retained Burns & McDonnell Engineering Company, Inc. ("Burns & McDonnell"), to analyze options for using CMM to generate electricity. This included generator types, pollution control and permitting issues, a review of electricity energy and capacity pricing, and examination of the solar/thermal option. Burns & McDonnell was further assigned to incorporate the Arista data, economic feasibility information, and carbon valuation materials into models that would allow feasibility comparisons and sensitivity analyses of the various CMM use options. The Burns & McDonnell report is **Exhibit G** to this Report.

Mountain Coal hired Verdeo Group, Inc. ("Verdeo") to examine issues associated with VAM collection and management, and the current state and potential future course of carbon pricing, crediting, and markets. Verdeo's analyses are presented in **Exhibits H** (VAM) and **Exhibit I** (carbon markets).

Finally, Mountain Coal internally calculated its own current cost of capital for use in the Burns & McDonnell report. Mountain Coal's parent has recently participated in the debt markets, and therefore could reliably evaluate its cost of debt and equity financing using independent market data and generally recognized valuation models. The Cost of Capital discussion is provided in Section IIIA to this R2P2 Report and the accompanying Confidential Report – Mountain Coal Company Cost of Capital Calculations for West Elk Mine E Seam Coal Mine Methane Economic Feasibility Analyses ("Confidential Cost of Capital Financial Analysis").

C. Mountain Coal Submission of R2P2 Report

Following receipt, Mountain Coal has collected all of the individual consultant reports in this R2P2 Report, and coordinated communications among the consultants to ensure that all were using common assumptions and sharing information as needed.

As discussed, Mountain Coal has prepared an analysis of its cost of capital, as requested by the BLM. Although some of the information in the cost of capital study is public, Mountain Coal's analysis is not. Consequently, Mountain Coal has segregated the cost of capital discussion into a separate and concurrently filed Confidential Cost of Capital Financial Analysis. Mountain Coal does not object to public disclosure (in accordance with BLM's standard procedures for disclosure of R2P2 documents) of the *result* of the cost of capital analysis, i.e., the internal rate of return employed by this R2P2 Report, but does request that the underlying report be maintained as confidential.

The evaluation of alternatives that follows in the next section centers around the consultants' reports. For each section, however, Mountain Coal identifies the key assumptions that were provided to the consultants, and provides its own observations regarding the consultants' reports.

III.
ANALYSIS

A. Standards Used in this Report

1. Economic Feasibility Standard

The E Seam coal lease addenda, mining plan approvals, and March 25, 2009 BLM Letter all condition capture or other use of CMM on economic feasibility. However, none of these documents explicitly define "economic feasibility." The March 25, 2009 BLM Letter provides the most guidance, in requesting that Mountain Coal calculate a "reasonable cost of capital and employ commonly used analytical tools used in project finance, such as a discounted cash flow analysis." The BLM Letter is consistent with Mountain Coal's view that, in the absence of any current regulations restricting venting of CMM, the R2P2 analysis should focus on the commercial viability of CMM use options. Consequently, a CMM approach is "economically feasible" within the meaning of the coal lease addenda, mining plan approvals, and BLM Letter, if a project generates sufficient revenues (or cost savings or other economic benefits) to justify Mountain Coal's investment of its own capital in the project. Importantly, however, Mountain Coal has not sought to earn a return comparable to what it would seek in a commercial venture. Rather, Mountain Coal has sought only to avoid sustaining an economic loss on any CMM use project. Put another way, Mountain Coal must achieve an "internal rate of return" on the project of sufficient to avoid losing money on the venture, which in this case is a return that at least equals Mountain Coal's cost of capital.

A cost of capital standard requires specification of two additional parameters – (1) the appropriate entity for whom the standard will be calculated, and (2) the appropriate mix of debt and equity. As to the former, Mountain Coal has elected to use the cost of capital of its ultimate corporate parent, Arch Coal, Inc. ("Arch"). This is the most favorable (i.e., will result in the *lowest* cost of capital) standard by which the project could be measured. Arch is a broadly diversified, multi-billion dollar corporation with substantial assets, a proven market track record, and established, long term revenue streams. As such, Arch enjoys ready access to the capital markets at reasonable terms. From a project perspective, Mountain Coal would have been equally or more justified in calculating a cost of capital for Mountain Coal itself, the West Elk Mine, or for the CMM project as a stand-alone enterprise. In each case, the analysis would have successively focused more closely on the CMM project, and a calculation based solely on the CMM project would arguably have been the most accurate benchmark for the merits of CMM development. By using Arch as the capital entity, Mountain Coal is effectively subsidizing a potential CMM project with Arch's overall portfolio. Nevertheless, because Mountain Coal has the flexibility to obtain capital through Arch, for this Report Mountain Coal elected to use Arch as the entity seeking financing.

Second, Mountain Coal must select the blend for debt and equity financing applicable to the CMM project. As discussed in the Confidential Cost of Capital Financial Analysis, there is no set rule regarding selection of debt or equity financing. The report describes how Mountain Coal selected the blend applied in the economic feasibility analysis.

The calculation of the resulting cost of capital and internal rate of return is also set forth in the concurrently submitted Confidential Cost of Capital Financial Analyses.

2. <u>Safety Standard</u>

The coal lease addenda and mining plan approvals make clear that any CMM use is to be consistent with mine safety. For purposes of this analysis, Mountain Coal instructed all consultants that any proposed CMM controls or processing technology must be designed to:

- ensure effective evacuation of CMM from the mine;

- eliminate any risk of CMM ignition propagating down MDWs or to the active gob;

- protect surface facilities and personnel from explosions, methane releases to breathing zones;

- protect surface resources such as trees from fire hazards, explosions, or deleterious exposure to methane concentrations.

In each case consultants were asked to specifically assess timing and process concerns related to MSHA permitting and standards.

3. Operational Standard

In addition to economic feasibility and safety standards, Mountain Coal instructed its consultants to work with Mine personnel to ensure operational feasibility. Specifically, this means that any CMM control or processing equipment must be compatible with ongoing longwall mining and contingencies. For example, during the second quarter of 2009 the Mine encountered a parting of the coal seam. This resulted in a slowdown of coal production and a decline in CMM generation. While individually unexpected, these types of production upsets occur periodically in underground coal mining. Any CMM control method must therefore be sufficiently robust and flexible to adjust to slowdowns in CMM production. If, for instance, Mountain Coal could sell CMM-fueled electricity to the local utility, but only if Mountain Coal could guarantee a minimum continuous delivery, the generators would need to be significantly undersized relative to average CMM flows so as to ensure the required minimum power delivery.

Similarly, Mountain Coal directed consultants to consider CMM control compatibility with Mountain Coal's existing permits and leases. For example, Mountain Coal's permits and mining plan approvals identify specific locations and numbers of MDWs. Methane production could conceivably change with a different number or locations of wells, but neither of these activities is authorized by the present leases or mining plans, and therefore Mountain Coal excluded such practices from the scope of the R2P2 Report.

Finally, the lease addenda and mining plan approvals clearly state that all otherwise applicable environmental review and permitting requirements remain in effect. Mountain Coal therefore instructed consultants to consider and address MSHA approval, environmental review, surface restrictions, Clean Air Act permitting, and such other permitting constraints and timelines as might be applicable.

4. Federal Royalty Standard

Federal gas that is captured under a Mountain Coal coal lease and either sold or converted to a commercial use such as for generation of electric power for sale is subject to a Federal royalty. CMM or extracted methane gas vented or discharged for safety purposes, used by Mountain Coal for the benefit of the mine or flared does not bear the Federal royalty.

The Coal Leases addenda provides that the royalty "shall be 12.5% of the value of any coal mine methane that is captured for use or sale." "Use or sale" does not include CMM that is vented or discharged for safety reasons. The Coal Leases are expressly made subject to Title 30 of the CFR relating to gas reporting and measurement under the addenda.

Regulations for valuation of Federal natural gas production are structured on a benchmark system. 30 CFR 206.152(c), 206.153(c). The value of natural gas for royalty purposes is first established in accordance with sales that occur under the terms of an arm's-length contract. 30 CFR 206.152(a)(1). An arm's-length contract is defined as a contract or agreement that has been arrived at in the market place between independent, non-affiliated persons with opposing economic interests. 30 CFR 206.151. If no arm's length contract exists, then the value of the gas sold will be determined based upon the first applicable of the following benchmarks:

- Gross proceeds received under a non-arm's length contract if it is comparable to that received under an arm's-length agreement. Price, duration, terms, quality and volumes are considered.

- Determination of value by consideration of all relevant information, including gross proceeds under an arm's-length contracts for like-quality gas in the same field or nearby area, spot sales, and other information.

- A net-back method for calculating market value under which costs of transportation, processing or manufacturing are deducted from the proceeds received for the gas at the first point at which reasonable values may be determined by an arm's length sale or by comparisons to other sales.

For purposes of this R2P2 Report, a Federal royalty of 12.5% has been used in the economic calculations for Option 3 involving sales of E Seam gas to a pipeline and Option 2 involving use of E Seam gas for electric power generation. As provided in the Coal Leases addenda, no royalty is owed on CMM flaring. Gross proceeds calculations are based on assumed sales under arms-length contracts. Gas sales prices and comparable arm's-length values for produced gas are derived from data generated by Arista and are discussed in Section IIIB based on Rocky Mountain gas region prices.[2]

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[2] The source used for Rocky Mountain gas prices is the publication *Gas Daily*. Actual pricing point used was CIG Rockies Section in *Gas Daily* for gas priced as delivered to the pipeline. Transportation, gas treatment and compression costs to render the gas to a marketable condition and to transport the gas from the mine to the pipeline were deducted.

5. CMM Assumptions Applicable to All Options

To ensure fair comparison between CMM control options across multiple consultant analyses, Mountain Coal provided several baseline assumptions. These included:

- The E Seam is the CMM source;
- Estimated CMM volumes for all reports would be derived from an analysis prepared by Arista, which concluded average production of 3 million cubic feet/day ("MMcf/d") of raw gas from the active panel, and 1 MMcf/d of gas from sealed panels, averaging 55% methane, as discussed in detail in the Arista report;
- The gas composition of the CMM would also be provided by Arista, based on actual emissions to date from the E Seam;
- Mountain Coal supplied the number and location of MDWs, as approved in Colorado Division of Mining Reclamation and Safety authorizations TR-111 and PR-14;
- All reports should assume that existing surface restrictions will continue;
- All reports should envision a potentially significant range of natural gas prices and prices for megawatt/hour of electricity generated; and
- The effect of potential carbon offsets would be separately calculated.

Each of these assumptions should be considered in evaluating the CMM control options that follow.

B. CMM Use Options

1. CMM Flaring

a. Relevant Technical Reports

The following reports are most directly related to CMM flaring:

Consultant	*Scope*	*Report*
Arista	CMM flaring technology; Design of gathering system	Exhibit F

Burns & McDonnell	Effect of potential revenues from carbon offsets on feasibility	Exhibit G
Verdeo	Carbon Market Assessment	Exhibit I

b. Mountain Coal Observations

Several aspects of flaring stand out in comparison to the other potential CMM control technologies. First, Arista opines that it may be feasible to design and implement a safe flaring system. However, the fact that MSHA has never permitted a flare at an active mine means that the time and field testing necessary to secure MSHA approval is unknown. Second, flaring is theoretically less expensive than either power generation or sales to a natural gas pipeline. To the extent that any revenue can be realized from the sale of carbon offsets, flaring thus has a lower economic feasibility hurdle than the other options. Third, because flaring produces no revenue other than from carbon offsets, its economic viability is entirely dependent upon carbon pricing. Fourth, present market prices for carbon offsets are too low to economically justify implementation of flaring. Fifth, it is possible to lower the economic feasibility hurdle by designing a gathering system and flare to be located up the mountain directly over the active mine workings, which would save several million dollars in gathering system costs. However, this gathering system design and flare location poses additional MSHA, Forest Service, and other permitting and operational challenges. It would also foreclose a combination of flaring and electrical generation or gas processing, posing difficult tradeoffs. Moreover, the cost savings for the alternative flare design are insufficient to make that option economically feasible at this time.

There is some reason to believe that carbon offset prices could increase significantly if and when federal cap-and-trade legislation is enacted, but the timing and essential details of that legislation are presently uncertain. For these reasons, Mountain Coal does not believe that flaring is presently economically feasible, but that development of carbon legislation and markets bears monitoring. Flaring appears to be the most likely of the CMM use options to become economically feasible.

2. <u>Gas For Electric Power Generation</u>

a. Relevant Technical Reports

The following reports are most directly related to the power generation options:

Consultant	***Scope***	***Report***
Arista	Design of gathering system	Exhibit F

Burns & McDonnell	Power Generation technologies; electricity pricing; sensitivity analysis	Exhibit G

b. Mountain Coal Observations

Power generation initially appeared as an intriguing CMM option, principally because of already-existing transmission infrastructure and electric utility interest in environmentally friendly power supplies. However, it appears clear that generation is not presently economically feasible. This is due to several factors. First, daily swings in CMM production inhibit consistent, reliable electricity generation. This creates difficulty and extra cost in sizing generators, and reduces the capacity value of the power to the utility. Second, pollution controls and similar permitting constraints measurably increase generation costs. Third, even focusing solely on the energy value of the electricity, the lowest cost generation scenario would require an electricity price more than 150% greater ($114/MWh) than the price paid by the Mine for electricity ($71/MWh). Burns & McDonnell further states that the $71/MWh is at best an upper bound of the price the Mine could obtain for electricity generated on site. It will require either a significant increase in electricity prices or a substantial increase in the value of carbon offsets to make electrical generation economically feasible. Such a combination does not appear likely in the near term, but conceivable over a longer period.

Solar thermal supplementation of CMM-fueled electrical generation is plainly not economically or operationally feasible. Burns & McDonnell's analysis demonstrated that the site is simply not physically a good site for a meaningful solar array.

3. <u>Gas Sales to Pipeline</u>

a. Relevant Technical Reports

The following reports are most directly related to gas processing and sales to a natural gas pipeline:

Consultant	***Scope***	***Report***
Arista	Design of gathering system; Gas Processing designs; Pipeline interconnection routes and costs	Exhibit F
Burns & McDonnell	Natural gas prices; sensitivity analysis	Exhibit G

b. Mountain Coal Observations

Gas sales to a natural gas pipeline is presently the least feasible of the three primary CMM use alternatives, and it does not appear that the pipeline option would be economically viable in the foreseeable future. There are two primary reasons for this conclusion. First, the gas processing equipment is capital intensive, putting gas sales at a significant cost disadvantage, particularly in relation to conventionally produced gas. Second, and most critically, the West Elk is too far removed from pipelines, with the nearest option being nearly 15 miles away. E Seam CMM volumes and production life cycle are far too low and short to justify the cost of laying a 15 mile pipeline interconnection. In addition, carbon crediting protocols may not provide carbon offsets for gas sales to a natural gas pipeline. Economics aside, the pipeline option is also the most operationally challenging, because of the extensive surface work and permitting that would be required to construct the pipeline interconnect.

IV.
CARBON CAPTURE AND CREDITS

A. Relevant Technical Reports

Consultant	*Scope*	*Report*
Verdeo	Carbon Market Assessment	Exhibit I
Burns & McDonnell	Carbon pricing sensitivity analysis	Exhibit G

B. Mountain Coal Observations

Carbon Markets are in a state of deep uncertainty regarding the prospects and details of federal cap-and-trade legislation. This has caused turmoil in carbon prices, and eliminates any prospect that use of West Elk CMM is currently economically feasible. As Verdeo reports, the Environmental Protection Agency forecasts that offset prices will rise substantially if a climate bill is passed. However, the Senate has not yet settled on a bill, and no one knows what a conference committee bill will provide or whether a law will be enacted. Equally importantly, the value of CMM offsets will depend greatly on the specific details of how the final legislation addresses CMM emissions, which is also unknown and subject to ongoing legislative negotiations. Consequently, Mountain Coal has little option but to wait until the fate of federal climate change is determined and carbon markets respond accordingly or a more robust, stable and transparent voluntary offset market is established. Mountain Coal proposes that carbon offset pricing will be one of the key "Study Trigger Values" that Mountain Coal will address in annual updates to this R2P2 Report.

V.
VAM OXIDATION

A. Relevant Technical Reports

Consultant	***Scope***	***Report***
Verdeo	VAM Assessment	Exhibit H

B. Mountain Coal Observations

The driving factor preventing use of VAM is the very high rate of dilution, which is necessitated by safety requirements. As discussed in the Verdeo report, West Elk VAM is estimated to contain only 0.15 to 0.31% methane by volume (and spot readings vary greatly). At the low end, these concentrations are too low to operate thermal oxidizing equipment, which requires consistent concentrations above 0.20% methane. At all ranges there is too little energy content to operate any equipment economically, which requires a minimum of 0.40% methane. Finally, even if these technical and economic obstacles could be overcome, over half the VAM released from the E-Seam ventilation shaft cannot be accessed, due to site constraints and the limitations of thermal oxidizing intake systems. A single VAM processing unit is in operation at an active mine in the United States, but Verdeo concluded that the technology used at that mine or offered by other vendors is not technically feasible at the West Elk Mine. Verdeo, which is a strong proponent of VAM use, considers the prospects of VAM use at West Elk to be "bleak." For safety reasons, the central function of a mine ventilation system is to flush CMM out of the active areas of the mine at very low concentrations, and the particular circumstances of West Elk Mine ventilation renders its VAM unfit for use.

VI.
GAS MONITORING

The BLM Letter requested information on the methods and equipment used to monitoring VAM emissions and CMM released from E Seam MDWs. Until any CMM use option becomes economically feasible, Mountain Coal will continue to use the equipment in current operation for reporting CMM emissions to MSHA. These are described in a memorandum attached as **Exhibit J**. If any of the disposal or processing alternatives are constructed, the equipment will contain additional metering devices that will provide continuous flow readings.

VII.
PROCESS FOR ANNUAL REPORT UPDATES

The BLM Letter identifies a need for annual updating of the R2P2 report. Given that none of the CMM use options are presently economically feasible, Mountain Coal proposes a two step screening process for future annual updates. In Step One, Mountain Coal will examine August prices on three "Study Trigger Values" that drive economic feasibility. These are:

(a) Natural gas prices, as forecasted by Gas Daily for the next 10 years;

(b) Price per Megawatt/Hour for electricity paid by the Mine; and

(c) Carbon Offset prices.

In each case, Mountain Coal proposes that the Study Trigger Value be the Internal Rate of Return Hurdle Value identified in the Burns & McDonnell Report. If current prices for any Study Trigger Value equal or exceed the relevant Burns & McDonnell Hurdle Value, then Mountain Coal would do a detailed updated evaluation of the relevant options. Thus, for example, the current Burns & McDonnell Hurdle Value for the power generation option is \$114/MWh for the most economic power generation option – reciprocating engine. If the August 2010 price paid by the Mine for electricity is \$114/MWh or greater, this will trigger Mountain Coal to re-examine the power generation option. Similarly, if carbon offset prices reach \$19.25/ton (the Hurdle Value for the base system for flaring), Mountain Coal would re-examine Flaring. As long as the Study Trigger Values remain below the Hurdle Values, no further analysis would be required.

Step Two would be a brief survey of new developments in CMM control technology, as reported by EPA's Methane to Markets program. If new or substantially improved commercially demonstrated CMM control equipment emerges over the course of a year, Mountain Coal will prepare an R2P2 supplement addressing the potential applicability to the West Elk Mine.

VIII.
SUMMARY

Since issuance of the January 14, 2009 coal lease amendments authorizing Mountain Coal to devise beneficial uses of E Seam coal mine methane, Mountain Coal has engaged in an intensive analysis of a wide range of options. It is disappointing that no technology presently exists that would allow an economically feasible use of the methane, particularly given the aggressive financing assumptions Mountain Coal applied. However, the coming year may see dramatic developments in climate change legislation, which could create a more favorable carbon market and regulatory environment, and may render one or more options more economically feasible. At present the most prudent course appears to be to revisit the key commodity and carbon market benchmarks in a year's time, and then reassess the feasibility of a project.

EXHIBITS

Exhibit A – BLM Letter

Exhibit B – BLM Presentation at 2008 U.S. Coalbed Methane Conference

Exhibit C – Coal Lease Addenda, Leases C-1362, COC-56447 and COC-67232

Exhibit D – TR 111 - Federal Coal Leases C-1362 and COC-56447

Exhibit E – PR-14 - Federal Coal Leases C-1362 and COC-67232

Exhibit F – Arista Report

Exhibit G – Burns & McDonnell Report

Exhibit H – Verdeo VAM Analysis

Exhibit I – Verdeo Carbon Market Analysis

Exhibit J – Gas Monitoring Methods

EXHIBIT A

BLM LETTER

United States Department of the Interior

BUREAU OF LAND MANAGEMENT
Colorado State Office
2850 Youngfield Street
Lakewood, Colorado 80215-7093
www.blm.gov/co

TAKE PRIDE IN AMERICA

In Reply Refer to:
3420 (CO-921)
C-1362, COC56447, COC67232

AR 25 2009

Gene E. DiClaudio
President
Mountain Coal Company
One Cityplace Drive, Ste. 300
St. Louis, MO 63141

Dear Mr. DiClaudio:

As a result of the January 16, 2009 addendum to the West Elk Leases and the language contained in the Technical Revision No. 111 and PR 14 approval documents, the Bureau of Land Management (BLM) is requiring that Mountain Coal Company supplement the existing Resource Recovery and Protection Plan (R2P2) to comply with the language contained in the addendum and the approval document.

The Revision No. 111 and PR 14 approval document directs Mountain Coal Company to collect all economical Coal Mine Methane (CMM) and Vent Air Methane (VAM) that would normally be vented for the safety of the miners and compliance with applicable MSHA regulations. The addendum to the Mountain Coal Company leases provided a mechanism that allows for the capture and use of the CMM and VAM. To ensure compliance with the addendum and the approval document Mountain Coal Company must supplement the existing R2P2 to include an annual evaluation of the economics associated with the capture and/or use of the CMM and VAM. The economic evaluation should contain at a minimum the following:

- An analysis of the costs associated with collection of vented CMM from holes developed specifically for the purpose of the venting of the CMM for safety purposes.
- An analysis of the costs associated with collection/capture of VAM
- All costs associated with the collection of the CMM that is above and beyond what is associated with normal venting operations including but not limited to construction of gathering systems, roads, pipelines, etc.
- All costs associated with putting the CMM or VAM in a marketable condition including compressing and refining systems and transportation to the point of sale.
- An analysis of the costs associated with collection and beneficial use of CMM or VAM.
- All projected revenue from the sale of the CMM or VAM.

- Any carbon credit offsets acquired as a result of the capture/sale of the CMM or VAM must be taken into account.
- The economic evaluation will include a reasonable cost of capital and employ commonly used analytical tools used in project finance, such as a discounted cash flow analysis.

CMM or VAM that is used on site for beneficial use will not be subject to a royalty. Beneficial use includes all uses of CMM or VAM onsite including fueling mine heaters and the generation of electricity that is used onsite at the West Elk Mine. Vented or flaired CMM or VAM that is not economic is not subject to a royalty.

All activities associated with the beneficial use or economic collection and sale of CMM or VAM must be approved in a supplement to the R2P2. The R2P2 must be supplemented to include the methods and equipment used to measure all CMM or VAM that is used for beneficial use or sold. The measurement of CMM or VAM sold should comply with the applicable measurement regulations found at 43 CFR 3162.7-3 and Oil and Gas Onshore Order No. 5.

Within six months of receipt of this letter Mountain Coal Company is required to provide to the appropriate Bureau of Land Management office an economic evaluation of the capture and use of the CMM and VAM and a proposal detailing the equipment and methodology to be used in monitoring the CMM or VAM production. The reported produced value for VAM should be the same value currently reported to the BLM as part Mountain Coal Company's methane venting submittal until such time that capture of VAM is considered economic at which time a detailed submittal outlining equipment and methodology will be required.

If there are any questions or concerns please feel free to contact Charlie Beecham, Branch Chief for Solid Minerals at (303) 239-3773.

Sincerely

Lynn E. Rust

Lynn E. Rust
Deputy State Director
Energy, Lands and Minerals

Special Challenges on Federal Lands

William Radden-Lesage
Bureau of Land Management
Bill_Lesage@blm.gov

2008 U.S. Coal Mine Methane Conference
October 28, 2008
Pittsburgh, PA

Outline

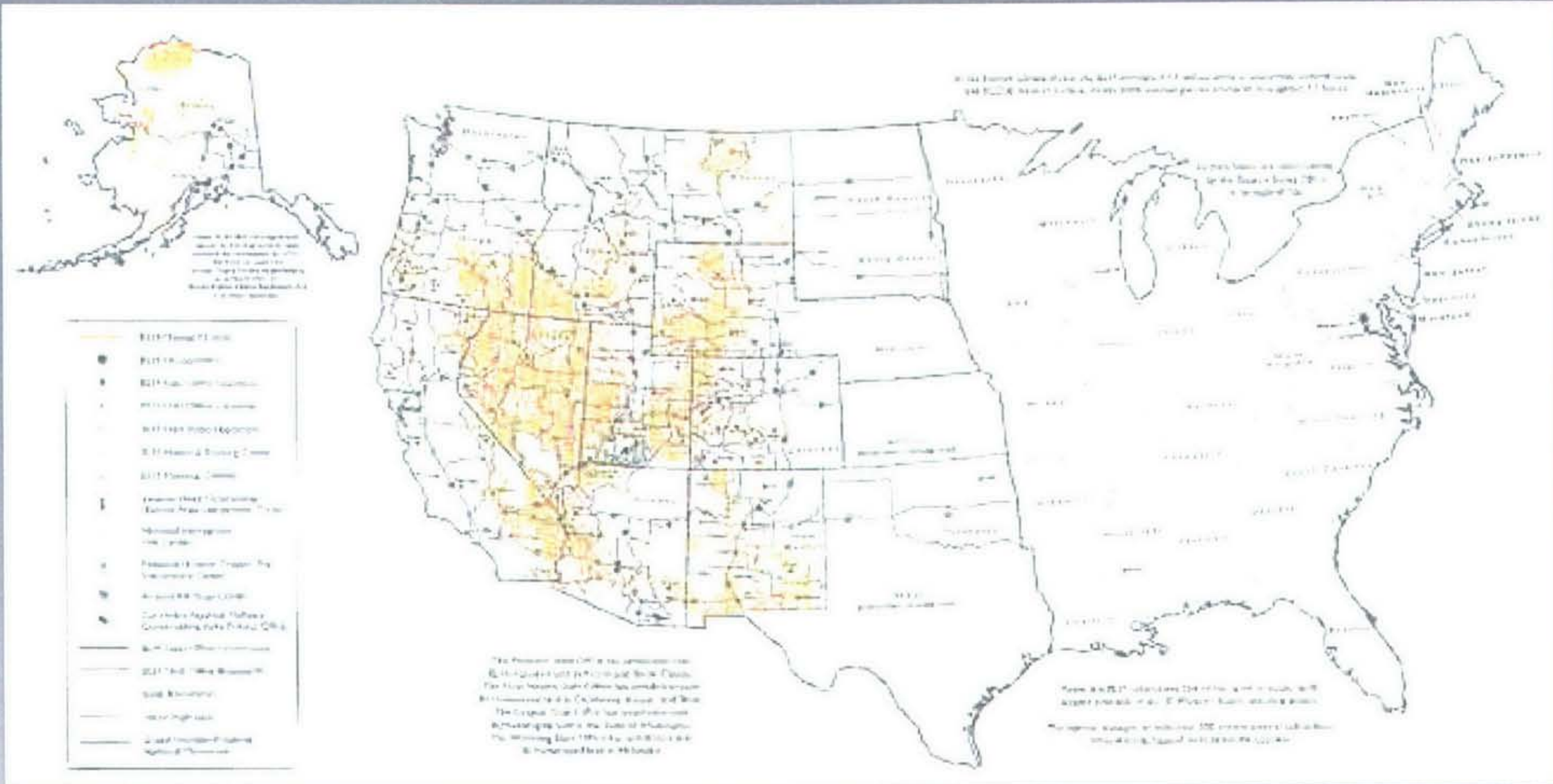
- Chapter 1 – Who is BLM?
- Chapter 2 – Amoco v Southern Ute
- Chapter 3 - The Powder River Basin Policy
- Chapter 4 – The San Juan Basin
- Chapter 5 - Vessels IBLA Decision
- Chapter 6 - What's Next

Who is BLM?

Chapter 1

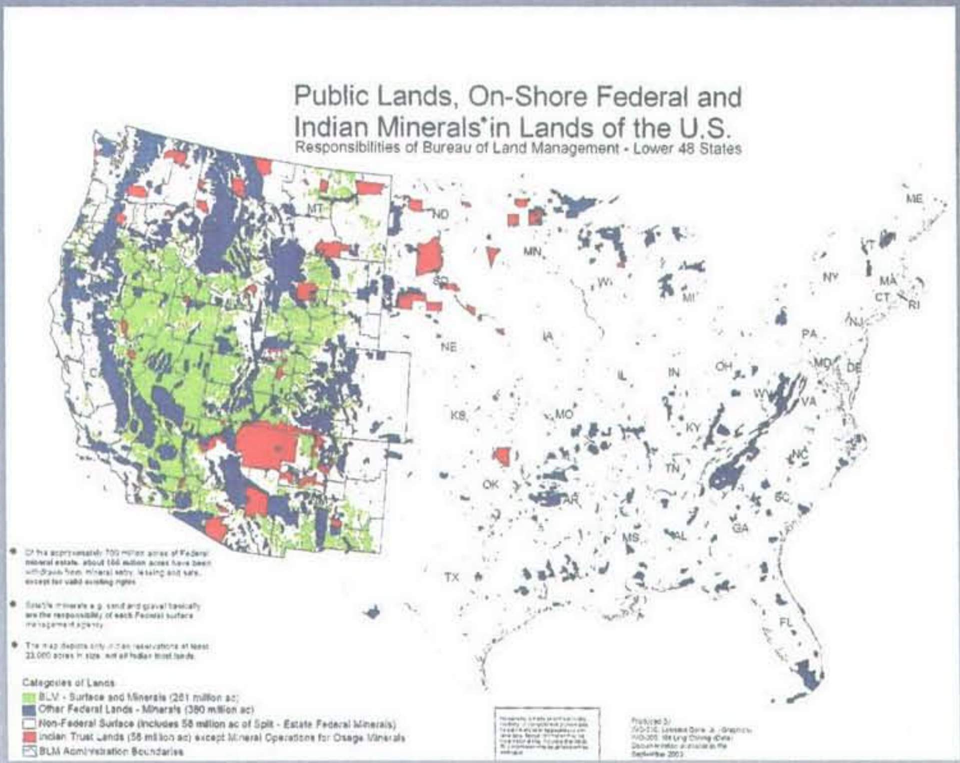
BLM Managed Surface Estate

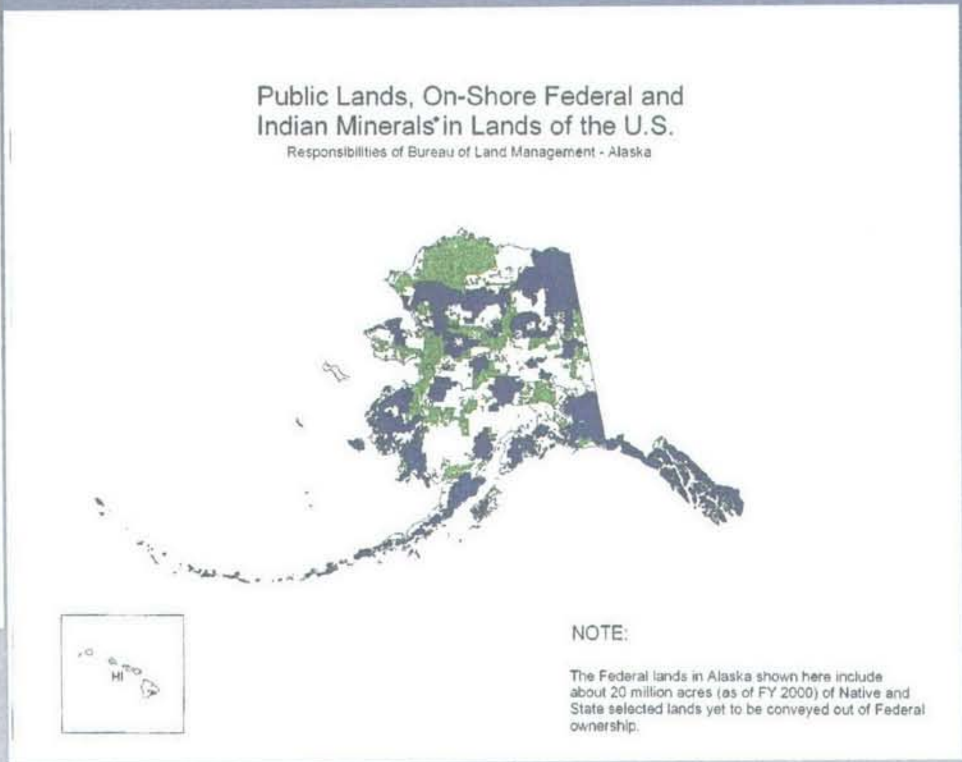
256 million acres



BLM Managed Mineral Estate

700 Million acres
166 Million acres withdrawn
58 Million acres split estate



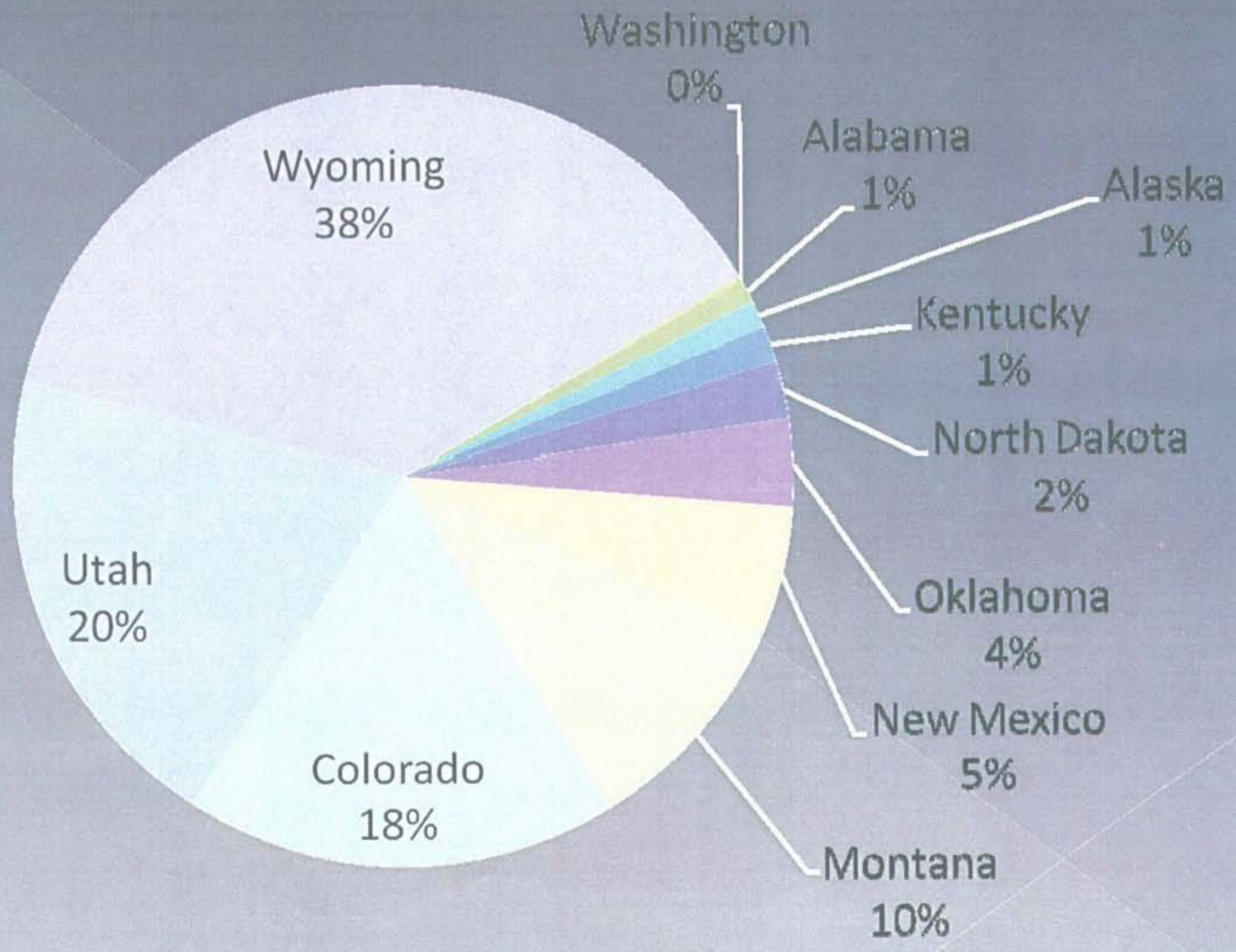


Federal Coal Leasing FY2007

http://www.blm.gov/public_land_statistics/index.htm

State	Leases	Acres
Alabama	4	4,617
Alaska	2	5,148
Colorado	56	83,361
Kentucky	8	6,903
Montana	29	44,181
New Mexico	11	25,432
North Dakota	15	11,062
Oklahoma	9	16,664
Utah	75	92,075
Washington	2	521
Wyoming	87	175,980
Total	298	465,944

Distribution of Federal Coal Leases by Acreage



Additional Considerations

- Split estate lands
- Multiple entities may own minerals within the mine area
  - "First in time, first in right"
  - Interests of other governmental agencies
  - Interests of other mineral lessees
  - Authority limited by the Mineral Leasing Act, as amended

Amoco v Southern Ute

Chapter 2

Amoco v Southern Ute

- (Citation) (June 7, 1999)
- On Coal Lands Act lands, the US reserved only the coal estate.
- Coal bed methane in these lands is owned privately.
- US has no authority to authorize or require coal bed methane capture by a Federal coal lessee on this type of land.
- This decision does not impact BLM's regulation of lands owned by the US in fee simple.

The Powder River Basin (PRB) Policy

Chapter 3

Powder River Basin (PRB) Policy Summary

- Instruction Memorandum 2006-153
  http://www.blm.gov/wo/st/en/info/regulations/Instruction_Memos_and_Bulletins/national_instruction/2006/im_2006-153__.html
- Oil & gas leasing generally predates coal leasing
- Surface mining potentially draining the methane resource
- Applies only in the PBR when the Federal gas estate overlies the Federal coal estate
- Royalty incentive to produce methane within a conflict administration zone ahead of mine development
- In exchange for reduced royalty, the gas lessee will agree to abandon methane development as mine development approaches a methane well

The San Juan Basin

Chapter 4

San Juan Basin

- Similar to the PRB, older federal oil and gas leases predate federal coal leases
- Surface mining has exhausted recoverable reserves and mining is progressing underground
- Coal and oil & gas lessees negotiate
- Coal lessee concern about pre-production of methane ahead of mining
- Royalty reduction solution not implemented
- Recovery systems in place with marginal economics

The Vessels IBLA Decision

Chapter 5

Vessels IBLA Decision

- Vessels Coal Gas, Inc. 175 IBLA 8
- Aberdeen Coal Mine – Mixed coal and gas ownership, coal production moving from non-federal oil & gas to federal oil & gas lands
- There are no existing Federal oil & gas leases above the mine
- Competitive Federal oil & gas lease proposed for methane collection and sale of methane over the federal coal lease
- Unsuccessful bidder (Vessels) appeals, the oil & gas lease was heavily stipulated for the protection of the health and safety of underground miners such that the oil & gas really wasn't an oil & gas lease any longer.

Vessels IBLA Decision

- IBLA concludes that "gob gas", i.e., gas liberated during coal development, is not an oil and gas deposit subject to leasing under the Mineral Leasing Act.
- BLM is investigating other means for authorizing capture of methane liberated by coal mining.

What's Next?

Chapter 6

In general:

- BLM regulatory authority is limited to lands where the US owns both the coal and the gas estates
- BLM must consider any pre-existing and conflicting lease rights
- Under the Vessels decision, BLM may only authorize the coal lessee to capture methane released as part of coal mining

Gas rights predate coal rights

- Policy will continue consistent with the current PRB co-development policy
- Royalty incentive to produce methane ahead of coal severance
- To receive the royalty incentive, the gas lessee must agree to abandon the methane production in advance of mining

Coal rights predate gas rights

- Bilateral agreement between BLM and the coal lessee to amend the coal lease
- To authorize capture of methane that otherwise would be vented as required by MSHA
- Coal operator shall capture methane if
  - Economically feasible, &
  - Does not jeopardize the safety and health of miners
- All applicable laws and regulations will apply

Coal rights predate gas rights (cont.)

- West Elk Mine in Colorado will be the first case
- BLM may rely on the Mineral Leasing Act to authorize coal lessees to capture methane vented as required by the Mine Safety & Health Administration (MSHA).

EXHIBIT C

COAL LEASE ADDENDA

LEASES C-1362, COC-56447

AND COC-67232

United States Department of the Interior Bureau of Land Management **Coal Lease Addendum**	Serial Number **C-1362**

Coal Lease C-1362 is hereby amended by this addendum:

PART I. LEASE RIGHTS GRANTED

* * * *

Sec. 3. Notwithstanding the language in Sec. 2 of this lease and subject to the terms and conditions below, lessee is authorized to drill for, extract, remove, develop, produce and capture for use or sale any or all of the coal mine methane from the above described lands that it would otherwise be required to vent or discharge for safety purposes by applicable laws and regulations. For purposes of this lease, "coal mine methane" means any combustible gas located in, over, under, or adjacent to the coal resources subject to this lease, that will or may infiltrate underground mining operations.

Sec.4. Notwithstanding any other provision of this lease, nothing herein shall, nor shall it be interpreted to, waive, alter or amend lessee's right to vent, discharge or otherwise dispose of coal mine methane as necessary for mine safety or to mine the coal deposits consistent with permitted underground mining operations and federal and state law and regulation. Lessee shall not be obligated or required to capture for use or sale coal mine methane that would otherwise be vented or discharged if the capture of coal mine methane, independent of activities related to mining coal, is not economically feasible or if the coal mine methane must be vented in order to abate the potential hazard to the health or safety of the coal miners or coal mining activities. In the event of a dispute between lessor and lessee as to the economic or other feasibility of capturing for use or sale the coal mine methane, lessor's remedy as a prevailing party shall be limited to recovery of compensatory royalties on coal mine methane not captured for use or sale by lessee. Lessee shall have the right to continue all mining activities under this lease, including venting coal mine methane, pending resolution of any dispute regarding the application of the terms of Sections 3 and 4.

PART II. TERMS AND CONDITIONS

Sec. 2

* * * *

(c) COAL MINE METHANE OPERATIONS AND ROYALTIES - Notwithstanding the language in Part II, Sec. 2 (a) of this lease, the royalty shall be 12.5 percent of the value of any coal mine methane that is captured for use or sale from this lease. For purposes of this lease, the term "capture for use or sale" shall not include and the royalty shall not apply to coal mine methane that is vented or discharged and not captured for the economic or safety reasons described in Part I, Sec. 4 of this lease. Lessee shall have no obligation to pay royalties on any coal mine methane that is used on or for the benefit of mineral extraction at the West Elk coal mine. When not inconsistent with any express provision of this lease, this lease is subject to all rules and regulations related to Federal gas royalty collection in Title 30 of the Code of Federal Regulations now or hereinafter in effect and lessor's rules and regulations related to applicable reporting and gas measurement now or hereinafter in effect.

* * * *

SEVERABILITY - In the event any provision of this addendum is subject to a legal challenge or is held to be invalid, unenforceable or illegal in any respect, the validity, legality and enforceability of this lease will not in any way be affected or impaired thereby and lessee will retain, in accordance with the terms of this lease, the exclusive right and privilege to drill for, mine, extract, remove, or otherwise process and dispose of the coal deposits in, upon or under the lands described in this lease, including the right to vent or discharge coal mine methane for safety purposes as required by applicable laws and regulations.

This Coal Lease Addendum is effective as of the date all parties have executed the Addendum.

MOUNTAIN COAL COMPANY, LLC

Name: ____________________________
Title: ____________________________
Date: ____________________________

THE UNITED STATES OF AMERICA

Name: ____________________________
Title: ____________________________
Date: ____________________________

United States Department of the Interior Bureau of Land Management **Coal Lease Addendum**	Serial Number **COC-56447**

Coal Lease COC-56447 is hereby amended by this addendum:

PART I. LEASE RIGHTS GRANTED

* * * *

Sec. 3. Notwithstanding the language in Sec. 2 of this lease and subject to the terms and conditions below, lessee is authorized to drill for, extract, remove, develop, produce and capture for use or sale any or all of the coal mine methane from the above described lands that it would otherwise be required to vent or discharge for safety purposes by applicable laws and regulations. For purposes of this lease, "coal mine methane" means any combustible gas located in, over, under, or adjacent to the coal resources subject to this lease, that will or may infiltrate underground mining operations.

Sec.4. Notwithstanding any other provision of this lease, nothing herein shall, nor shall it be interpreted to, waive, alter or amend lessee's right to vent, discharge or otherwise dispose of coal mine methane as necessary for mine safety or to mine the coal deposits consistent with permitted underground mining operations and federal and state law and regulation. Lessee shall not be obligated or required to capture for use or sale coal mine methane that would otherwise be vented or discharged if the capture of coal mine methane, independent of activities related to mining coal, is not economically feasible or if the coal mine methane must be vented in order to abate the potential hazard to the health or safety of the coal miners or coal mining activities. In the event of a dispute between lessor and lessee as to the economic or other feasibility of capturing for use or sale the coal mine methane, lessor's remedy as a prevailing party shall be limited to recovery of compensatory royalties on coal mine methane not captured for use or sale by lessee. Lessee shall have the right to continue all mining activities under this lease, including venting coal mine methane, pending resolution of any dispute regarding the application of the terms of Sections 3 and 4.

PART II. TERMS AND CONDITIONS

Sec. 2

* * * *

(c) COAL MINE METHANE OPERATIONS AND ROYALTIES - Notwithstanding the language in Part II, Sec. 2 (a) of this lease, the royalty shall be 12.5 percent of the value of any coal mine methane that is captured for use or sale from this lease. For purposes of this lease, the term "capture for use or sale" shall not include and the royalty shall not apply to coal mine methane that is vented or discharged and not captured for the economic or safety reasons described in Part I, Sec. 4 of this lease. Lessee shall have no obligation to pay royalties on any coal mine methane that is used on or for the benefit of mineral extraction at the West Elk coal mine. When not inconsistent with any express provision of this lease, this lease is subject to all rules and regulations related to Federal gas royalty collection in Title 30 of the Code of Federal Regulations now or hereinafter in effect and lessor's rules and regulations related to applicable reporting and gas measurement now or hereinafter in effect.

* * * *

SEVERABILITY - In the event any provision of this addendum is subject to a legal challenge or is held to be invalid, unenforceable or illegal in any respect, the validity, legality and enforceability of this lease will not in any way be affected or impaired thereby and lessee will retain, in accordance with the terms of this lease, the exclusive right and privilege to drill for, mine, extract, remove, or otherwise process and dispose of the coal deposits in, upon or under the lands described in this lease, including the right to vent or discharge coal mine methane for safety purposes as required by applicable laws and regulations.

This Coal Lease Addendum is effective as of the date all parties have executed the Addendum.

MOUNTAIN COAL COMPANY, LLC	**THE UNITED STATES OF AMERICA**
Name: ______________________	Name: ______________________
Title: ______________________	Title: ______________________
Date: ______________________	Date: ______________________

United States Department of the Interior Bureau of Land Management **Coal Lease Addendum**	Serial Number **COC-67232**

Coal Lease COC-67232 is hereby amended by this addendum:

PART I. LEASE RIGHTS GRANTED

* * * *

Sec. 3. Notwithstanding the language in Sec. 2 of this lease and subject to the terms and conditions below, lessee is authorized to drill for, extract, remove, develop, produce and capture for use or sale any or all of the coal mine methane from the above described lands that it would otherwise be required to vent or discharge for safety purposes by applicable laws and regulations. For purposes of this lease, "coal mine methane" means any combustible gas located in, over, under, or adjacent to the coal resources subject to this lease, that will or may infiltrate underground mining operations.

Sec.4. Notwithstanding any other provision of this lease, nothing herein shall, nor shall it be interpreted to, waive, alter or amend lessee's right to vent, discharge or otherwise dispose of coal mine methane as necessary for mine safety or to mine the coal deposits consistent with permitted underground mining operations and federal and state law and regulation. Lessee shall not be obligated or required to capture for use or sale coal mine methane that would otherwise be vented or discharged if the capture of coal mine methane, independent of activities related to mining coal, is not economically feasible or if the coal mine methane must be vented in order to abate the potential hazard to the health or safety of the coal miners or coal mining activities. In the event of a dispute between lessor and lessee as to the economic or other feasibility of capturing for use or sale the coal mine methane, lessor's remedy as a prevailing party shall be limited to recovery of compensatory royalties on coal mine methane not captured for use or sale by lessee. Lessee shall have the right to continue all mining activities under this lease, including venting coal mine methane, pending resolution of any dispute regarding the application of the terms of Sections 3 and 4.

PART II. TERMS AND CONDITIONS

Sec. 2

* * * *

(c) COAL MINE METHANE OPERATIONS AND ROYALTIES - Notwithstanding the language in Part II, Sec. 2 (a) of this lease, the royalty shall be 12.5 percent of the value of any coal mine methane that is captured for use or sale from this lease. For purposes of this lease, the term "capture for use or sale" shall not include and the royalty shall not apply to coal mine methane that is vented or discharged and not captured for the economic or safety reasons described in Part I, Sec. 4 of this lease. Lessee shall have no obligation to pay royalties on any coal mine methane that is used on or for the benefit of mineral extraction at the West Elk coal mine. When not inconsistent with any express provision of this lease, this lease is subject to all rules and regulations related to Federal gas royalty collection in Title 30 of the Code of Federal Regulations now or hereinafter in effect and lessor's rules and regulations related to applicable reporting and gas measurement now or hereinafter in effect.

* * * *

SEVERABILITY - In the event any provision of this addendum is subject to a legal challenge or is held to be invalid, unenforceable or illegal in any respect, the validity, legality and enforceability of this lease will not in any way be affected or impaired thereby and lessee will retain, in accordance with the terms of this lease, the exclusive right and privilege to drill for, mine, extract, remove, or otherwise process and dispose of the coal deposits in, upon or under the lands described in this lease, including the right to vent or discharge coal mine methane for safety purposes as required by applicable laws and regulations.

This Coal Lease Addendum is effective as of the date all parties have executed the Addendum.

MOUNTAIN COAL COMPANY, LLC

Name: ______________________________
Title: ______________________________
Date: ______________________________

THE UNITED STATES OF AMERICA

Name: ______________________________
Title: ______________________________
Date: ______________________________

EXHIBIT D

TR 111, FEDERAL COAL LEASE C-1362

AND COC-56447

UNITED STATES
DEPARTMENT OF THE INTERIOR

This mining plan approval document is issued by the United States of America to:

Mountain Coal Company, L.L.C.
P.O. Box 591
Somerset, Colorado 81434

for a mining plan modification for Federal leases C-1362 and COC-56447 at the West Elk Mine. The approval is subject to the following conditions. Mountain Coal Company, L.L.C. is hereinafter referred to as the operator.

1. Statutes and Regulations.--This mining plan approval is issued pursuant to Federal leases C-1362 and COC-56447; the Mineral Leasing Act of 1920, as amended (30 U.S.C. 181 et seq.); and in the case of acquired lands, the Mineral Leasing Act for Acquired Lands of 1947, as amended (30 U.S.C. 351 et seq.). This mining plan approval is subject to all applicable regulations of the Secretary of the Interior which are now or hereafter in force; and all such regulations are made a part hereof. The operator shall comply with the provisions of the Water Pollution Control Act (33 U.S.C. 1151 et seq.), the Clean Air Act (42 U.S.C. 7401 et seq.), and other applicable Federal laws.

2. This document approves the mining plan modification for Federal leases C-1362 and COC-56447 at the West Elk Mine and authorizes coal development or mining operations on the Federal leases within the area of mining plan approval. This authorization is not valid beyond:

   Township 13 South, Range 90 West 6th P.M.
   Sections 26, 27, 28, 34 and 35 portions thereof.

   These lands encompass ten (10.0) acres and are found on the USGS 7.5 minute Quadrangle map of Somerset, Colorado as shown on the map appended hereto as Attachment A.

3. The operator shall conduct coal development and mining operations only as described in the complete permit application package approved by the Colorado Division of Reclamation, Mining and Safety, except as otherwise directed in the conditions of this mining plan approval.

4. The operator shall comply with the terms and conditions of the lease, this mining plan approval, and the requirements of Colorado State Permit No. C-1980-007 issued under the Colorado State program, approved pursuant to the Surface Mining Control and Reclamation Act of 1977 (30 U.S.C. 1201 et seq.).

5. This mining plan approval shall be binding on any person conducting coal development or mining operations under the approved mining plan and shall remain in effect until superseded, canceled, or withdrawn.

6. If during mining operations unidentified prehistoric or historic resources are discovered, the operator shall ensure that the resources are not disturbed and shall notify the Colorado Division of Reclamation, Mining and Safety and the Office of Surface Mining Reclamation and Enforcement (OSM). The operator shall take such actions as are required by the Colorado Division of Reclamation, Mining and Safety in coordination with OSM.

7. The Secretary retains jurisdiction to modify or cancel this approval, as required, on the basis of further consultation with the U.S. Fish and Wildlife Service pursuant to section 7 of the Endangered Species Act, as amended, 16 U.S.C. 1531 *et seq.*

8. If, under a bilateral agreement with the Federal lessee, the Bureau of Land Management amends Federal leases C-1362 and COC-56477 to authorize the capture of coalbed gas that would otherwise be vented as required by the Mine Safety and Health Administration, the operator ~~shall~~ capture the vented coalbed gas if such capture is economically feasible and does not jeopardize the safety or health of the miners. The capture operations must comply with the terms of the amended leases and all applicable laws and regulations, including those administered by the U.S. Forest Service and the Colorado State program.

Assistant Secretary
Land and Minerals Management

July 31, 2008
Date

Attachment A

<u>EXHIBIT E</u>

PR-14, FEDERAL COAL LEASE C-1362

AND COC-67232

UNITED STATES
DEPARTMENT OF THE INTERIOR

This mining plan approval document is issued by the United States of America to:

Mountain Coal Company, L.L.C.
P.O. Box 591
Somerset, Colorado 81434

for a mining plan modification for Federal leases C-1362 and COC-67232 at the West Elk Mine. The approval is subject to the following conditions. Mountain Coal Company, L.L.C. is hereinafter referred to as the operator.

1. Statutes and Regulations.--This mining plan approval is issued pursuant to Federal leases C-1362 and COC-67232; the Mineral Leasing Act of 1920, as amended (30 U.S.C. 181 et seq.); and in the case of acquired lands, the Mineral Leasing Act for Acquired Lands of 1947, as amended (30 U.S.C. 351 et seq.). This mining plan approval is subject to all applicable regulations of the Secretary of the Interior which are now or hereafter in force; and all such regulations are made a part hereof. The operator shall comply with the provisions of the Water Pollution Control Act (33 U.S.C. 1151 et seq.), the Clean Air Act (42 U.S.C. 7401 et seq.), and other applicable Federal laws.

2. This document approves the mining plan modification for Federal leases C-1362 and COC-67232 at the West Elk Mine and authorizes coal development or mining operations on the Federal leases within the area of mining plan approval. This authorization is not valid beyond:

   Township 13 South, Range 90 West 6th P.M.
   Sections: 29, 32, 33, 34, 35, portions thereof.

   Township 14 South, Range 90 West 6th P.M.
   Sections: 1, 2, 3, 4, 9, 10 and 11, portions thereof.

   These lands encompass 47.5 disturbed surface acres and are found on the USGS 7.5 minute Quadrangle map of Somerset, Colorado as shown on the map appended hereto as Attachment A.

3. The operator shall conduct coal development and mining operations only as described in the complete permit application package approved by the Colorado Division of Reclamation, Mining and Safety, except as otherwise directed in the conditions of this mining plan approval.

4. The operator shall comply with the terms and conditions of the lease, this mining plan approval, and the requirements of Colorado State Permit No. C-1980-007 issued under the Colorado State program, approved pursuant to the Surface Mining Control and Reclamation Act of 1977 (30 U.S.C. 1201 et seq.).

5. This mining plan approval shall be binding on any person conducting coal development or mining operations under the approved mining plan and shall remain in effect until superseded, canceled, or withdrawn.

6. If during mining operations unidentified prehistoric or historic resources are discovered, the operator shall ensure that the resources are not disturbed and shall notify the Colorado Division of Reclamation, Mining and Safety and the Office of Surface Mining Reclamation and Enforcement (OSM). The operator shall take such actions as are required by the Colorado Division of Reclamation, Mining and Safety in coordination with OSM.

7. The Secretary retains jurisdiction to modify or cancel this approval, as required, on the basis of further consultation with the U.S. Fish and Wildlife Service pursuant to section 7 of the Endangered Species Act, as amended, 16 U.S.C. 1531 *et seq.*

8. Once all necessary permits and other clearances are obtained, the operator shall capture all coalbed gas that would otherwise be vented as required by the Mine Safety and Health Administration if such capture is economically feasible and does not jeopardize the safety or health of the miners. The capture operations must comply with the terms of the amended leases and all applicable laws and regulations, including those administered by the U.S. Forest Service and the Colorado State program.

Assistant Secretary
Land and Minerals Management

1/15/2009
Date

Attachment A

EXHIBIT F

ARISTA REPORT

Prepared for Mountain Coal Company LLC

West Elk Mine
Somerset, Colorado
E Seam Gathering Options
September, 2009

Qualifications

Arista Midstream Services, LLC, is an energy services company focused primarily in the Rocky Mountain Region. Arista was formed in October 2007 with a management team each having over 20 years experience in the midstream energy business, which includes sale and marketing of natural gas, natural gas liquids, and oil. In addition, they have built and operated facilities to move these products to end markets (pipelines, compression facilities, gas treatment facilities, and metering). The project manager on the West Elk Mine project was Tim Pimmel, Vice President of Operations and Engineering. Mr. Pimmel has 10 years of experience in the design, construction, and operation of low pressure gathering systems, primarily in the Powder River Basin in Wyoming.

More information on Arista can be found in **Appendix A** (page 20)

Scope of Work

Arista Midstream Services, LLC, was retained by Mountain Coal Company LLC ("Mountain Coal"), to perform an engineering study related to Mountain Coal's West Elk Mine located outside of Somerset, Colorado. This study is a component in a larger set of analyses prompted by January 2009 amendments to coal leases at the West Elk Mine. This study focused on gathering Coal Mine Methane ("CMM") emitted from existing and future E Seam Methane Drainage Wells ("MDWs"). Arista's evaluation included the design of a gathering system, capital estimates, and annual O&M budgets related to the following three CMM disposal/usage options:

(1) Flaring the CMM;

(2) Using raw CMM to fuel generators to produce electricity; and

(3) Processing the raw CMM for distribution and sale to the nearest natural gas pipeline.

The study began on February 10, 2009 with a site visit at the West Elk mine followed up with a meeting in Mountain Coal's Grand Junction office to review the scope of the analysis. A second field trip to West Elk mine took place on May 28 to look at field layout once the snow melt made it possible to look at the pipeline routes. Three additional meetings were held in Grand Junction to update Mountain Coal's management on project progress, gather additional information, and identify initial findings based on research performed by Arista.

Several spreadsheets and reports were provided by Mountain Coal to assist in the study:

2009 E Seam CH4 Quantity Summary
Schlumberger report on E-Seam Gas-In-Place (dated 1/31/07)
Historical Emissions Data

Design Criteria

Gas Volumes

The first step in the project was to estimate gas volumes for the life of the mine, which is critical in the design of the gathering system, both for pipe sizes and compression sizing. Mining of the E seam began around the beginning of 2009, and 6 methane drainage wells produced gas intermittently in 2009. A summary of the data from the total volume is presented in the table below.

E Seam Averages (MMSCFD)		
	Total Gas Flow	Methane
2009		
January	2.69	1.57
February	3.04	1.62
March	2.91	1.57
April	1.91	1.10
May	1.59	0.72
June	0.83	0.27
July	0.83	0.54
August	1.08	0.76

TOTAL DAILY VOLUME FROM E SEAM WELLS (all associated with Long Wall Mining)

Arista determined that the long wall mining operation would produce roughly an average of 3.0MMCF/day of raw CMM through the MDWs associated with the mined panel. Based upon long term experience at West Elk, we expect that volume will be highest generally when the longwall is located at the beginning of a panel (East side) and generally decrease as the longwall moves west through the panel. Both historically and currently in the E Seam, there is significant day-to-day variation in MDW volumes, with total MDW flows during normal operations ranging from a low of 1.5 MMCF/day to peak flows approaching 5.0 MMCF/day. Arista considered the frequency and volume of peak flows in sizing all components of the gas gathering and management systems. In April, the coal production from the mine was drastically reduced and this caused a significant reduction in gas production. It is expected that eventually the mine will return to normal production, although there will be times in the future that production could be lowered again due to either geologic or economic reasons.

Arista also considered effects on the operation of the MDWs as the various panels are sealed. We reviewed the Schlumberger reserve study and also analyzed the performance of previously sealed panels to estimate the amount of gas that would be produced. After considering all data available, we determined the proper design capacity of the system to be 1.0 MMCF/day of raw gas coming from the sealed panels.

Adding the volume from the long wall mining operation and the sealed E panels, we arrive at total production of 4.0 MMCF/day of raw gas, with an instantaneous peak volume of around 6.0 MMCF/day.

Basic Gas Analysis

The next step in the project was to analyze CMM quality. The West Elk Mine takes routine bag samples of the gas from each of the MDWs in service. This data is recorded in the methane discharge spreadsheets, along with the daily volumes. Arista reviewed the sampling process and data on gas quality and determined that West Elk was following industry standard practices in data collection, and that the data were valid. The gas quality used for design in this report derived from a weighted average of the 6 E Seam MDWs that have flowed in 2009. Arista concludes that the gathering and processing system should be designed to manage CMM with the following composition:

West Elk Mine Gas Analysis	
	E Seam
Methane	55%
Ethane	1.1%
Nitrogen	35%
Oxygen	7.6%
Carbon Dioxide	1.7%

TOTAL E SEAM GAS QUALITY

It is important to note that gas quality varies significantly from MDW to MDW, and even from an individual MDW over time. However, the quality of the combined CMM flows from all six MDWs has consistently remained very close to the chart listed above. While it is uncertain whether this quality will persist from panel to panel, Arista concludes that it is a reasonable baseline on which to design the gathering and processing system.

Detailed Gas Analysis

To finalize and confirm the design, more detailed gas analysis was required, mostly to verify that certain components occasionally found in natural CMM flows were not present, or were below levels that would require additional treatment facilities. Arista directed West Elk personnel to take two gas samples from different MDWs and send them to Analytical Solution, Inc., for extended gas analysis. Because the quality from individual wells can vary so much, we chose two wells to represent extremes of methane content (60% and 35% methane) to analyze the full life cycle of the MDW's. The samples were taken on May 15, 2009 and the final report was released on June 14, 2009. Arista and the vendor of the proposed gas processing equipment reviewed the results.

The first area of focus was sulfur components in the CMM, primarily H2S. Natural gas must have less than 4 parts per million (PPM) H2S to be sold commercially. Both samples came back below 1 PPM, so even if all the oxygen and nitrogen in the CMM is removed, the total H2S would still be below 4 PPM and no additional treatment is required.

The second area of focus were the heavier hydrocarbon components in the CMM, primarily ethane, propane, butanes, pentanes, and hexanes. These are critical, because high levels can create hydrate problems in the compression and pipeline facilities. Moreover, these heavier hydrocarbons can necessitate adjustments in the gas processing equipment to handle any potential natural gas liquids that would be produced. Both samples showed very small amounts of the higher level hydrocarbons, indicating no danger of hydrate formation.

The remaining components were checked to identify any other potential problem components for the gas processing facilities. These results were reviewed by the gas processing equipment vendor, and they concluded that the samples did not indicate any additional or unusual processing concerns.

The detailed gas analysis results can be found in **Appendix B** (page 23)

Basic Gathering System Design

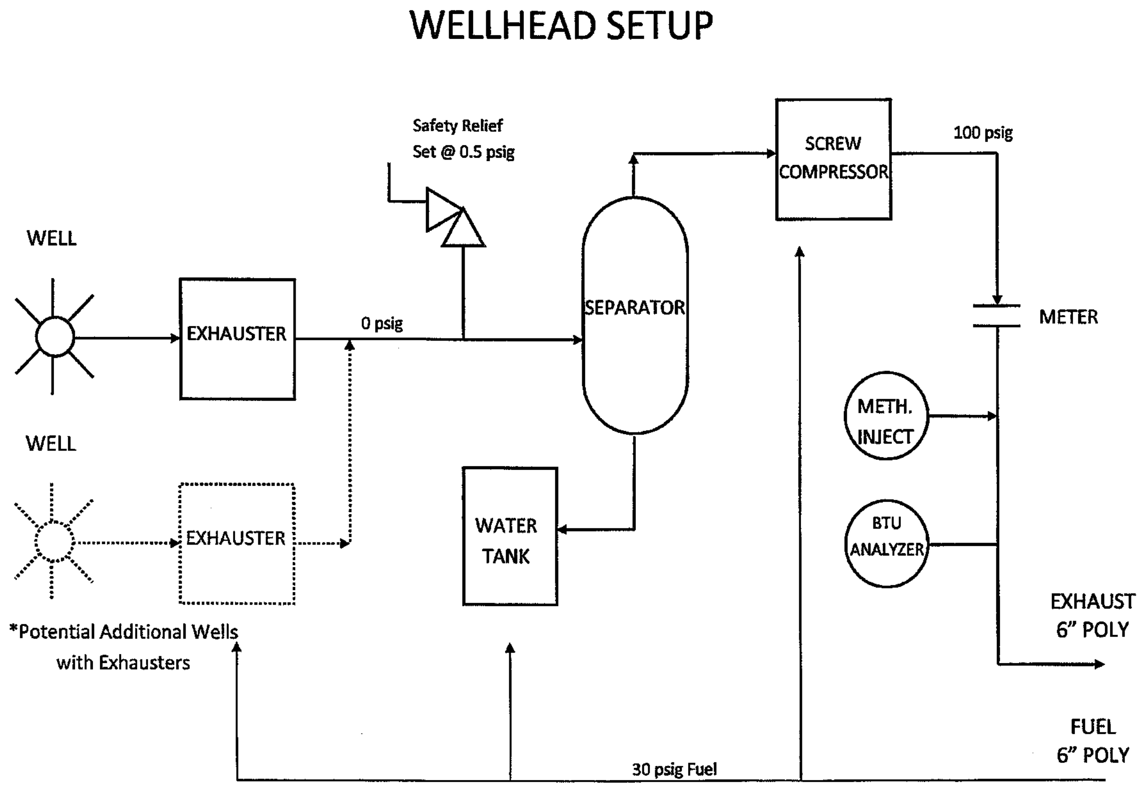
Maps of the proposed gathering system is located in **Appendix C** (page 30)

Overall Philosophy

A gathering system is the only practical and cost effective method to manage E Seam CMM. Any attempt to place disposal or usage equipment (e.g., flares) at individual MDWs would be defeated by the high variability of individual MDW flows and high equipment costs (because of the large number of MDWs). Consequently, the first component of any approach to managing CMM is a gathering system conveying the CMM to a central location.

Generally there are two ways to lay out a gathering system, one with centralized compression and one with remote compression at various inputs to the system. Both have advantages and disadvantages. Arista analyzed both systems. The centralized system would require larger sized pipelines (modeled to be 16" or 20" diameter), which would negatively impact much more of the surface during construction. Another disadvantage to the centralized system is that the panel laterals are very low pressure, which makes it difficult to move condensed liquids in the line. This is made even tougher by the variable terrain which creates low spots for condensed liquids to gather and cold winter temperatures which may cause freezing. Based on the large pipe sizes and potential condensed liquid issues, Arista concluded that the optimum system was to install compression at the each of the wells and use pressure to minimize line sizes. The higher pressure also makes it easier to handle any condensed liquids in the system.

Wellhead Design



WELLHEAD DESIGN SCHEMATIC

Upon analysis, we determined the best course of action is to keep the existing exhausters in service due to the reliable service they have provided. Also the existing exhausters are integral to the approved mine safety plan. The only modification to the existing operation is that we will be providing dehydrated fuel gas for the exhausters, which should further improve their operation.

Picture of existing exhauster

The exhauster will discharge into a piping header that leads to the suction of the screw compressor. There will be a relief valve set to vent all gas from the mine if the screw compressor shuts down for any reason to ensure mine safety. This relief valve will be tied into alarm system and call out will be issued to respond to any compressor malfunction. Also located on the inlet piping header is a separator, which will be tied to a water tank with a gas fired heater. Any condensed liquids will be separated and stored in this tank.

The screw compressor will be designed to operate using the E seam gas (55% methane) as fuel gas. The compressor will have some flexibility to handle fuel gas quality varying from roughly 35% to 70% methane concentrations using its automated air/fuel ratio controller. A gas analyzer will monitor BTU fuel gas quality. If the methane concentration falls between 25% and 35% we will use commercial propane to supplement the fuel gas quality. At concentrations lower than 25% the exhausters would no longer be able to operate so the well would be taken out of service, as is done today. If the concentration is higher than 70% methane the air/fuel ratio would be manually adjusted on the unit by one of the operators. The unit specified for this system is small skid mounted screw compressor package (Cat 3408 driver, Frick NG250 screw). The compressor will be designed to move roughly 1500 mcf/day from 0 psig to 90 psig. The package will include a cooler to lower the gas temperature to below 100 degrees to protect the poly pipe of the lateral and trunk lines. There will be pressure and temperature shutdowns on the compressor to protect the system.

On the discharge header of the screw compressor, we will install a meter, BTU monitor, and a methanol injection pump (with storage tank). This equipment will all be tied into the remote monitoring system, which will allow operators to see current conditions and automatically issue alarms and call-outs as needed.

The fuel for the exhauster and compressor equipment will be taken straight from the header, measured through a meter, and lowered in pressure to roughly 40 psig by fuel regulators. The gas will be dehydrated by running it through a desiccant pipeline dryer manufactured by Van Gas Technologies. This technology minimized emissions and chemical storage on the site. The desiccant is consumed in the process, so there is no waste product. This small unit would need to be filled roughly once a quarter. The exhauster, the screw compressor, the tank heater, and each of these devices are protected with a regulator and relief valve to prevent overpressure.

As the volume of gas drops at each wellhead, it will become necessary to move the screw compressors in order to optimize their performance. The exhauster would continue to operate and would discharge into the existing gathering system, flowing to another wellhead where a screw compressor would be located. We anticipate that up to 4 exhausters could feed a single screw compressor as the system is built out, especially in the sealed panels not associated with longwall mining operation.

Panel Lateral Gathering System

Arista initially proposed a top-of-ground gathering system built with 6" SDR 11 poly pipe laid between each of the MDWs using low impact construction method with narrow right-of-ways and limited tree clearing. This "straight line" lay out would minimize amount of pipe needed and would be relatively easy to install as a minimum number of roads would be impacted. After discussion with the mine operators, Arista decided that this was unreasonable, primarily because the mine has already negotiated corridors for the roads needed to drill and maintain the MDWs. It was unlikely that additional impact would be allowed, so Arista modified the layout of the panel lateral gathering lines to match the surface impact already approved for Mountain Coal's mine operations. In this case, it is assumed that we will lay roughly 50% of this pipe on the surface, primarily next to roads, and that 50% will be buried in the center of the road. The difference between laying in approved corridors verses "straight line" layout is an increase of 15% in length. Because more of the pipe will be buried in the second case, the actual increase in cost is closer to 40%.

SDR11 pipe is designed to have a maximum allowable operating pressure of 120 psig, which will be protected primarily with compressor shut downs set at 110 psig and a secondary relief valve set at 120 psig located on the pig launcher at the trunk line. Poly pipe is much cheaper to purchase and install than steel pipe, and as long as the system is protected from high temperature and pressure, it is very safe and reliable.

The layout of the gathering system includes 34.4 miles of panel laterals.

Panel 1 E Seam MDW's – Shows typical terrain and vegetation

Trunk line

The trunk line will be a 10" SDR11 poly pipeline. The total length of this pipeline will be 8.3 miles from the edge of Panel 8 at the far south end of the mine to the location near the electrical substation where the basic gathering system terminates. Pig launching facilities will be included to allow for the operators to clean the liquids out of the line to keep high performance in the system. The size of the line (10") was chosen to provide roughly 35 psig at the north end of the system near the substation.

Control Equipment

Included in the capital estimates is a gas chromatograph, remote monitoring system, and alarm system. This equipment will primarily be utilized by the operators to remotely monitor the system.

Winter Operations Issues

During winter months, limited access will prevent relocation of the screw compressors and exhausters. Currently the mine has a large enough fleet of exhausters to install one on each of the MDWs they anticipate mining past with the longwall during the winter. This could include up to 10 MDWs in the winter if the mine is in full production. Winter limitations on moving screw processors will require additional wellhead setups to provide adequate coverage. This can be achieved with a combination of three extra screw compressors, along with some temporary 10" top-of-ground pipe located between several of the MDW's. Operations staff would locate the 6 screw compressors (3 for normal longwall panel operation + 3 extra for winter operation) along the panel that is to be mined, roughly spaced one every other MDW. The mine operators would then run temporary 10" pipe from each MDW that does not have a screw compressor to one of the adjacent wells that does. Because the panel gathering lines are not laid out exactly along the individual panels and there may be a midwinter panel transition,, each winter a specific plan will need to be put together to anticipate the upcoming requirements. This type of planning is currently done by the mine operators in the context of exhauster relocation, which is done each fall in anticipation of winter's arrival. For the O&M budget, Arista assumed 6000' of 10" poly would be laid every year and a total of 12 compressor moves would be made each year.

Capital Costs

The basic gathering system includes 8 wellhead setups, 33.9 miles of 6" SDR11 poly panel laterals, and 8.3 miles of 10" SDR11 poly trunk line, and various control equipment identified above. Six of the screw compressors would be used on the current longwall panel, and the other two would be reserved for the sealed panels.

MDW Wellheads	$ 5,991,000
E system Gathering	$ 4,611,655
Control System	$ 405,000
Engineering (10%)	$ 1,001,650
Total Project Cost	$ 12,107,320

This estimate does not include costs associated with permitting these facilities, such as preparation of environmental review documents. These costs are very difficult to estimate without detailed conversations with the various stakeholders but previous projects that Arista has been involved with have had costs for these type of activities of $200,000 or more (up to $1,000,000 in some cases).

Detailed cost estimate for the Basic Gathering System from the MDWs to a substation can be found in **Appendix D** (page 34).

Gathering System O&M Costs

The gathering system Operation and Maintenance ("O&M") will be performed by a staff of 8, including a working supervisor, Instrumentation tech, and 6 mechanic/operators. We assume that the system will be worked with day shifts, seven days a week. Also, for safety reasons, there will always be at least two employees present when working in the field. There will be a callout system for alarms, and employees would rotate call out responsibility. Minor work on compression, pumps, etc would be done by gathering employees, with major work such as compression overalls contracted out. It is assumed that 50,000 gallons of methanol will be used annually during the winter months to prevent freeze ups. It is assumed that this water/methanol mix will be disposed as waste water. The staff will have access to the wellheads during the winter, primarily by snowcats. Finally, the O&M expense budget assumes relocating 6000 feet of temporary poly pipe associated with winter operations and it assumes 12 screw compressor moves annually.

The annual O&M costs for the basic gathering system are estimated to be $ 2,118,000.

Breakout of O&M costs for basic gathering system is located in **Appendix E** (page 39)

CMM Disposal and Usage Options

Arista views the options for CMM management as consisting of a series of subsystems. First, all options require the basic gathering system described in the previous section. Second, all options assume a flare of some type, either as the final disposition of all CMM, or as a safety mechanism for other applications during equipment shutdowns or malfunctions. Third, a power generation component can be added to the gathering system and flare, converting CMM to electricity and using the flare as a backup. Fourth, and alternatively, a gas processing system (again with flare backup) can be installed to process the CMM to pipeline quality, and then a pipeline can be run to one of two natural gas pipelines in the region.

Option 1 – Flare E Seam Gas

Other than venting, flaring is the technically simplest means of disposing of the CMM. Flaring is common in the oil and gas industry, and there are many potentially applicable low impact designs. The principal challenge in adapting a flare for use at an active coal mine is ensuring miner safety and obtaining MSHA approval. Arista contacted a number of vendors regarding potential flare designs. None had installed a flare at an active coal mine, but all stated it should be technically feasible.

In discussions, vendors highlighted several features that could address the West Elk operating environment. These included:

(1) An enclosed design to protect surroundings and personnel;
(2) Stack height of 40-60 feet and at least 10 feet above any surrounding trees/structures;
(3) Detonation arrestors;
(4) High temperature shut down switch to ensure against flashback;
(5) Lightening hardening and grounding;
(6) Location to ensure appropriate distance from the nearest MDWs; and
(7) Equipment to prevent gas ignition from propagating up-pipe.

These flares achieve between 95-98% reduction of methane and are very reliable. The enclosed flare system does not utilize external radiation (open flame) and is comparable to a boiler or process heater. The exhaust gases are vented to atmosphere and the site can be cleared enough to alleviate any concerns about ignition of nearby trees. The biggest concern is the prevention of potential flashback to the mine. The system is designed with multiple safety features to prevent this from happening, including detonation arrestors, high temperature shutdowns, and flash back resistant burners. Although these have not been installed in an active mine, they have operated for many years at refineries, gas plants, and other industrial locations with similar safety concerns.

Arista believes that once these and other measures are deemed adequate to provide an acceptable measure of safety sufficient to obtain eventual MSHA approval of a flare design, installation of a flare will be feasible. Arista cannot predict how long MSHA would take or what field-testing MSHA would require. In the larger context of the gathering system, the cost of the proposed flare itself is approximately $450,000, exclusive of MSHA-required field testing and analysis.

In the event that a flare is intended to be used solely as a backup to a power generation or pipeline sales scenario, and it appears that MSHA approval of a flare design may be protracted, a vent system could be employed as an alternative backup. In that case CMM would be vented rather than flared on the occasion of generation/processing equipment malfunction or shutdown, or excess CMM flow. A vent backup is suboptimal as compared to a flare for a variety of reasons, but could be used to avert a regulatory bottleneck.

Capital costs of a "Flare Only" option are essentially the same as the basic gathering system plus the $450,000 flare cost, for a total of $12.56MM. O&M would be same, at $2.12MM.

Detailed information on the flare can be found in **Appendix F** (page 41).

Capital Costs

$12.56 MM

O&M Costs

$2.12 MM

Alternate Flare Option

The basic flaring design assumes a flare location near existing infrastructure, at a lower elevation and well-removed from the active areas of the E-Seam panels. This has two principal advantages. First, flare equipment at this location can be readily combined with power generation or gas processing equipment to provide CMM management flexibility. Second, the location is more readily accessible to operator crews and because of its distance from active mine workings, is believed to be more likely to meet MSHA requirements. However, if the mine were to commit exclusively to flaring CMM, and could secure MSHA, Forest Service, related permitting requirements, a flare could alternatively be located farther up the mountain, centralized over the E-Seam panels (note that the physical ability to locate the flare in this location does not address its economic feasibility, which is a separate issue). This would reduce the gathering system piping and allow centralized screw compression rather than having the screws located at the MDWs. If the flaring is done above the E-seam mining operations, then there is no need for the trunk line down to the substation location. Some of the panel laterals would need to be upsized from 6" to 10" to minimize pressure loss through the system. The key to this design is that the screw compressors in this option would be configured differently than all of the other options discussed in this report – the system would draw a deep vacuum at the suction of the screw compressor and discharge at much lower pressure by going directly to the flare. Because operation would be at a low vacuum, it is likely there will be higher oxygen content due to fugitive leaks on the compression and possibly on the pipeline system. Leaks on a vacuum system pull air into the system rather than gas escaping to the atmosphere. Consequently, under this approach only 4 screw compressors are needed, half as much as for the basic gathering system design, resulting in significant capital and O&M savings.

Alternate Flare Option Capital and O&M

Capital $9.41MM
O&M $1.50MM annual

A map of the proposed alternate flare system, along with capital and O&M estimates, can be found in **Appendix G**

Option 2 – Power Generation

Power Generation using the CMM from the E seam was identified as a potential use, and Mountain Coal retained Burns & McDonnell to perform the detailed engineering and cost estimates associated with the actual equipment. Arista provided the design of gathering system to bring the gas to the power generation location, which is assumed to be adjacent to the existing substation equipment. Two types of generators are being considered, either reciprocating or turbine driven. This study assumes reciprocating, which allows us to utilize the basic gathering system design and costs. Turbine generation would require a small booster compressor to provide adequate pressure.

Capital Cost

Total capital of the gathering system is estimated to be $12.56MM. This includes 8 well locations, the 6" SDR 11 panel laterals, the 10" SDR 11 trunk line to the Substation, and the flare. This estimate does not include any facilities associated with the power generation. Burns & McDonnell is performing a study on power generation for Mountain Coal and the report from this study will include the additional capital cost associated with this equipment.

O&M cost

Total O&M to operate the gathering system (no power generation included) is roughly $2.12MM annually. This includes 8 employees with trucks, methanol and beads for descant dehydration, maintenance on 8 screw compressors and other associated wellhead equipment, and 20k/month to support a small office. Also included in the O&M expense budget is moving the 6000 feet of poly pipe associated with winter operation and 12 screw compressor moves annually. These same employees could be used to maintain the generators. Burns & McDonnell is performing a study on power generation for Mountain Coal and the report from this study will include the additional O&M cost associated with this equipment.

Cost estimates (capital and O&M) for the power generation option can be found in Burns & McDonnell's report.

Option 3 - Processing and Sale of the E Seam Gas

The scope of this option includes a Gathering System, a Gas Processing Unit, and transmission to a natural gas pipeline. The Gas Processing Unit includes compressing the gas for preparation for processing, processing the gas to sales quality, compressing the sales gas, and transporting the sales gas to the nearest pipeline for commercial sales.

Gas Processing Unit

Arista compared a variety of processing units for processing effectiveness and cost before selecting the proposed design. The evaluation started with a gas analysis provided by Mountain Coal. The Gas Analysis provides a list of components in the gas being produced by the mine.

West Elk Mine Gas Analysis	
	E Seam
Methane	55%
Ethane	1.1%
Nitrogen	35%
Oxygen	7.6%
Carbon Dioxide	1.7%

There are a variety of processing units which can be applied to treat the unprocessed gas that will produce pipeline quality gas. While each pipeline company establishes the specific quality they will accept based on the design of their system, for the most part they are very similar. Typical limits include:

Water vapor less than 6 pounds per million cubic feet
Hydrogen Sulfide less than .25 grains per 100 cubic feet (4 parts per million or ppm)
Total sulfur less than 5 grains per 100 cubic feet (20 ppm)
Oxygen less than 10 ppm
Hydrocarbon dewpoint less than 15 degree Fahrenheit
Carbon Dioxide less than 2% by volume

The raw gas for the mine contains the following components that need to be removed or limited - Oxygen (O_2), Carbon Dioxide (CO_2), Water and Nitrogen (N_2). Removal is necessary for the following reasons:

- Oxygen - can cause various problems including degradation of process chemicals (example - amine) and increase corrosion in the pipeline. To prevent this the pipeline specification for oxygen is normally set at 10 ppm or below.
- Carbon Dioxide and Nitrogen - are considered inert gases, which mean they do not burn and will reduce the BTU value of the sales gas. In addition, carbon dioxide in higher quantities and in the presence of water can create acids that are corrosive to pipelines.
- Water - can cause various problems including freezing and increased corrosion.

The proposed design begins with the removal of oxygen from the gas stream. Because of the high amount of oxygen in the West Elk gas stream, Arista concluded that a catalytic process is the only appropriate oxygen removal technology. There are other technologies to remove lower quantities of oxygen, but the West Elk stream's oxygen content is well above their capability. Oxygen removal must take place in the first unit of the processing sequence because carbon dioxide and water are by-products of the oxygen removal process. As a result, the percentage of carbon dioxide and water in the raw gas stream will increase when the oxygen is removed, and these products are themselves contaminants that must later be removed from the gas stream.

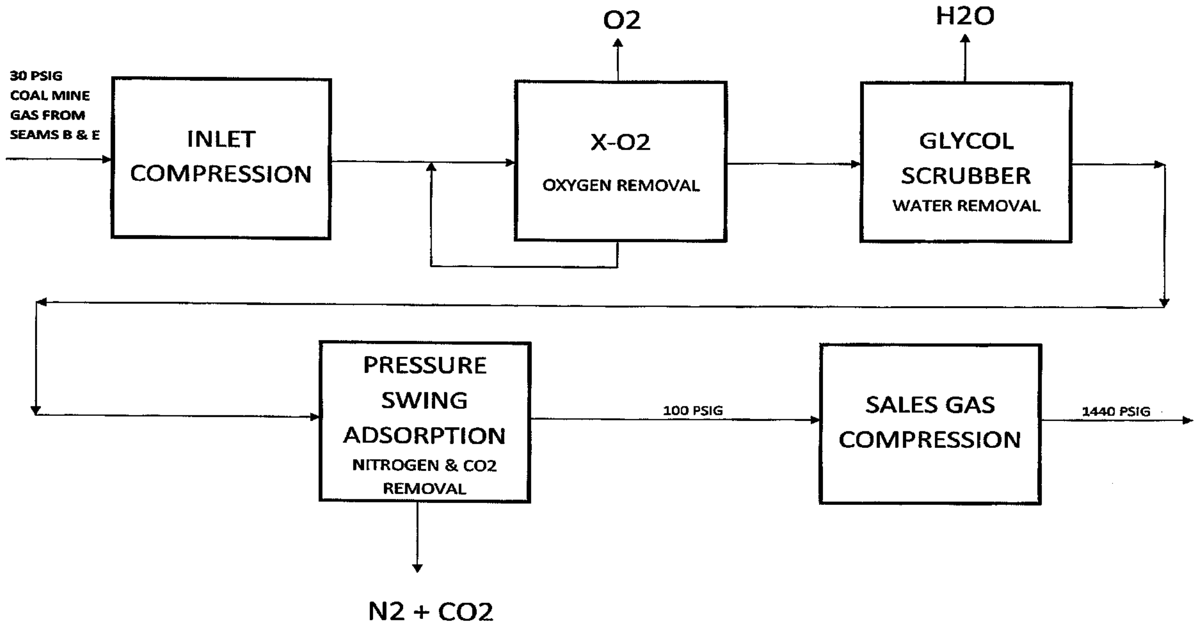
Two basic approaches were evaluated for removal of water, nitrogen, and carbon dioxide. Each approach would work and has its own advantages and disadvantages.

The first approach involves removing the carbon dioxide using an amine chemical absorption process, followed by a molecular sieve to remove the water, and finally through a cryogenic nitrogen removal system. In the chemical absorption process, carbon dioxide is recovered in an amine water solution and is removed from the gas stream. The molecular sieve is an adsorption process that removes water vapor from the gas to very low levels. This is necessary because the cryogenic nitrogen removal system cools the gas to very cold temperatures (-250 degrees Fahrenheit) which would cause any remaining water to freeze and disable the cryogenic system. The main advantage of this approach is that there is very little incidental loss of the methane in the gas stream. The primary disadvantage is that is significantly more expensive than the second approach that was evaluated.

The second approach involves removing the water vapors first, using a glycol scrubbing system. The glycol system is not as effective in water removal as the molecular sieve, but still allows pipeline gas quality specs to be made. Next, the nitrogen and carbon dioxide are removed with a pressure swing adsorption process (PSA). The adsorbent that would be used would remove both the carbon dioxide and nitrogen, but 10% of the methane in the gas stream would be lost to the waste stream that would be sent to the flare for combustion. This incidental loss of methane sales gas is the primary disadvantage of the second process approach. The primary advantage is that capital and operating cost are lower.

The selection of processing approach generally comes down to simple economics. If the total unprocessed stream is less than 2 mmcf/day the PSA option is always the more economic choice. Above 10 mmcf/day the Cryogenic plant is always more economic. Between 2 mmcf/day and 10 mmcf/day, where our design lies, an evaluation is done based on loss of methane (10%) for the PSA process versus the increased capital and operating cost associated with the cryogenic process. Our analysis showed the PSA system was significantly more cost effective. Because the waste stream, including the lost 10% methane is destroyed in the flare, there is no additional environmental impact from this process.

PLANT SCHEMATIC



Plant Discharge and Sales Gas Line

Arista researched the different options for delivery of gas to commercial markets. Two pipeline systems were considered - Bull Mountain and Rocky Mountain Natural Gas (RMNG). Both systems have capacity for additional gas, so the main decision points were the cost to connect and relative surface disturbance associated with the two connections.

RMNG has an 8" pipeline near Austin, Colorado, which would involve laying a 36 mile pipeline. There are closer lines, but they are all distribution lines and have insufficient capacity for the volume of gas requiring delivery. RMNG has a low Maximum Allowable Operating Pressure (550 psig), which means that less compression horsepower and associated capital will be required at the gas plant.

On the Bull Mountain system, the sales lateral would tie-in to a new lateral scheduled to be completed in September 2009 and which lies almost directly north of the West Elk Mine. The tie in location is about 15 miles away, which is significantly closer than RMNG. The operating pressure of the line is going to be around 900 psig, but the incremental cost for additional compression is much less than the capital associated with the extra pipe over to RMNG. If interconnected and supplying gas to Bull Mountain, Mountain Coal may even be able to get a slight price premium due to the low carbon dioxide of their gas compared to the other gas expected to flow on the system.

For these reasons, the Bull Mountain connection is clearly superior from a cost perspective. Because of the shorter connection distance, the Bull Mountain option would also involve less surface disturbance. While a full surface disturbance analysis would also require an examination of the type and sensitivity of impacted terrain, this was beyond the scope of Arista's assignment.

Maps showing the two potential sales laterals can be found in **Appendix C** (page 30).

Sales Gas Quantity

Average input volume of 4.0 MMCF/day of raw CMM gas equates to 2.2 MMCF/day of Methane. The field compression and exhausters will burn roughly .35 MMCF/day in fuel. This means we have around 1.85 MMCF/day of Methane entering the plant. Normal losses and fuel use in the plant would use about .1MMCF/day so that we will have 1.75 MMCF/day available for sales.

We assumed that a majority of the plant equipment and discharge compression would be electric in this design.

Capital Costs

The basic gathering system to the substation location, including the flare, is estimated to cost $12.56 MM. The plant, final high pressure compression, and associated equipment are estimated to cost $12.1 MM. The sales lateral to Bull Mountain is estimated to cost $10.5MM. Total capital cost for this project is estimated to be $35.4MM

Detailed cost estimate for the gas sales option can be found in **Appendix H** (page 57).

O&M Costs

In addition to the O&M costs associated with the basic gathering system ($2.12MM annual) costs need to be added for the gas plant ($700,000 annual), compression ($150,000 annual), and the pipeline to Bull Mountain ($100,000 annual).

Total O&M is estimated to be roughly $3,100,000 annually.

Detailed O&M estimate for the sales gas option can be found in **Appendix I** (page 61).

APPENDIX INDEX

Appendix A

Arista Information and Qualifications

Arista Midstream Services, LLC

Led by a team of seasoned professionals, Arista provides oil and gas producers with a full complement of midstream services. Capabilities include the gathering, treating and handling of natural gas, crude oil, water and condensates, and carbon dioxide sequestration. We are grounded in three bedrock concepts: superior customer service, strong relationships, and the delivery of all-in solutions. We believe that good business is always built on good relationships: relationships with our customers, local communities, landowners, regulatory agencies, and our environment.

Our Capabilities

Arista has expanded the traditional definition of midstream to provide customers with comprehensive, all-in solutions and opportunities for growth. Core capabilities include the gathering, treating and handling of natural gas, crude oil and condensates, flowback and produced water, and carbon dioxide sequestration. We are focused on building strong, open relationships with our customers and all of the constituents in the value chain.

Natural Gas

Arista's origins are in natural gas gathering and processing. We are experts at gathering in the Rocky Mountains where large blocks of federal lands, environmentally sensitive areas, and split estates present unique challenges. We are also experts at gathering gas from actively developing resource plays, and unconventional gas and coalbed methane reservoirs which are expected to deliver an increasing share of domestic gas supplies. Additional services include the recovery, transport and sequestration of carbon dioxide to enhance oil recovery operations and reduce the emission of greenhouse gas. We understand how to build pipelines and plants and the importance of meeting development schedules. We work hard to address our customers' critical business concerns.

Water

The effective management of produced and flowback water creates cost savings, sustainable operating solutions in the field, and vehicles for creating value. Water is a scarce resource in the Rocky Mountains. Arista's ability to recover and maximize the use of distilled water, hydrocarbons and methanol from produced water creates substantial cost savings in trucking and disposal without capital expense. Arista's all-in water management solutions also mitigate the environmental impact of operations and create a net gain in water for the arid areas in the West.

Crude Oil and Condensates

Arista provides gathering, treating and handling services for crude oil and condensates. We build and operate gathering infrastructure and terminal facilities to aggregate and move condensate and crude oil to market. Broad and exceptional service is baseline at Arista. Our pipeline, trucking, terminal and storage capabilities give us the capacity to deliver an array of integrated, value-added services of the highest quality. We recognize that our customers count on us to supply reliable, cost effective solutions. They depend on it. The country's energy requirements depend on it. And we deliver.

Management

Carter G. Mathies, Chairman and Director. Mr. Mathies was previously the Chairman and Co-Founder of Slater River Resources, a privately held E&P company. Previously, Mr. Mathies was Vice President and Western Division Manager of Westport Resources Corporation prior to their merger with Kerr McGee, Vice President of the midstream group of Kinder Morgan, Inc. and President and CEO of Tipperary Corporation a publicly held exploration and production company. Mr. Mathies has a long history of advising Indian tribes in the Rocky Mountain Region on development of their natural resources. Mr. Mathies is a past President and current board member of the Independent Producers Association of Mountain States (IPAMS).

Steven B. Huckaby, the President of Arista, has a quarter century of experience in the midstream gas gathering and processing industry. Most recently, Mr. Huckaby served as Vice President of Business Development and General Manager of the Denver office of Momentum Energy Group, LLC. He has also served as Vice President of the midstream group of Kinder Morgan, Inc., Executive Vice President and Co-Founder of Bear Paw Energy, Inc. and Vice President and COO of Vessels Oil & Gas, Inc. Mr. Huckaby has held various business development, operations and engineering positions with Snyder Oil and Oxy/Cities Service Oil & Gas.

Tim Pimmel, Vice President of Engineering and Operations. Mr. Pimmel is responsible for all Arista asset construction and operations. Prior to joining Arista, Tim served as Vice President of Operations of the Gathering Unit at PRB Energy. In this position, he was responsible for all facets of the midstream business. Mr. Pimmel was with Bear Paw Energy, LLC from 2000 to 2005, last serving as Operations Director. Primary responsibilities were managing the operations of assets in Powder River and Williston Basins. From 1998 to 2000, Mr. Pimmel worked with Kinder Morgan in the Denver Office, primarily as a facility planning engineer. From 1990 to 1998, he worked for Natural Gas Pipeline Company of America as a Field Engineer on numerous construction projects.

Appendix 2

Extended Gas Analysis Report

ANALYTICAL SOLUTION, INC. (AnSol)

6/14/09

Analytical Report

Sample log # : J0519a.doc

Purchase Order #:	*WEMC-G-WE1SLJ*	Customer Project:	
Company :	***Mountain Coal Company***	Requester :	***Steve Woods*** ***Somerset Laboratory***
Address :	*5174 Hwy 133* *Somerset, CO 81434*	Phone:	*970-929-5022*
		Fax:	
		E-mail :	
Sample Description :	*Coal bed methane*	Received Date :	*5/19/09*
Number of Samples :	*2*	Total Report Page:	*6*

Note: This report is submitted to the requester through E-mail only. Please let us know if your need this document security signed, or a hard copy report by mail or fax.

Report Summary:

Results are tabulated in the following pages.

Submitted by: Sherman S. Chao, Ph.D.

Tel: (630) 230-9378, Fax: (630) 230-9376

ANALYTICAL SOLUTION, INC. **(AnSol)**

6/14/09

Analytical Report

Sample log # : J0519a.doc

GAS COMPONENT ANALYSIS

Sample ID:	**Conc. Unit**	**J0519a01**	**J0519a02**
		Gas, V18-E1-38, 5/15/09, 0851	Gas, V14-E1-42, 5/15/09, 0840
Methane	%	60.7	34.5
Carbon dioxide	%	1.50	2.30
Nitrogen	%	28.9	50.5
Oxygen	%	7.8	11.9
Ethane	%	0.91	0.62
Propane	%	0.177	0.106
i-Butane	%	0.023	0.027
n-Butane	%	0.028	0.023
i-Pentane	%	0.0129	0.0094
n-Pentane	%	0.0050	0.0038
Hexane +	%	0.0232	0.007
GHV, dry (14.73 psi) *	Btu/scf	639	366
Relative density *		0.739	0.856
NMHC (Non-Methane Hydrocarbons)	% C	1.376	0.893
	mg/M^3	0.697	0.453
Total Sulfur	ppmv	0.65	0.192
	mg/M^3	0.84	2.60
Total organic silicon	ppmv	0.22	0.19
	mg/M^3	0.26	0.23
Total organic chlorine	ppmv	<0.10	<0.10
	mg/M^3	<0.15	<0.15
Total organic fluorine	ppmv	<0.1	<0.1
	mg/M^3	<0.08	<0.08

* **Calculation** based on 4 major components. 60°F-14.73 psi

Note: All major component concentrations were reported as a moisture, H_2S free basis and were normalized to 100%. Oxygen and Argon cannot be separated; therefore, the oxygen result includes a small amount of Argon. Some results may be reported with additional significance for reference.

Analytical Solution, Inc., 7320 S. Madison, Unit 500, Willowbrook, Illinois 60527

Compound Speciation - Siloxanes

	J0519a01		J0519a02	
	Gas, V18-E1-38, 5/15/09, 0851		Gas, V14-E1-42, 5/15/09, 0840	
Organic Silicon (siloxanes)	ppmv as Si	ppmv	ppmv as Si	ppmv
Tetramethyl silane	<0.1	<0.1	<0.1	<0.1
Trimethyl silanol	<0.1	<0.1	<0.1	<0.1
Hexamethyldisiloxane (L2)	<0.1	<0.05	<0.1	<0.05
Hexamethylcyclotrisiloxane (D3)	0.06	0.019	0.03	0.010
Octamethyltrisiloxane (L3)	<0.1	<0.033	<0.1	<0.033
Octamethylcyclotetrasiloxane (D4)	0.07	0.018	0.07	0.017
Decamethyltetrasiloxane (L4)	<0.1	<0.025	<0.1	<0.025
Decamethylcyclopentasiloxane (D5)	0.04	0.008	0.05	0.010
Dodecamethylpentasiloxane (L5)	<0.1	<0.02	<0.1	<0.02
Dodecamethylcyclohexasiloxane (D6)	<0.1	<0.017	<0.1	<0.017
Others (as L2)	0.05	0.025	0.04	0.02
Total:	0.22		0.19	
Total (Si, mg /M^3):	0.26		0.23	

Note: Some results may be reported with additional significance for reference. The normal detection limit is 0.1 ppmv Si.

Special Note: It is known that some sample bag use light lubricant at sample valves. The low level of siloxanes found in the sample may come from lubricant.

Compound Speciation – Sulfur Components

Sulfur Compounds, ppmv as S	**J0519a01**	**J0519a02**
	Gas, V18-E1-38, 5/15/09, 0851	Gas, V14-E1-42, 5/15/09, 0840
Hydrogen sulfide	0.16	0.23
Carbonyl sulfide	0.46	1.69
Methyl mercaptan	<0.05	<0.05
Ethyl mercaptan	<0.05	<0.05
Dimethyl sulfide	<0.05	<0.05
Carbon disulfide *	<0.05	<0.05
i-Propyl mercaptan	<0.05	<0.05
t-Butyl mercaptan	<0.05	<0.05
n-Propyl mercaptan	<0.05	<0.05
Ethyl methyl sulfide	<0.05	<0.05
Thiophene	<0.05	<0.05
Diethyl sulfide	<0.05	<0.05
Dimethyl disulfide *	<0.05	<0.05
Ethyl methyl disulfide *	<0.05	<0.05
Diethyl disulfide *	<0.05	<0.05
Others (as S)	<0.05	<0.05
Total S:	0.65	1.92

Note: Some results were reported with additional significance for reference. The normal detection limit of each sulfur compound is 0.1 ppmv.

* 1.0 ppmv as sulfur = 0.50 ppmv sulfur compound

Sample ID: Gas, V18-E1-38, 5/15/09, 0851

Target VOC	ppmv	Target VOC	ppmv
Dichlorodifluoromethane	<0.10	cis-1,3-Dichloropropene	<0.10
Chloromethane	<0.10	Methyl butyrate	<0.10
1,2-Dichloro-1,1,2,2-tetrafluoroethane	<0.10	4-methyl-2-pentanone (MIBK)	<0.10
Vinyl chloride	<0.10	Trans-1,3-Dichloropropene	<0.10
Bromomethane	<0.10	Methylcyclohexane	26.3
Chloroethane	<0.10	1,1,2-Trichloroethane	<0.10
Ethanol	<0.10	2,3,4-Trimethyl pentane	0.25
i-Pentane	129	Toluene	0.29
Acetone	<0.10	Chlorodibromomethane	<0.10
Fluorotrichloromethane	<0.10	2-Methyl heptane	3.7
2-propanol	<0.10	3-Methyl heptane	2.51
n-Pentane	51	Ethyl butyrate	<0.10
Bromoethane	<0.10	1,2-Dibromoethane	<0.10
1,1-Dichloroethene	<0.10	Propyl propanoate	<0.10
Methyl acetate	<0.10	Butyl acetate	<0.10
Methylene chloride	<0.10	n-Octane	3.11
3-Chloropropene	<0.10	Tetrachloroethene	<0.10
2,2-dimethylbutane	<0.10	Chlorobenzene	<0.10
1,1,2-Trichloro,1,2,2-trifluroethane	<0.10	Ethylbenzene	0.10
n-Propanol	<0.10	m,p-Xylene	0.20
Trans-1,2-dichloroethene	<0.10	Propyl butyrate	<0.10
1,1-Dichloroethane	<0.10	Bromoform	<0.10
Methyl tert-butyl ether	<0.10	Styrene	<0.10
2-Methyl pentane	34	1,1,2,2-Tetrachloroethane	<0.10
Methy ethyl ketone (MEK)	<0.10	o-Xylene	<0.10
3-Methyl pentane	23.7	n-Nonane	0.94
2-Butanol	<0.10	Alpha pinene	<0.10
cis-1,2-dichoroethene	<0.10	n-Propyl benzene	<0.10
Ethyl acetate	<0.10	3-Ethyl toluene	<0.10
n-Hexane	26.6	4-Ethyl toluene	<0.10
Chloroform	<0.10	1,3,5-Trimethylbenzene	<0.10
Iso butyl alc.	<0.10	Butyl butyrate	<0.10
Tetrahydrofuran	<0.10	2-Ethyl toluene	<0.10
1,2-Dichloroethane	<0.10	1,2,4-Trimethylbenzene	<0.10
1,1,1-Trichloroethane	<0.10	n-Decane	0.18
1-Butanol	<0.10	1,3-Dichlorobenzene	<0.10
Benzene	0.68	Benzyl chloride	<0.10
Carbon tetrachloride	<0.10	1,2-Dichlorobenzene	<0.10
Cyclohexane	12.8	Delta-carene/Alpha-terpinene	<0.10
2-Methyl hexane	9.4	Cymenes	<0.10
3-Methyl hexane	11.6	Limonene	<0.10
1,2-Dichloropropane	<0.10	1,4-Dichlorobenzene	<0.10
Bromodichloromethane	<0.10	Undecane	0.61
Trichloroethene	<0.10	1,2,4-Trichlorobenzene	<0.10
2,2,4-trimethylpentane/2,2-dimethylhexai	5.6	Dodecane	<0.10
Ethyl propionate	<0.10	Naphthalene	<0.10
Propyl acetate	<0.10	Hexachloro-1,3-butadiene	<0.10
n-Heptane	11.6	Hexachloroethane	<0.10

Note: TO-17 test. The test results include all TO-14A, some TO-15 and most common compounds in BioGas. Additional significance may be reported for reference only. Detection limit higher than the normal 0.1-0.2 ppmv is primarily due to the broad peak shape and closely eluted unknown compound with larger concentration.

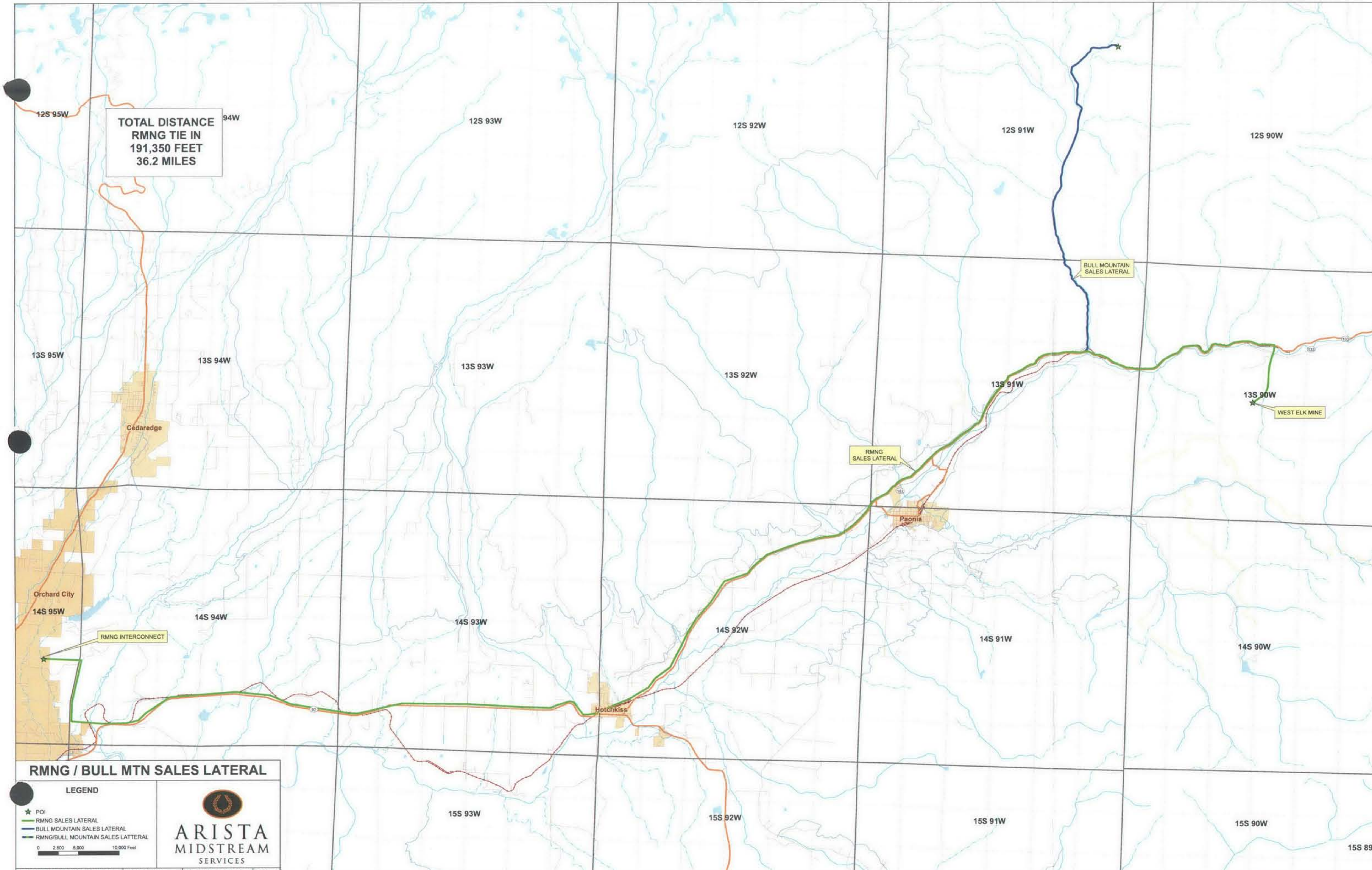
Sample ID: Gas, V14-E1-42, 5/15/09, 0840

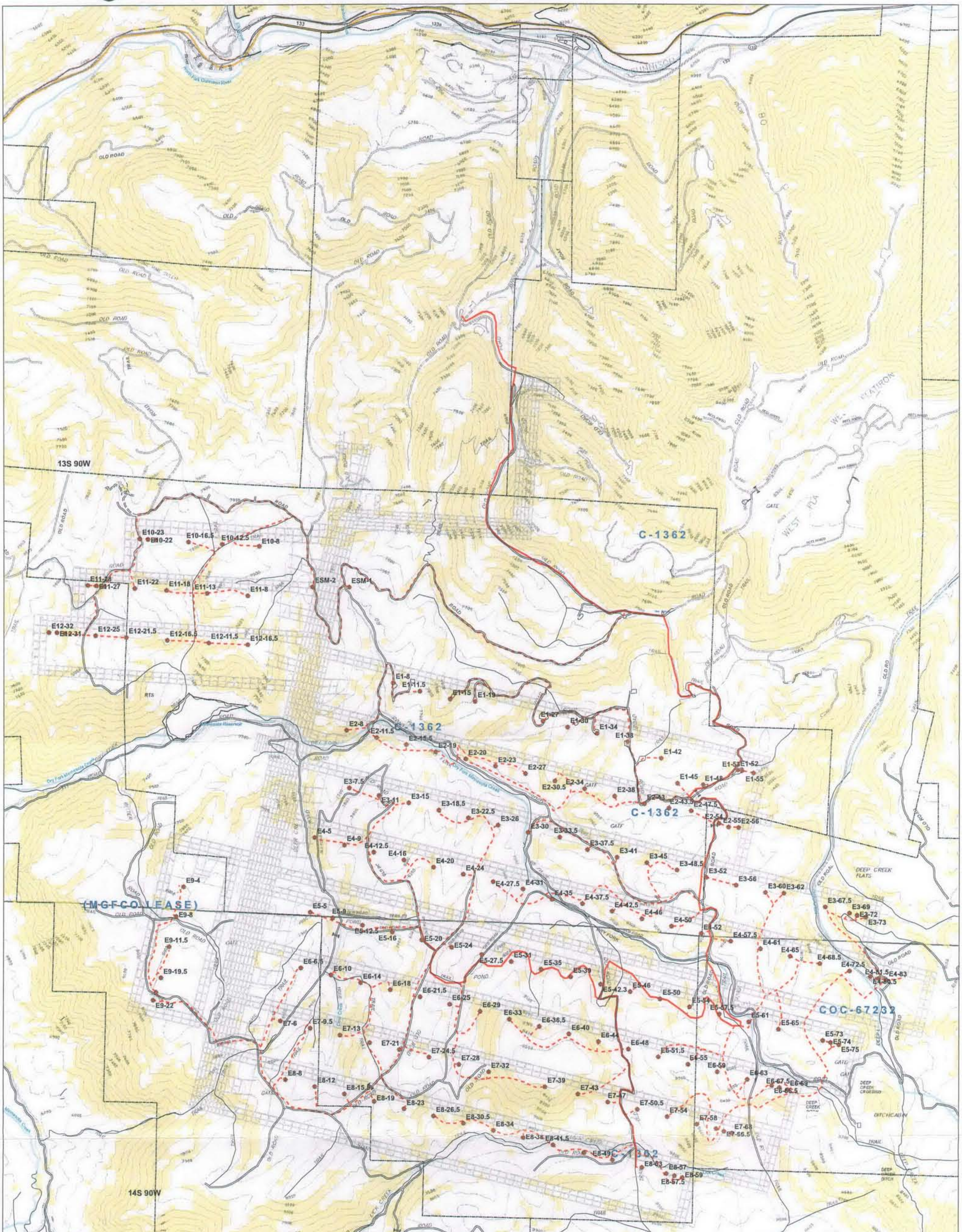
Target VOC	ppmv	Target VOC	ppmv
Dichlorodifluoromethane	<0.10	cis-1,3-Dichloropropene	<0.10
Chloromethane	<0.10	Methyl butyrate	<0.10
1,2-Dichloro-1,1,2,2-tetrafluoroethane	<0.10	4-methyl-2-pentanone (MIBK)	<0.10
Vinyl chloride	<0.10	Trans-1,3-Dichloropropene	<0.10
Bromomethane	<0.10	Methylcyclohexane	9.5
Chloroethane	<0.10	1,1,2-Trichloroethane	<0.10
Ethanol	<0.10	2,3,4-Trimethyl pentane	0.16
i-Pentane	94	Toluene	0.20
Acetone	<0.10	Chlorodibromomethane	<0.10
Fluorotrichloromethane	<0.10	2-Methyl heptane	1.84
2-propanol	<0.10	3-Methyl heptane	1.16
n-Pentane	38	Ethyl butyrate	<0.10
Bromoethane	<0.10	1,2-Dibromoethane	<0.10
1,1-Dichloroethene	<0.10	Propyl propanoate	<0.10
Methyl acetate	<0.10	Butyl acetate	<0.10
Methylene chloride	<0.10	n-Octane	1.21
3-Chloropropene	<0.10	Tetrachloroethene	<0.10
2,2-dimethylbutane	<0.10	Chlorobenzene	<0.10
1,1,2-Trichloro,1,2,2-trifluroethane	<0.10	Ethylbenzene	<0.10
n-Propanol	<0.10	m,p-Xylene	0.11
Trans-1,2-dichloroethene	<0.10	Propyl butyrate	<0.10
1,1-Dichloroethane	<0.10	Bromoform	<0.10
Methyl tert-butyl ether	<0.10	Styrene	<0.10
2-Methyl pentane	20.0	1,1,2,2-Tetrachloroethane	<0.10
Methy ethyl ketone (MEK)	<0.10	o-Xylene	<0.10
3-Methyl pentane	12.5	n-Nonane	0.33
2-Butanol	<0.10	Alpha pinene	<0.10
cis-1,2-dichoroethene	<0.10	n-Propyl benzene	<0.10
Ethyl acetate	<0.10	3-Ethyl toluene	<0.10
n-Hexane	13.2	4-Ethyl toluene	<0.10
Chloroform	<0.10	1,3,5-Trimethylbenzene	<0.10
Iso butyl alc.	<0.10	Butyl butyrate	<0.10
Tetrahydrofuran	<0.10	2-Ethyl toluene	<0.10
1,2-Dichloroethane	<0.10	1,2,4-Trimethylbenzene	<0.10
1,1,1-Trichloroethane	<0.10	n-Decane	<0.10
1-Butanol	<0.10	1,3-Dichlorobenzene	<0.10
Benzene	0.49	Benzyl chloride	<0.10
Carbon tetrachloride	<0.10	1,2-Dichlorobenzene	<0.10
Cyclohexane	6.8	Delta-carene/Alpha-terpinene	<0.10
2-Methyl hexane	5.3	Cymenes	<0.10
3-Methyl hexane	6.2	Limonene	<0.10
1,2-Dichloropropane	<0.10	1,4-Dichlorobenzene	<0.10
Bromodichloromethane	<0.10	Undecane	<0.10
Trichloroethene	<0.10	1,2,4-Trichlorobenzene	<0.10
2,2,4-trimethylpentane/2,2-dimethylhexa	2.57	Dodecane	<0.10
Ethyl propionate	<0.10	Naphthalene	<0.10
Propyl acetate	<0.10	Hexachloro-1,3-butadiene	<0.10
n-Heptane	5.3	Hexachloroethane	<0.10

Note: TO-17 test. The test results include all TO-14A, some TO-15 and most common compounds in BioGas. Additional significance may be reported for reference only. Detection limit higher than the normal 0.1-0.2 ppmv is primarily due to the broad peak shape and closely eluted unknown compound with larger concentration.

Appendix C

System Maps


TOTAL DISTANCE
RMNG TIE IN
191,350 FEET
36.2 MILES
12S 95W
94W
12S 93W
12S 92W
12S 91W
12S 90W
BULL MOUNTAIN
SALES LATERAL
13S 95W
13S 94W
13S 93W
13S 92W
13S 91W
13S 90W
WEST ELK MINE
Cedaredge
RMNG
SALES LATERAL
Paonia
Orchard City
14S 95W
14S 94W
14S 93W
14S 92W
14S 91W
14S 90W
RMNG INTERCONNECT
Hotchkiss
15S 93W
15S 92W
15S 91W
15S 90W
15S 89W
RMNG / BULL MTN SALES LATERAL
LEGEND
POI
RMNG SALES LATERAL
BULL MOUNTAIN SALES LATERAL
RMNG/BULL MOUNTAIN SALES LATTERAL
0 2,500 5,000 10,000 Feet
ARISTA
MIDSTREAM
SERVICES
DRAWN BY:RCL CONSULTING INC.
DATE:9/22/09
FILE: WEM-RMNG-81009
REV: A



WEST ELK MINE (E SEAM)
LEGEND
MDW WELLS
ACCESS ROADS
OTHER ROADS
GATHERING LINE
TRUNK LINE
SLOPES > 60 DEGREES
ARISTA
MIDSTREAM
SERVICES
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DATE: 9/8/09
FILE: WEM-22609
REV: C
C-1362
COC-67232
(MGFCO LEASE)
13S 90W
14S 90W


11S 91W
11S 90W
BULL MOUNTAIN INTERCONNECT
12S 91W
12S 90W
BUCK MESA
GUNNISON NATIONAL
FOREST
Fire Mountain
Thousand Acre Flats
NORTH FORK
GUNNISON RIVER
13S 91W
13S 90W
SUBSTATION
WEST ELK MINE
Jumbo Mountain
TOTAL DISTANCE
BULL MOUNTAIN LINE TIE IN
78,347 FEET
14.8 MILES
BULL MOUNTAIN SALES LATERAL
LEGEND
POI
WEST ELK MINE GATHERING
BULL MOUNTAIN SALES LINE
0
1,500
3,000 Feet
ARISTA
MIDSTREAM
SERVICES
DRAWN BY: RCL CONSULTING INC.
DATE: 8/10/09
FILE: WEM-22609
REV: B

Appendix D

Cost Estimate for Basic Gathering System

West Elk Gas Gathering System
E SEAM BASIC GATHERING

MDW wellheads	$	5,991,000
E System Gathering	$	4,610,655
Control System	$	405,000
Engineering (10%)	$	1,100,665
TOTAL PROJECT COST	**$**	**12,107,320**

West Elk Mine
MDW Wellheads

Description	Quantity	Units	Unit Cost	Total Cost	CATEGORY TOTAL
Material					
Exhauster	Already Owned, no additional capital				
Relief Valve	1	lot	$ 15,000	$ 15,000	
Separator	1	lot	$ 25,000	$ 25,000	
Water Tank w/heater	1	lot	$ 20,000	$ 20,000	
Screw Compressor	1	lot	$ 380,000	$ 380,000	
Fuel Conditioning System	1	lot	$ 15,000	$ 15,000	
Meter Skid w/efm	1	lot	$ 30,000	$ 30,000	
Methanol injection	1	lot	$ 5,000	$ 5,000	
BTU Monitoring	1	lot	$ 10,000	$ 10,000	
Sat. Communications	1	lot	$ 10,000	$ 10,000	
Misc valves, fittings, pipe	1	lot	$ 7,500	$ 7,500	
Total Material					$ 517,500
Installation					
Exhauster	Already estimated in Arch budgets				
Screw Compressor	1	lot	$ 75,000	$ 75,000	
Well Head Equipment	1	lot	$ 50,000	$ 50,000	
Total Installation					$ 125,000
Project Management					
Engineering included in Roll Up					
Inspection	10	days	$ 1,000	$ 10,000	
Contingency	15	%	$ 642,500	$ 96,375	
Total Project Management					$ 106,375
TOTAL COST PER WELL					**$ 748,875**
Number of wells	**8**		**3 wells on longwall panel, 3 for winter operation on longwall, 2 wells on sealed panels**		
TOTAL PROJECT COST					**$ 5,991,000**

West Elk Mine
"E" Seam Gathering

Description	Quantity	Units	Unit Cost	Total Cost	CATEGORY TOTAL
Material					
10" SDR 11 Poly	46072	ft	$ 3.89	$ 179,220	
10" SDR 11 Poly - Winter Temp	6000	ft	$ 3.89	$ 23,340	
6" SDR 11 Poly	188218	ft	$ 1.48	$ 278,562	
Valves	1	lot	$ 100,000	$ 100,000	
12" pig traps	3	each	$ 60,000	$ 180,000	
Total Material					**$ 761,122**
Installation					
10" SDR 11 (per Petty quote)	46072	ft	$ 23	$ 1,036,618	
10" Poly - temp top of ground	6000		$ 20	$ 120,000	
8" SDR 11 (per Petty quote)	188218	ft	$ 10	$ 1,882,178	
Pig Traps	3	each	$ 35,000	$ 105,000	
Total Installation					**$ 3,143,795**
Project Management					
Engineering included in Roll Up					
Inspection	120	days	$ 1,000	$ 120,000	
Contingency	15	%	$ 3,904,917	$ 585,738	
Total Project Management					**$ 705,738**
TOTAL PROJECT COST					**$ 4,610,655**

West Elk Mine
Control System

Description	Quantity	Units	Unit Cost	Total Cost	CATEGORY TOTAL
Material					
Chromatograph	1	lot	$ 75,000	$ 75,000	
Control Valves	1	lot	$ 75,000	$ 75,000	
Alarm Callout System	1	lot	$ 15,000	$ 15,000	
SCADA System	1	lot	$ 50,000	$ 50,000	
Gen Dehy	1	lot	$ 40,000	$ 40,000	
Total Material					**$ 255,000**
Installation					
Chromatograph	1	lot	$ 25,000	$ 25,000	
Control Valves/flare	1	lot	$ 50,000	$ 50,000	
Gen Dehy	1	lot	$ 25,000	$ 25,000	
SCADA/Alarm	1	lot	$ 50,000	$ 50,000	
Total Installation					**$ 150,000**
TOTAL PROJECT COST					**$ 405,000**

Appendix E

O&M Cost for Basic Gathering System

West Elk Mine O&M
Basic Gathering System
E Seam

					COST
Labor	# emp.	base	w/30% load		
Supervisor	1	100000	130000		
I&E Tech	1	80000	104000		
Mechanic/Operator	6	70000	546000		
				$	780,000.00
Trucks	6	(1500/month)		$	108,000.00
Methanol	50000	gallons		$	150,000.00
Compression	# units	hp	$100/hp		
working screws	6	400	240000		
sealed screws	2	400	80000		
				$	320,000.00
Winter Operations					
Move Screws	12	25000	300000		
Move 10" temp poly	6000	20	120000		
				$	420,000.00
Measurement/Scada	# meters	10000/yr			
working screws	6	60000			
sealed screws	2	20000			
System	2	20000			
				$	100,000.00
Office/Misc	12	months @ 20k each		$	240,000.00
TOTAL				**$**	**2,118,000.00**

Appendix F

Flare Cost Breakdown/Quote

FLARE INDUSTRIES
INNOVATIVE COMBUSTION SOLUTIONS

BUDGETARY PROPOSAL

DEBBIE WALD, LLC
LITTLETON, COLORADO

PROJECT

FULLY ENCLOSED, NATURAL DRAFT FLARE SYSTEM

WESTERN SLOPE OF COLORADO

Prepared for:	Debbie Wald
Phone No.:	(720) 253-3993
Email:	Dwald1@msn.com
Sales Contact:	Jon A. Sachs Regional Sales Manager – USA & Canada T +1 (512) 836-9473 F +1 (512) 836-3025 jsachs@flareindustries.com
Local Contact:	Bruce Merritt - Thermex T +1 (303) 690-6866 F +1 (303) 690-0749 thermex@worldnet.att.net
Date:	June 15th, 2009
Quote No.:	090388

1.0 COMMERCIAL SUMMARY

1.1 SCOPE OF WORK

ITEM	QTY	DESCRIPTION	PRICE
1	1	**FEF-192-ND Natural Draft Enclosed Flare:**	

- 40 foot height x 16 foot diameter Enclosed Combustion Chamber
    - (2) Lifting Lugs
    - (1) Thermocouple Port, Thermowell & Type K Thermocouple for Over fire Protection
    - (2) 4 inch Sample Ports at 90° Spacing
    - Sight Glass Ports to View Burner & Pilot
    - 3 inch Thermal Insulation (up to 8 foot elevation)
    - 2 inch Thermal Insulation (above 8 foot elevation)
    - Anchors for Thermal Insulation – 310 SS
    - Rain Guard to Protect Refractory – 304 SS
- Modular Panel Construction for Easy Installation/Erection
- FII Standard Paint System
- Material of Construction – Carbon Steel

ITEM	QTY	DESCRIPTION	PRICE
2	1 Lot	**Waste gas burner assembly:**	

- Vertical Fired Burner Assembly
- Burner Materials – 316 Stainless Steel
- Burner Manifold Material – Carbon Steel

ITEM	QTY	DESCRIPTION	PRICE
3	4	**Luminex Pilot Assembly:**	

- Electronic Spark Ignition
- Ignition Monitoring via UV Scanner
- Material of Construction:
- Pilot Nozzle – 310 Stainless Steel
- Pilot Body – 316 Stainless Steel

ITEM	QTY	DESCRIPTION	PRICE
4	1 Lot	**Louvered Combustion Air Control System :**	

- Fully Adjustable Air Dampers
- Designed to Draft 100% of Air Required at All Times
- (4) Louvers Located at 90° Spacing
- (1) Louver to be Hinged for Manway Access
- Standard Enclosed Flare Paint System
    - Carboline CarboZinc 11 Primer
    - Top 3 inch - Sherwin Williams Flame Control #500 - Black
    - Remainder - Carboline 133 HB Gray Top Coat

ITEM	QTY	DESCRIPTION	PRICE
5	1	**FEF-192 Control System:**	

- NEMA 4X Weatherproof Controls Enclosure
- Thermocouple Indicator and Over fire Alarm
- Pilot Monitoring and Pilot Failure Alarm & Shutdown
- Automatic Ignition & Re-Ignition of Pilot
- Flame Safeguard
- Pilot Status Indication

- Form C Dry Contacts for Customer Alarms
- Pilot Gas Valve Train:
  - Aluminum Body Pressure Regulator
  - Ball Valve and Strainer
  - Pressure Gauge

6	3	**Operation & Maintenance Manuals** • Additional Manuals - $300.00 minimum each	
		Total for Items 1 – 6:	**$ 447,495.00**
		OPTIONS	
7	1	**Ladders & Platforms package:** • (2) 90° Galvanized Working Platform • Provides access to (2) sample ports • Galvanized Caged Ladder Assembly	**$ 47,360.00**
8	1	**8-inch Inlet shutoff valve:** • Wafer Style Butterfly Valve w/ pneumatic Actuator • Carbon Steel Body / Stainless Steel Internals	**$ 6,870.00**
9	1	**8-inch Flame Arrestor:** • Carbon Steel Body / Stainless Steel Internals	**$ 4,195.00**

1.2 VALIDITY

The prices in this quotation are budgetary.

1.3 DELIVERY

Approval Drawings:	8 Weeks after Receiving of Order
Client Review:	As Required, But not to exceed 6 Weeks *
Fabricating the Project:	18 Weeks after Receiving the Approved Drawings
Time Required for Project:	26 Weeks ARO + Client Review

The quoted delivery is based upon our current production schedule / shop load. An updated delivery schedule will be available at time of order.

* If Flare Industries does not receive approval for construction within 6 weeks of initial approval drawing submittal, the production schedule will be subject to change based upon shop load.

1.4 SHIPPING TERMS

- [x] Ex-works, Austin, TX
- [ ] Ex-works, point of manufacture
- [ ] FCA. Houston, TX
- [ ] CIF.

1.5 PACKING AND SHIPPING PREPARATION

Export packing and crating when quoted as an option only includes technology items and does not include stacks, vessels, skids, ladders and platforms, or utility piping.

- [x] Inland freight packing
- [ ] Export packing
- [ ] Storage & Preservation crating - 90 days maximum storage

1.6 TERMS OF PAYMENT

Progress payments as per the following*:

50% Upon receipt of order and prior to submittal of approval drawings, net 30
40% Upon procurement of major materials and prior to shipment, net 30
10% Upon notification of readiness for shipment, net 30

*Payment terms are only valid as long as client is approved for credit by FII's financial institution. Three credit references and financial statements may be requested for this purpose.

1.7 INSTALLATION - COMMISSIONING

To aid in start-up and commissioning Flare Industries will provide a qualified technician as follows:

• Daily rate (8 hr/day):	$960 (Portal to Portal)
• Travel Time:	As per Daily Rate
• Subsistence:	$75 / day
• Accommodation:	$175 / night
• Expenses (airfare, car rental):	Cost + 10%

Note: Installations with less than 7-day advance notices are subject to premium rates.
Note: Air flights over 8 hours in duration will be charged as business class.

2.0 TECHNICAL SUMMARY

2.1 DESIGN CONDITIONS

FEF-192

Maximum Inlet Flow Rate:	6.5 MMSCFD
Smokeless Flow Rate:	6.5 MMSCFD
Molecular Weight:	18.71
Flare Gas BTU Value:	791 BTU / scf
Available Inlet Pressure:	20 psig
Inlet Temperature:	70°F
Operating Temperature:	Up to 1600°F
Destruction Efficiency	95% to 98%

2.2 SITE CONDITIONS

Wind Speed for Radiation Calculations:	20 m.p.h.
Wind Speed for Structural Calculations:	90 m.p.h.
Seismic Zone:	0
Elevation:	~ 5400 feet above sea level

2.3 CLARIFICATIONS

2.4 UTILITIES

Pilot Gas:	65 SCFH of natural gas @ 15 - 250 psig (Per Pilot)
Electrical:	1ϕ / 60Hz / 120 VAC controls

2.5 DOCUMENTATION

Flare Industries will provide the following documentation along with the equipment on this project:

- ☒ Piping and instrumentation diagram (P&ID)
- ☒ Mechanical general arrangement
- ☐ Ladder Logic Diagrams
- ☐ Control Enclosures Drawings
- ☒ Operating & maintenance manuals (upon shipment)
- ☐ Manufacturing Record Books (MRB)

2.6 QUALITY / NON-DESTRUCTIVE TESTING

- ☒ Visual inspection
- ☒ Dimensional check
- ☒ Factory acceptance test (ignition system only)
- ☒ Dry film thickness
- ☐ Radiography extent:
- ☐ Dye penetrant examination extent:
- ☐ Ultrasonic testing extent:
- ☐ Magnetic particle examination extent:
- ☐ Hydro-testing extent:
- ☐ Pneumatic testing extent:
- ☐ Hardness/Impact Testing
- ☐ PMI

2.7 EXCLUSION LIST

Flare Industries' proposal is in accordance with project specifications, except for the following items, which are currently excluded from our scope of supply both legally and contractually, irrespective of any language to the contrary that might form a part of the specifications and / or eventual purchase order. These items can be included in our scope of work upon client request, subject to price and delivery impact.

TECHNICAL EXCLUSIONS

1. Civil and foundation design for any equipment including dead men, anchor bolts or nuts, design of anchor bolt length or projection as this is part of civil engineering foundation design.
2. This design is exclusive of all external loadings due to upstream piping. Wind, seismic and temperature loadings have been considered. Allowable nozzle loads other than those published by ANSI are not considered.
3. Air Craft Warning Lights unless mentioned in scope of work section of proposal.
4. Bolt Kits at battery limit flanged connections
5. Supply to Customer of shop details, fabrication drawings or proprietary calculations
6. Installation of equipment including supply of cranes and/or personnel. General installation instructions and assembly drawings will be provided, however, detailed erection instructions and drawings are excluded. These instructions are meant to provide guidance and general steps to complete the installation. These procedures are not intended to be a substitute for experienced installation personnel. Field assembly and erection of the flare is outside the scope of work to be provided by Flare Industries and is the sole responsibility of others. It is understood that the field contractor retained for this purpose is familiar with the assembly and erection of tall towers.
7. Structural design for stacks greater than one hundred feet in height does not include provision or facility for single piece lift or single point lift. Stack riser erection should take place in a vertical, section-by-section fashion.
8. No interconnecting piping, wire, or conduit is included between proposed equipment, unless otherwise indicated in the scope of work section of proposal.
9. The ignition system / control panel and related valve trains are a Flare Industries' standard package. As such, they are designed and / or manufactured according to our standards and procedures, using our standard components. All valve train components have the following characteristics: ½ to ¾ inch diameter, threaded fittings, carbon steel construction. No other materials, diameters, flange ratings, piping specifications, or additional materials or instrumentation are included, nor do any client supplied specifications apply, unless specifically agreed to in writing by Flare Industries.
10. Refractory of any kind in flare tips, unless specifically indicated. Using refractory in flare tips is an antiquated practice that actually reduces working life by creating heat sinks, which can cause premature failure of such tips. Over time, refractory can also become brittle and fall down into molecular seals, knockout drums, and liquid seals and subsequently cause system failures.

11. All calculations, engineering, and sizing provided in our proposal are preliminary and may change during detailed engineering. We will not be held responsible for changes, which occur during project phase engineering.
12. Dispersion calculations, nozzle load calculations, finite element analysis or other stress analysis, apart from structural calculations of the stack.
13. Structural calculations will be submitted for information only, not being subject to the approval process.
14. Corrosion allowance for carbon steel is 1/16 inch on wetted parts and 0 for non-wetted parts. No other corrosion allowance is applicable to our design or scope of work.
15. Standard deflection criterion for guyed stacks is L/100 and for self supported stacks and derricks is L/133. No other deflection criteria are applicable.
16. If sour service is applicable, the chemical composition of the materials supplied for wetted parts will comply with NACE MR-01-75. Materials which exceed the requirements of NACE MR-01-75 are not considered.
17. Passivation or pickling of stainless steel materials or procedure, post weld heat treatment, procedures, or associated charts.
18. Any testing or procedures not marked as included in the quality / testing section of proposal.
19. Flare Industries' standard weld procedures apply to our equipment, unless otherwise stated in our proposal. Any request to alter or modify our current weld procedures based upon clients' internal specifications is currently excluded from our scope of supply. If new procedures are requested by the client, price and delivery impact will apply.
20. Hydro-testing or procedures of any piece of equipment other than stamped ASME pressure vessels, unless specifically indicated in the proposal.
21. Flare stacks are open to atmosphere; pressure vessel design codes and related design pressures do not apply.
22. Painting or coating for stainless steel, internal surfaces of equipment or galvanized equipment.
23. External insulation, insulation clips or heat tracing of any kind. Refractory or insulation is included for enclosed combustion devices.
24. Armored cable or cable tray of any kind. We are supplying our standard wire and conduit within our battery limits.

COMMERCIAL EXCLUSIONS

1. Whereas regards statements in client specifications or purchase orders concerning specification order of precedence, please be advised that Flare Industries' proposal, including its integral exclusion list, precedes and precludes all other documents or agreements whether written or verbal.
2. Freight costs and logistics will be offered to our clients as an optional price or as part of the base price, but not at cost as the phrase "prepay and add" is sometimes interpreted.
3. Flare Industries strictly prohibits the use or sale of our equipment in countries sanctioned by the United States Government such as: Iran, Syria, Sudan, North Korea, and Cuba.
4. Third Party Inspection
5. All documentation will be supplied in Acrobat pdf format, not Word, Excel, AutoCAD, or any other format.
6. Please note that documentation and drawing delivery dates are as stated in our proposal, however, if a VDS applies to the project, all delivery dates must be agreed to in writing on a document by document basis.
7. Documentation Legalization Costs.
8. Our operating and maintenance manuals and quality dossiers will be provided in the English language. Translation of the O&M manuals is available at an additional cost; however, only text generated by FII will be translated. Drawings, cut sheets, data sheets and/or standard documents will be provided in English.
9. Presence at meetings (including, but not limited to, kick-off meetings, HAZOP meetings, drawing review and inspection / certification meetings) is included, unless explicitly mentioned in section 1.3.
10. Spare parts when quoted do not include cross sectional drawings, export packing or freight.
11. There are no bank guarantees, performance bonds, or warranty bonds included in our scope of supply or price. Cost for these requirements will be added on to our base price quoted as options. All bond and/or bank guarantee formats, if applicable, must be agreed to in writing by Flare Industries.
12. Storage of equipment after notification of readiness for shipment.

3.0 WARRANTY

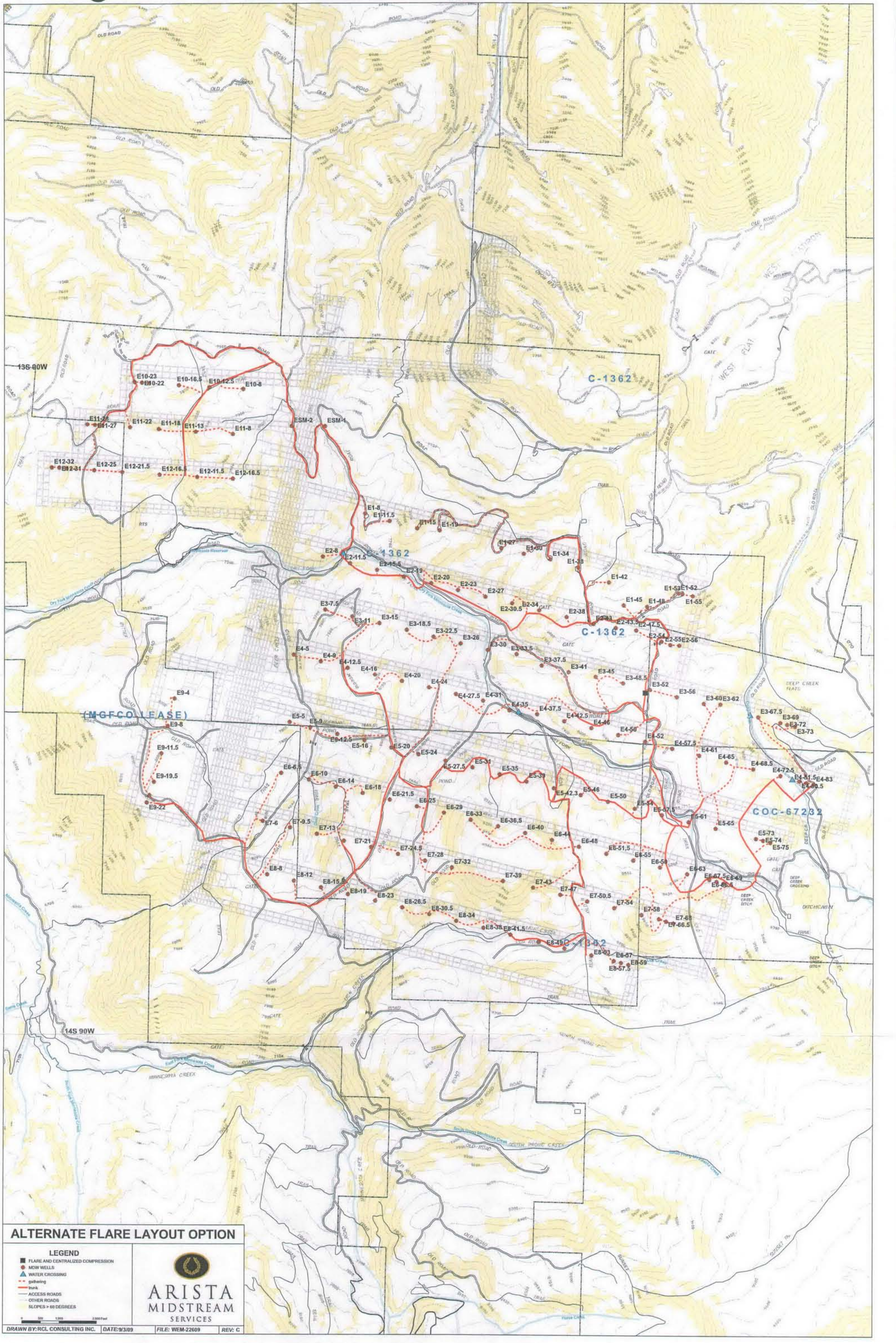
If within 18 months after the date of notice of availability for shipment, or one year after start up, whichever occurs first, any Goods furnished by Seller prove to be defective in material or workmanship, and Seller is so notified in writing, upon examination by Seller, Seller will, at Seller's discretion, either repair the Goods or supply identical or substantially similar replacement Goods, F.O.B. manufacturing facility. Any repaired or replacement Goods will be warranted against defects in material or workmanship for the unexpired portion of the warranty applicable to the particular Goods. Goods not manufactured by Seller are subject only to warranties of Seller's vendors and Seller hereby assigns to Buyer all rights in such vendors warranties, provided however. Seller shall furnish to the Buyer reasonable assistance in enforcing such rights. Seller will not be responsible for costs of making access for, or of export/import, shipment, removal or installation of any items needed to repair or replace any defective Goods. Inexpensive items requiring repairs or replacement and routine maintenance-related or consumable items shall be outside the scope of these limited warranties. With regard to warranty related remedial work, the Seller will not be responsible for materials or workmanship of others or shipment, labor and other related expenses for any work performed by others in the repair or replacement of defective Goods, without Seller's prior written consent. Seller's performance guarantees, if any, shall be deemed to be met by a satisfactory demonstration of the performance guarantees during a performance test, which shall be the responsibility of the Buyer, pursuant to mutually agreed upon test procedures. If the performance test is not completed within 45 days after notice of availability for shipment, the performance test shall be deemed to be satisfactorily performed for any and all purposes.

4.0 TERMS AND CONDITIONS

Unless otherwise agreed to in writing, this proposal is subject to Flare Industries' terms and conditions, (Annex I) of which a copy is available by request.

Appendix G

Alternate Flare Option


ALTERNATE FLARE LAYOUT OPTION
LEGEND
FLARE AND CENTRALIZED COMPRESSION
MDW WELLS
WATER CROSSING
gathering
trunk
ACCESS ROADS
OTHER ROADS
SLOPES > 60 DEGREES
ARISTA
MIDSTREAM
SERVICES
DRAWN BY: RCL CONSULTING INC.
DATE: 9/3/09
FILE: WEM-22609
REV: C
13S 90W
14S 90W
C-1362
COC-67232
(MGFCO LEASE)
ESM-1
ESM-2
DEEP CREEK FLATS
WEST FLAT

West Elk Gas Gathering System
Alternate Flare Capital

MDW wellheads	$	2,995,500
E System Gathering	$	4,926,655
Flare Installation	$	450,000
Control System	$	180,000
Engineering (10%)	$	855,216
TOTAL PROJECT COST	**$**	**9,407,371**

West Elk Mine
MDW Wellheads

Description	Quantity	Units	Unit Cost	Total Cost	CATEGORY TOTAL
Material					
Exhauster	Already Owned, no additional capital				
Relief Valve	1	lot	$ 15,000	$ 15,000	
Separator	1	lot	$ 25,000	$ 25,000	
Water Tank w/heater	1	lot	$ 20,000	$ 20,000	
Screw Compressor	1	lot	$ 380,000	$ 380,000	
Fuel Conditioning System	1	lot	$ 15,000	$ 15,000	
Meter Skid w/efm	1	lot	$ 30,000	$ 30,000	
Methanol injection	1	lot	$ 5,000	$ 5,000	
BTU Monitoring	1	lot	$ 10,000	$ 10,000	
Sat. Communications	1	lot	$ 10,000	$ 10,000	
Misc valves, fittings, pipe	1	lot	$ 7,500	$ 7,500	
Total Material					**$ 517,500**
Installation					
Exhauster	Already estimated in Arch budgets				
Screw Compressor	1	lot	$ 75,000	$ 75,000	
Well Head Equipment	1	lot	$ 50,000	$ 50,000	
Total Installation					**$ 125,000**
Project Management					
Engineering included in Roll Up					
Inspection	10	days	$ 1,000	$ 10,000	
Contingency	15	%	$ 642,500	$ 96,375	
Total Project Management					**$ 106,375**
TOTAL COST PER WELL					**$ 748,875**
Number of wells	**4**				
TOTAL PROJECT COST					**$ 2,995,500**

West Elk Mine
"E" Seam Gathering

Description	Quantity	Units	Unit Cost	Total Cost	CATEGORY TOTAL
Material					
10" SDR 11 Poly	92795	ft	$ 3.89	$ 360,972	
6" SDR 11 Poly	114707	ft	$ 1.48	$ 169,767	
Valves	1	lot	$ 100,000	$ 100,000	
12" pig traps	3	each	$ 60,000	$ 180,000	
Total Material					$ 810,739
Installation					
10" SDR 11 (per Petty quote)	92795		$ 23	$ 2,134,280	
6" SDR 11 (per Petty quote)	114707	ft	$ 10	$ 1,147,073	
Pig Traps	3	each	$ 35,000	$ 105,000	
Total Installation					$ 3,386,353
Project Management					
Engineering included in Roll Up					
Inspection	100	days	$ 1,000	$ 100,000	
Contingency	15	%	$ 4,197,091	$ 629,564	
Total Project Management					$ 729,564
TOTAL PROJECT COST					**$ 4,926,655**

West Elk Mine
Control System

Description	Quantity	Units	Unit Cost	Total Cost	CATEGORY TOTAL
Material					
Gas Quality Equip.	1	lot	$ 50,000	$ 50,000	
Alarm Callout System	1	lot	$ 15,000	$ 15,000	
SCADA System	1	lot	$ 50,000	$ 50,000	
Total Material					**$ 115,000**
Installation					
Gas Quality Equip.	1	lot	$ 15,000	$ 15,000	
SCADA/Alarm	1	lot	$ 50,000	$ 50,000	
Total Installation					**$ 65,000**
TOTAL PROJECT COST					**$ 180,000**

West Elk Mine O&M
Alternate Flare Option

				COST	
Labor	# emp.	base	w/30% load		
Supervisor	1	100000	130000		
I&E Tech	1	80000	104000		
Mechanic/Operator	6	70000	546000		
				$	780,000.00
Trucks	6	(1500/month)		$	108,000.00
Methanol	50000	gallons		$	150,000.00
Compression	# units	hp	$100/hp		
working screws	4	400	160000		
sealed screws		400	0		
				$	160,000.00
Winter Operations					
Move Screws	0	25000	0		
Move 10" temp poly	0	20	0		
				$	-
Measurement/Scada	# meters	10000/yr			
working screws	4	40000			
sealed screws	0	0			
System	2	20000			
				$	60,000.00
Office/Misc	12	months @ 20k each		$	240,000.00
TOTAL				**$**	**1,498,000.00**

Appendix H

Cost Estimate for Gas Sales

West Elk Gas Gathering System
E SEAM GAS SALES

Basic Gathering System	$	12,107,320	See Appendix D for breakout
Flare	$	450,000	
Gas Plant	$	12,347,500	
Bull Mountain Sales Lateral	$	10,488,584	

TOTAL PROJECT COST $ 35,393,404

West Elk Mine
Gas Plant

Inlet Compression 30 to 600 psig (7 mmcf/day)	**$**	**1,750,000**
Oxygen Removal (X-O2)	**$**	**1,750,000**
Glycol Dehydration	**$**	**125,000**
Nitrogen/CO2 Removal (PSA)	**$**	**3,000,000**
Instalation	**$**	**3,200,000**
Outlet Compression	**$**	**1,000,000**
Electrical	**$**	**400,000**
Engineering (10%)	**$**	**1,122,500**
Total	**$**	**12,347,500**

West Elk Mine
Bull Mountain Sales Lateral

Description	Quantity	Units	Unit Cost		Total Cost		CATEGORY TOTAL	
Material								
10" steel pipe (Gr B std wt)	78347	ft	$	36.75	$	2,879,252		
Valves	1	lot	$	100,000	$	100,000		
12" pig traps	2	each	$	60,000	$	120,000		
Total Material							$	**3,099,252**
Installation								
Lay Price (per Petty Quote)	78347	ft	$	45.00	$	3,525,615		
Bore Price	4000	ft	$	400	$	1,600,000		
Pig Traps	2	each	$	35,000	$	70,000		
Total Installation							$	**5,195,615**
Project Management								
Engineering	10	%	$	8,294,867	$	829,487		
Inspection	120	days	$	1,000	$	120,000		
Contingency	15	%	$	8,294,867	$	1,244,230		
Total Project Management							$	**2,193,717**
TOTAL PROJECT COST							$	**10,488,584**

Appendix I

O&M Cost for Gas Sales

West Elk Mine O&M
Gas Sales

				COST	
Labor	# emp.	base	w/30% load		
Supervisor	1	100000	130000		
I&E Tech	1	80000	104000		
Mechanic/Operator	6	70000	546000		
				$	780,000.00
Trucks	6	(1500/month)		$	108,000.00
Methanol	50000	gallons		$	150,000.00
Compression	# units	hp	$100/hp		
working screws	6	400	240000		
sealed screws	2	400	80000		
				$	320,000.00
Winter Operations					
Move Screws	12	25000	300000		
Move 10" temp Poly	6000	20	120000		
				$	420,000.00
Measurement/Scada	# meters	10000/yr			
working screws	6	60000			
sealed screws	2	20000			
System	2	20000			
				$	100,000.00
Gas Plant/Sales Line			annual cost		
Plant			700000		
Sales Compression			150000		
Sales Pipeline			100000		
				$	950,000.00
Office/Misc	12	months @ 20k each		$	240,000.00
TOTAL				**$**	**3,068,000.00**

EXHIBIT G

BURNS & MCDONNELL REPORT

West Elk Coal Mine Methane Due Diligence Evaluation

Prepared For

Mountain Coal Company, LLC

West Elk Mine MOUNTAIN COAL COMPANY L.L.C.

September 2009

Project 52725

Burns & McDonnell
SINCE 1898

WEST ELK COAL MINE METHANE DUE DILIGENCE EVALUATION

prepared for

MOUNTAIN COAL COMPANY, LLC

prepared by

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Kansas City, Missouri

Project 52725

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TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

* * * * *

EXECUTIVE SUMMARY

EXECUTIVE SUMMARY

This report section presents an executive summary of the West Elk CMM Due Diligence Evaluation (Study). The Study was completed by Burns & McDonnell Engineering Company (B&McD) for Mountain Coal Company, LLC (Mountain Coal). The objectives, methodology, and results of the Study are described in the following sections.

ES.1 STUDY BACKGROUND

B&McD was retained to review the results of previous studies regarding coal mine methane (CMM) utilization at the West Elk Mine and also evaluate other beneficial uses, such as power generation, in order to compare alternatives for the beneficial use of methane from the mine. The E Seam Longwall District is the area currently being mined by Mountain Coal and is the focus of the analysis provided by the Study.

ES.2 GAS GATHERING SYSTEM AND FLARE

CMM liberated in the mine districts is collected by multiple wellheads located throughout previously mined areas and areas that will be mined in the future. Arista Midstream Services (Arista) was retained to complete a conceptual design for a well and collection system. The gathering system was designed for an average of 4 million cubic feet per day (MMCFD) total gas, of which 55%, or 2.2 MMCFD, is methane. The design also included a flare for combustion and destruction of methane.

Arista provided a cost estimate for the well and collection system for use in the Study. The system collects and transports CMM to a location where it can be destroyed by a flare, processed to create saleable natural gas, or used for power generation. The cost estimate included eight wellhead setups, 35.6 miles of 6-inch SDR11 poly panel laterals, 9.9 miles of 10-inch SDR11 poly trunkline, and various control equipment. Arista's estimate for design and construction of this system was $12,107,000. Installation of a flare to destroy methane would add another $450,000 to the well and collection system cost. An alternate flaring location could potentially be utilized if power generation and gas processing are not performed or retained as future options. With this scenario, if flaring is performed at a location closer to the collection system, the capital and operating costs of the system can be reduced. The capital cost of this alternate flaring location is $9,407,000, including the cost of the flare.

In addition to developing estimates for the well and collection system, Arista also provided an estimate for the installation of a gas processing facility that produces natural gas from CMM. The natural gas could then be sold and transported via pipeline to the Bull Mountain pipeline system. The gas processing facility would require the same CMM well and collection system to gather and deliver the mine gas. The Arista estimate for the processing facility was $22,836,000. The processing facility cost is in addition to the well and collection system cost.

ES.3 POWER GENERATION OPTIONS

B&McD investigated the use of combustion turbines (CT) and reciprocating engines to generate electrical power with the CMM. Both options are capable of burning CMM with a methane content of 55%. B&McD reviewed a potential location for the power generating site adjacent to the existing Sylvester Gulch substation and determined that adequate space is available for construction of the facility.

The Kawasaki GPB15 was the model selected as a representative choice for CT technology. The CT is delivered on a skid with complete indoor enclosure and major components such as the lube oil system and control system included and preassembled. For reciprocating engine technology, the GE Jenbacher JMS 620 GS-N.L was selected. The engine is delivered on a skid with major components such as the pre-chamber compressor, the lube oil system and programmable logic control system included and preassembled. Capital cost estimates for each option are provided in Table ES-1. Based on the amount of CMM available, four CTs and four reciprocating engines are included in the cost estimates. The cost of the well and collection system would be in addition to the power plant costs presented below.

Table ES-1: Generating Options Capital Cost Summary

		Kawasaki GPB15 (4,600 kW)	GE Jenbacher JMS 620 (10,550 kW)
Turbine/Engine ($)		6,263,000	6,662,000
Mechanical ($)		38,000	230,000
Electrical ($)		1,482,000	1,737,000
Structural ($)		457,000	681,000
Civil ($)		403,000	403,000
Emission Controls ($)		2,493,000	3,044,000
Subtotal ($)		**$11,136,000**	**$12,757,000**
Engineering and Management Cost	10%	1,114,000	1,276,000
Overhead	18%	2,205,000	2,526,000
Owner's Cost inc. Contingency	20%	2,891,000	3,312,000
TOTAL Capital Cost (2009$)		**$17,300,000**	**$19,900,000**
Cost per kW ($/kW)		**$3,760**	**$1,890**

ES.4 PROJECT ECONOMICS

In order to compare the economics of the beneficial uses of CMM in power generation, flaring to destroy methane, and processing to yield natural gas, an economic pro forma model was developed. The model utilized various financial inputs and project-related costs and revenues to estimate an internal rate of return (IRR) and net present value (NPV) for each of the beneficial use alternatives.

The model utilized key inputs to estimate project expenses and revenues over a 10-year period from 2012 to 2021, resulting in a cash flow projection for each beneficial use option. Key expenses for the project included gas royalty payments (where applicable) to the Bureau of Land Management, principal and interest expenses for the debt required to finance the project, O&M expenses including staffing costs, income taxes, and various expenses such as insurance and property taxes. Revenue streams for the project were produced from the sale of energy for options that include generation, the sale of natural gas for the gas processing option, and the potential sale of CO_2 offsets that may be generated by the destruction or conversion of methane that takes place in all options.

Table ES-2 provides a summary of each option, including operational data, revenue requirements, expected revenues, and IRR/NPV results.

Table ES-2: Economic Model Summary Results

	Option 1 Flaring System		**Option 2 Power Generation - CTs**		**Option 3 Power Generation - Recips.**		**Option 4 Gas Processing**	
Net Project Output (kW)	NA		4,400		10,560		NA	
Net Heat Rate, LHV (Btu/kWh)	NA		14,900		8,320		NA	
Total Capital Cost (2009$)	Well/Collection - $12,107,000 Flaring System - $450,000		Well/Coll./Flare - $12,557,000 CTs - $17,300,000		Well/Coll./Flare - $12,557,000 Recip. Engines - $19,900,000		Well/Coll./Flare - $12,557,000 Gas Processing - $22,836,000	
Estimated Annual Generation (MWh)	NA		32,762		78,630		NA	
Annual CO_2 Equivalent Destroyed (tonnes)	229,990		229,990		229,990		229,990	
Year	Expenses ($000)	Revenue ($000)	Expenses ($000)	Revenue ($000)	Expenses ($000)	Revenue ($000)	Expenses ($000)	Revenue ($000)
2012	4,622	NA	8,925	2,492	9,917	5,981	10,292	3,764
2013	4,640	NA	8,893	2,567	9,888	6,161	10,255	3,831
2014	4,655	NA	8,852	2,644	9,849	6,346	10,207	3,897
2015	4,667	NA	8,804	2,723	9,802	6,536	10,150	3,988
2016	4,676	NA	8,736	2,805	9,734	6,732	10,071	4,012
2017	4,680	NA	8,670	2,889	9,670	6,934	9,994	4,170
2018	4,679	NA	8,581	2,976	9,579	7,142	9,891	4,248
2019	4,673	NA	8,482	3,065	9,480	7,356	9,776	4,376
2020	4,662	NA	8,365	3,157	9,362	7,577	9,641	4,507
2021	4,643	NA	8,231	3,252	9,223	7,804	9,484	4,642
IRR (%) Less than Zero = NA	NA		NA		NA		NA	
NPV ($000), 2009$	($26,170)		($35,010)		($19,892)		($35,852)	

Based on the model results, none of the projects are presently financially viable given the baseline revenue inputs. Revenues from the sale of electricity and natural gas are significantly less than the total expenses that result from construction and operation of each project. Of the options analyzed, reciprocating engines are the most economical. However, even if energy from the units can be sold for \$71/MWh, the NPV of the reciprocating engines is negative \$19.9 million.

In order to determine the effect of modifying key project inputs, the IRR was calculated over a range of values for energy sales and gas sales values. The conclusions drawn by the sensitivity analyses are provided in Table ES-3.

Table ES-3: Sensitivity Analysis

Key Input	Baseline Value	Hurdle Value[1]
Energy Sales Value (2009\$/MWh)	\$71	\$114 - Recip. Engine \$246 - CT
Gas Sales Value (2012\$/MMBtu, % Increase Over Baseline)	\$6.22	\$18.66 - Gas Processing Option 200% Increase Over Baseline (3x Baseline Value)

[1]Input reaches 'Hurdle Value' when IRR equals 10.99%

The hurdle value presented for both key inputs, energy sales and gas sales values, is the point at which the project will achieve a 10.99% IRR. For example, the gas processing option will not result in a 10.99% IRR until the value of gas sold from the project is \$18.66/MMBtu. Compared to a baseline input of \$6.22/MMBtu in the economic model, a gas sales hurdle value of \$18.66/MMBtu is significantly higher. Similarly, energy sales values of approximately \$114/MWh and \$246/MWh are necessary for the reciprocating engine and CT options, respectively, to achieve a 10.99% IRR.

ES.5 CARBON OFFSETS AS A REVENUE STREAM

Each of the methane management options described in this report can potentially generate CO_2 offsets, as methane is combusted. Carbon markets are currently in a state of significant flux. Presently, carbon offsets are primarily bought and sold in voluntary marketplaces such as the Chicago Climate Exchange (CCX). However, draft legislation in Congress would create a federally mandated cap-and-trade system, which in theory may create a robust market in CO_2 offsets. Uncertainty regarding the contours of legislation has depressed CCX prices as potential traders and regulated parties delay trades.

In order to gauge the impact to IRR due to revenue from potential CO_2 offset sales, the model was run over a range of offset values, and the IRR was calculated for each case. Table ES-4 presents the results of the analysis.

Table ES-4: Carbon Offset Sales Analysis

Option	CO_2 Hurdle Value[1]
Flaring System	\$19.25/tonne
Alternate Flaring System	\$14.25/tonne
CTs	\$26.50/tonne
Recip. Engines	\$15.50/tonne
Gas Processing	\$27.00/tonne

[1] CO_2 reaches 'Hurdle Value' when IRR equals 10.99%

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INTRODUCTION

1.0 INTRODUCTION

Arch Coal, Inc. (Arch), on behalf of Mountain Coal Company LLC (Mountain Coal), retained Burns & McDonnell (B&McD) to perform an evaluation of possible beneficial uses of coal mine methane (CMM) that is liberated from coal and surrounding materials during and subsequent to mining activities. The evaluation includes multiple beneficial uses of CMM, including:

- Power generation using either reciprocating engine or combustion turbine (CT) technology
- Flaring of CMM to destroy methane
- Processing the CMM to yield saleable natural gas

Each of the above options results in the destruction or conversion of methane into another form thereby reducing greenhouse gas effects from the emissions.

1.1 STUDY OBJECTIVES AND METHODOLOGY

For many years Mountain Coal has evaluated beneficial uses of CMM. Recent clarification in ownership rights has led Mountain Coal to revisit possible beneficial uses. Mountain Coal, or its consultants, has recently completed numerous studies regarding expected gas yields, collection systems, cleanup, and beneficial use at West Elk Mine (West Elk or Mine). Mountain Coal retained B&McD to review the results of these studies and also evaluate other beneficial uses, such as power generation, in order to compare alternatives for the beneficial use of methane from the Mine. The E Seam Longwall District is the area currently being mined by Mountain Coal and is the focus of the analysis provided by the Study.

1.2 OTHER SOURCES OF INFORMATION

In preparation of the Study, B&McD utilized information prepared by Arista Midstream Services (Arista) relating to CMM rates and volumes, conceptual CMM gathering system, flaring of excess CMM, and processing of CMM to produce pipeline quality natural gas. The following information was developed by Arista and utilized in the Study:

- 10-year E Seam CMM yield rate
- CMM gathering system conceptual design (capital cost, operating costs, and performance)
- Flaring system to combust excess methane not utilized for power generation
- CMM processing to yield pipeline quality natural gas for sale into the interstate pipeline system

The information from Arista was used in conjunction with B&McD's cost estimates for various power generating scenarios to develop an economic model for comparison of the various options.

1.3 ORGANIZATION OF REPORT

This report is organized into several separate sections. These individual sections are listed below along with a brief description of their contents.

- Section 1.0 – Introduction: Provides a brief introduction that describes the objectives, methodology, other sources of information, and organization of the report.
- Section 2.0 – Gas Gathering System: Provides a discussion of the conceptual CMM well and collection system developed by Arista. The section includes capital and operating costs for the collection system, flare, and gas processing plant.
- Section 3.0 – Potential Generation Technologies: Describes the power generation options considered and provides capital cost and performance estimates.
- Section 4.0 – Air Emissions and Key Permits: Discusses anticipated emissions from the generating units and key permits that will be required for the project including construction and operating air permits, water supply permits, environmental permits, and local requirements.
- Section 5.0 – Project Economic Summary: Provides a summary of projected economics for each beneficial use option.

* * * * *

GAS GATHERING SYSTEM

2.0 GAS GATHERING SYSTEM

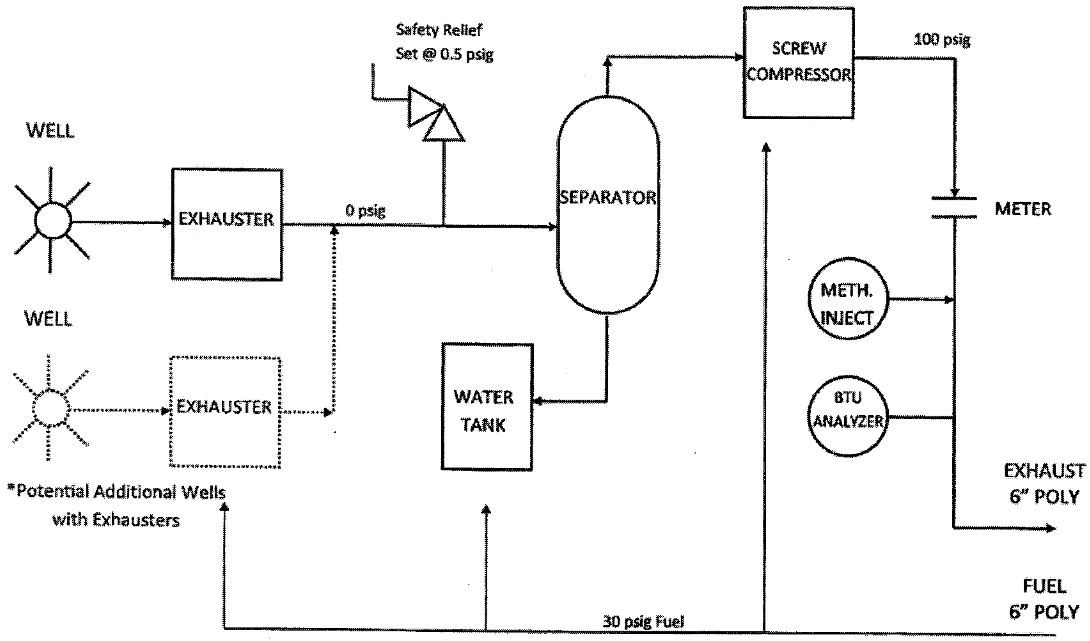
Arista prepared preliminary estimates of a CMM well and collection system required at the site to gather, process, and deliver CMM for power generation, flaring, or gas processing. Arista's efforts included development of capital and operating costs necessary for the well and collection systems. Furthermore, Arista developed standalone flaring and gas sales options, with no power generation. The flaring arrangement is also used in a bypass scenario for generation options to burn excess CMM not utilized for power generation. The gas sales option consists of a processing plant that conditions the CMM to create a saleable, pipeline quality natural gas product that can be sold and transported offsite.

2.1 CMM WELL AND COLLECTION SYSTEM

CMM liberated in the mine districts is collected by multiple wellheads located throughout previously mined areas and areas that will be mined in the future. The gathering system is designed for an average of 4 million cubic feet per day (MMCFD) total gas, of which 55%, or 2.2 MMCFD, is methane. The system design utilizes the existing well exhausters, installs new screw compression located at the wellheads, installs individual laterals along the mine panels, and installs a trunkline buried in the main road to bring gas to the area of the existing Sylvester Gulch substation. The substation is the probable location of generating equipment as further discussed in Section 3.0. The power generation, stand-alone flaring, and gas processing options include a highly engineered flare to destroy excess methane during operation or during times when the equipment is offline.

The following schematic provides a general flow diagram for an individual wellhead.

Figure 2-1: Wellhead Schematic



2.1.1 Well and Collection System Cost Estimate

A cost estimate to construct the well and collection system was developed by Arista. The costs presented below include eight wellhead setups, 35.6 miles of 6-inch SDR11 poly panel laterals, 9.9 miles of 10-inch SDR11 poly trunkline, and various control equipment. The collection system will deliver CMM to the flare, power generating equipment, or gas processing plant.

Table 2-1: CMM Well and Collection System Cost Estimate

System	Cost (2009$)
Methane Drainage Wellheads	$5,991,000
E System Gathering	$4,611,000
Control System	$405,000
Engineering (10%)	$1,101,000
TOTAL Capital Cost	$12,107,000

2.1.2 Well and Collection System Operating Costs

The operations and maintenance (O&M) of the well and collection system will be combined with the generating or gas processing equipment. The shared staff will operate and perform repair work on both systems. O&M will be performed by a staff of eight, including one supervisor, one instrumentation and electronics technician, and six operators that will also perform mechanic duties.

Table 2-2: Well and Collection System O&M Cost

				Cost (2009$)
Labor	Employees	Base		w/ 30% Load
Supervisor	1	100,000		$130,000
I&E Tech	1	80,000		$104,000
Mechanic/Operator	6	70,000		$546,000
		Subtotal		$780,000
Trucks	6 ($1,500/month)			$108,000
Methanol	50,000 gallons			$150,000
Compression	# units	hp		$100/hp
Working screws	6	400		$240,000
Sealed screws	2	400		$80,000
		Subtotal		$320,000
Winter Operations	# units	Cost per Unit		
Move Screws	12	25,000	$	300,000
Move 10" temp poly	6,000	20	$	120,000
			$	420,000
Measurement/Scada	# meters	$10,000/yr		
Working screws	6	$60,000		
Sealed screws	2	$20,000		
System	2	$20,000		
		Subtotal		$100,000
Office/Misc	12 months @ 20k each			$240,000
		TOTAL O&M Cost		**$2,118,000**

2.2 FLARING AND GAS PROCESSING FACILITIES

2.2.1 Gas Flaring

After collection of CMM, one option for destruction of the methane is combustion within a fully enclosed, natural draft flare system. A flare system would include an enclosed combustion chamber, waste gas burner assembly, pilot assembly, combustion air control system, and flare system control. Based on vendor quotations, Arista estimated the cost of a flare system to be $450,000. This cost is in addition to the well and collection system costs described in the previous section.

2.2.1.1 Alternate Flaring Location

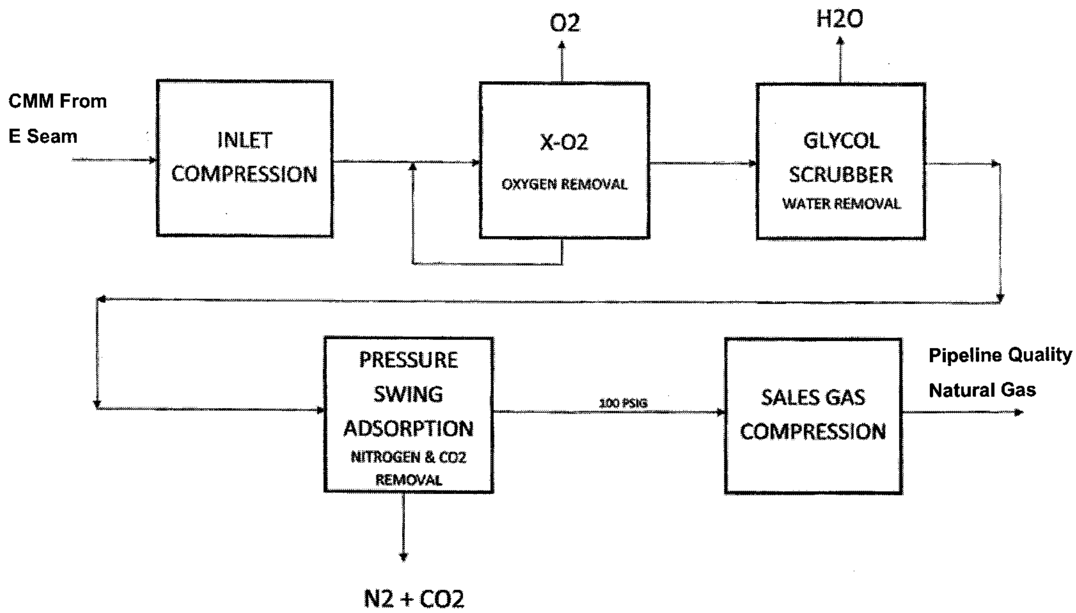
The design of the well and collection system is based on delivery of the gas to a location near the Sylvester Gulch substation for use in power generation and gas processing. However, if gas is not used for generation or processing, and flaring can be performed in a location closer to the collection system, the capital and operating costs of the system can be reduced. The capital cost of this alternate flaring location is $9,407,000, including the cost of the flare. The annual operating cost is $1,498,000.

2.2.2 Gas Processing Facilities

In addition to developing estimates for the collection and flaring systems, Arista also provided an estimate for the installation of a gas processing facility that will produce natural gas from CMM. The gas processing facility includes compressing the gas in preparation for processing, processing the gas to sales quality, compressing the sales gas, and transporting the sales gas to the nearest interstate pipeline, which is the Bull Mountain pipeline that is currently in construction. Producing pipeline quality natural gas for sale via the pipeline is an alterative to power generation. The options are considered exclusive of one another due to the amount of methane that will be available from the E Seam. Further discussion of power generating options is provided in Section 3.0.

The following schematic provides a general flow diagram for the gas processing system.

Figure 2-2: Gas Processing Schematic



2.2.2.1 Gas Processing Facility Cost Estimate

A cost estimate was developed for the gas processing option. The processing system was designed to treat the gathered raw gas so that pipeline quality gas is generated. In addition to methane (CH_4), the gas from the mine contains oxygen (O_2), carbon dioxide (CO_2), water (H_20), and nitrogen (N_2). The processing system was designed to remove these constituents and consists of the following major components:

- Inlet compression to increase the pressure of the mine gas
- Catalytic removal of O_2
- Glycol scrubber to remove water vapor
- Pressure Swing Adsorption (PSA) process to remove N_2 and CO_2
- Gas compressor to pressurize the natural gas for delivery to the interstate pipeline

The gas processing facility will require the same well and collection system to gather and deliver the mine gas as described in the previous section. Costs for the wells, collection system, and flare are in addition to the costs provided in the table below.

Table 2-3: Gas Processing Facility Cost Estimate

System	Cost (2009$)
Pipeline to Bull Mountain	$10,489,000
Gas Processing Plant	
Inlet Compression	$1,750,000
X-O2	$1,750,000
Glycol Dehydration	$125,000
Nitrogen/CO_2 Removal	$3,000,000
Installation	$3,200,000
Outlet Compression	$1,000,000
Electrical	$400,000
Engineering (10%)	$1,122,500
Subtotal	$12,347,500
TOTAL Capital Cost	**$22,840,000**

2.2.2.2 Gas Processing Facility Operating Costs

The O&M of the gas processing facility will be combined with the well and collection system. The shared staff will operate and perform repair work on both systems. The O&M costs presented below are for both systems.

Table 2-4: Gas Processing Facility O&M Cost

Labor	Employees	Base		Cost (2009$) w/ 30% Load
Supervisor	1	100,000		$130,000
I&E Tech	1	80,000		$104,000
Mechanic/Operator	6	70,000		$546,000
		Subtotal		$780,000
Trucks	6 ($1,500/month)			$108,000
Methanol	50,000 gallons			$150,000
Compression	# units	hp		$100/hp
Working screws	6	400		$240,000
Sealed screws	2	400		$80,000
		Subtotal		$320,000
Winter Operations	# units	Cost per Unit		
Move Screws	12	25,000	$	300,000
Move 10" temp poly	6,000	20	$	120,000
			$	420,000
Measurement/Scada	# meters	$10,000/yr		
Working screws	6	$60,000		
Sealed screws	2	$20,000		
System	2	$20,000		
		Subtotal		$100,000
Gas Plant/Sales Line	Annual Cost			
Plant		$700,000		
Sales Compression		$150,000		
Sales Pipeline		$100,000		
		Subtotal		$950,000
Office/Misc	12 months @ 20k each			$240,000
		TOTAL O&M Cost		**$3,068,000**

POTENTIAL GENERATION TECHNOLOGIES

3.0 POTENTIAL POWER GENERATION TECHNOLOGIES

CMM can be utilized as a source of combustion in various types of power generating equipment, including CTs and reciprocating engines. The CTs and engines, in turn, spin an electrical generator that produces electricity that can be connected to the power grid. Power generated at the West Elk Mine would be connected to the grid at the existing Sylvester Gulch substation. The substation currently serves as the interconnection point for the mine to the Delta-Montrose Electric Association (DMEA) transmission system.

The following sections discuss potential CT and reciprocating engine options for a CMM application. Expected capital and operating costs for each technology are provided.

3.1 GAS AVAILABILITY

In order to size the generation equipment to utilize the available CMM, a 10-year yield rate for the E-Seam was estimated by Arista. The amount of total gas available for power generation on a continuous basis was estimated to be 4 MMCFD with a 55% CH_4 content. Actual mine yields can vary significantly. During higher yield periods, the excess methane will be destroyed by the flare. The well and collection system, including the flare, was developed with an average gas capacity of 4 MMCFD. The collection system utilizes a small amount of methane to operate compression and exhausting equipment necessary to gather and transport the mine gas. The table below summarizes the gas availability estimate.

Table 3-1: E-Seam Methane Availability

	Total Gas Rate (MMCFD)	Methane Rate (MMCFD)
Average Gas Rate	4 MMCFD	2.2 MMCFD
Compression and Exhaust Usage	-	0.35 MMCFD
Methane Available for Generation	-	1.85 MMCFD

3.2 POWER GENERATION WITH COMBUSTION TURBINE(S)

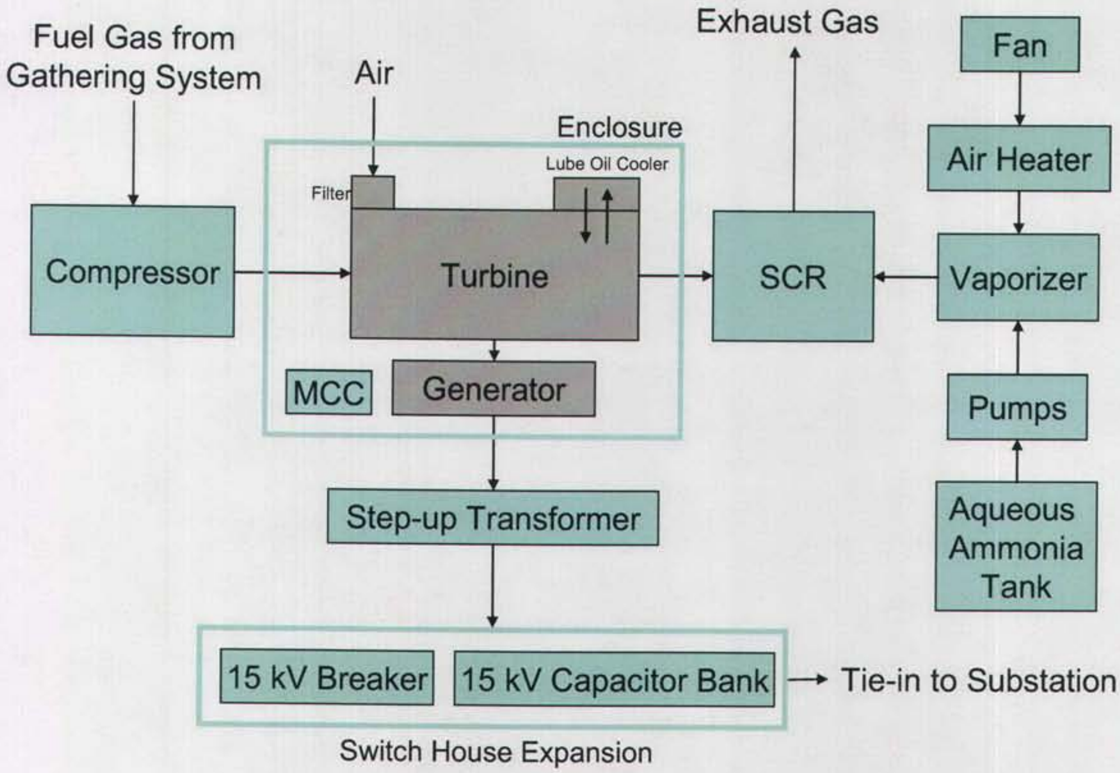
Based on the gas availability and composition, the Kawasaki GPB15 was the model selected as a representative choice for CT technology. The CT is delivered on a skid with complete indoor enclosure and major components such as the lube oil system and programmable logic control (PLC) system included and preassembled. Additionally, this model was quoted by the manufacturer with an extended pre-wired auxiliary electrical skid containing a 52G output breaker, variable frequency drive start, fire and gas detection system, motor control center, and turbine and generator control panels.

Figure 3-1: Kawasaki GPB15 Combustion Turbine

3.2.1 Combustion Turbine Block Flow Diagram

The Kawasaki GPB15 standard package configuration is indicated in grey on the flow diagram below. Additional equipment that is required to produce a functioning power generation system includes an outdoor enclosure, a gas compressor and optional selective catalytic reduction (SCR) equipment for control of nitrous oxide (NO_x) emissions. The optional items are shown in the teal-shaded boxes. This is a general representation only.

Figure 3-2: Combustion Turbine Block Flow Diagram

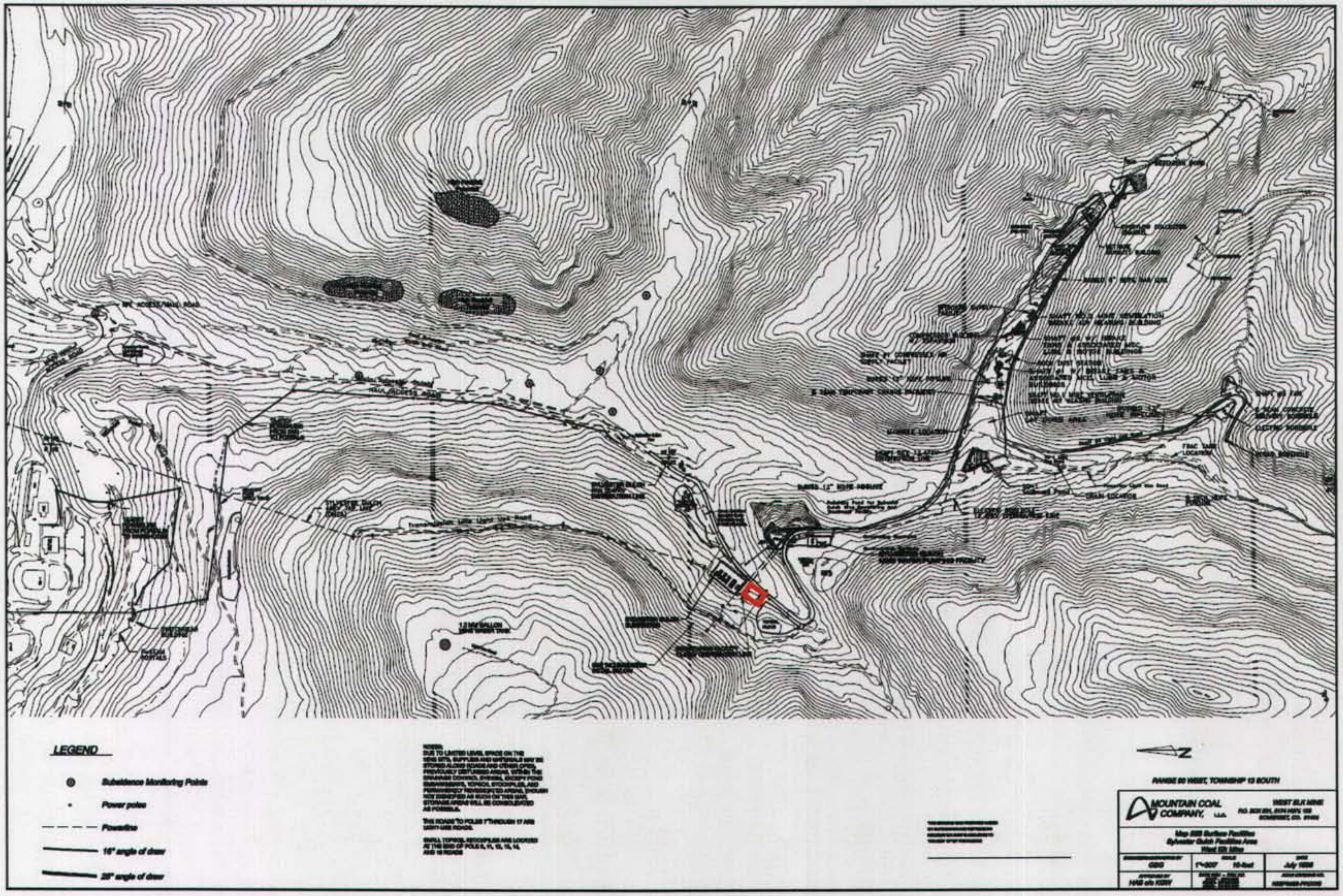


3.2.2 Combustion Turbine Site Layout

Figure 3-3 provides a general arrangement drawing of the surface facilities located at the West Elk Mine. The most probable location of future generating equipment would be near the existing Sylvester Gulch substation due to the constructability of land adjacent to the substation and the elimination of overhead transmission lines to connect the generator to the substation.

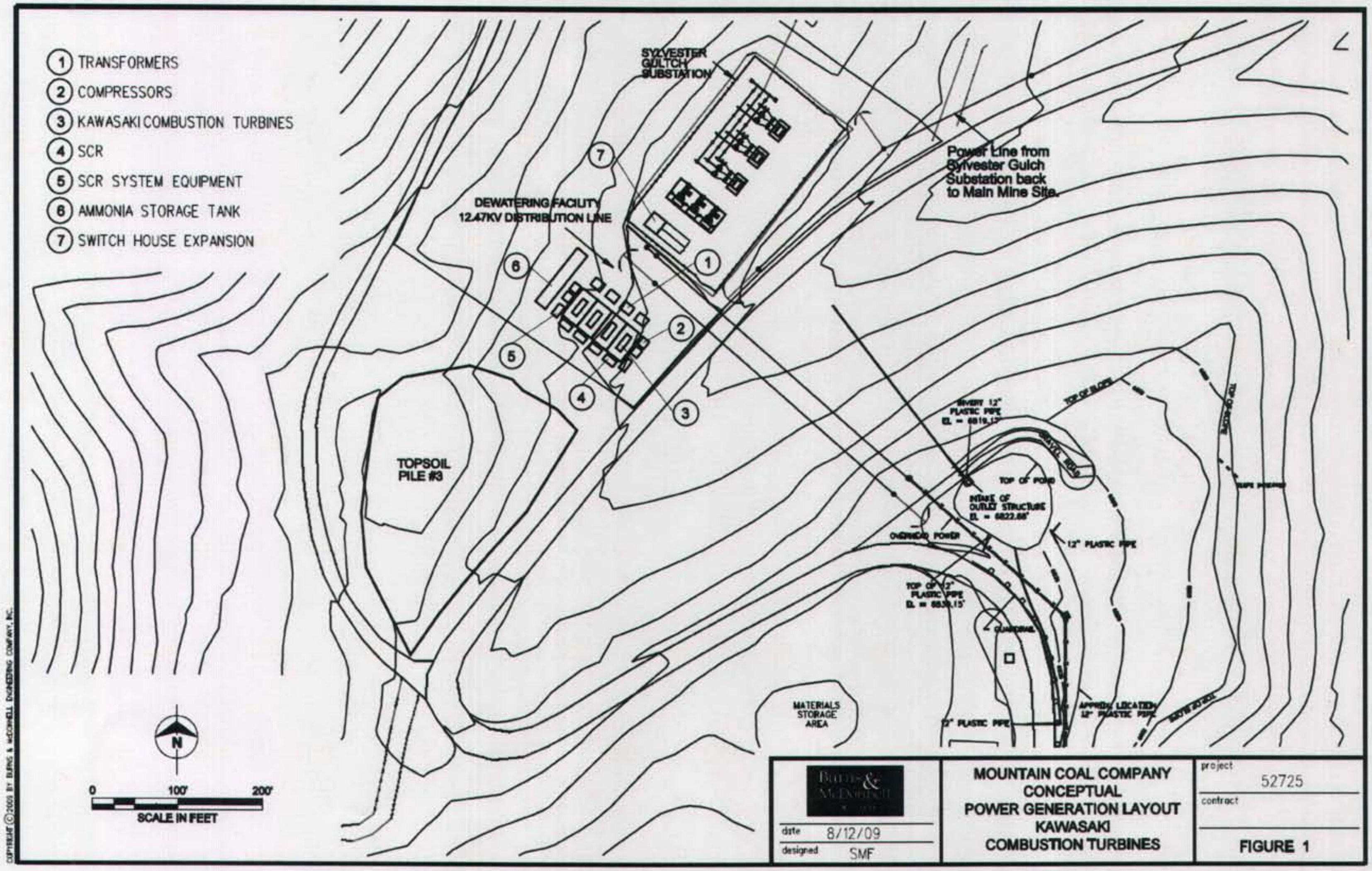
Figure 3-4 provides a site layout that is representative of four GPB15 turbines. With the amount of CMM available as described in Section 3.1, there is enough methane to supply fuel for four CTs.

Figure 3-3: West Elk Mine Surface Facilities (Generating Facilities Location Shown)



The approximate location of future generating equipment is indicated by the red box on the Surface Facilities general arrangement.

Figure 3-4: Combustion Turbine Site Layout



3.2.3 Combustion Turbine Performance

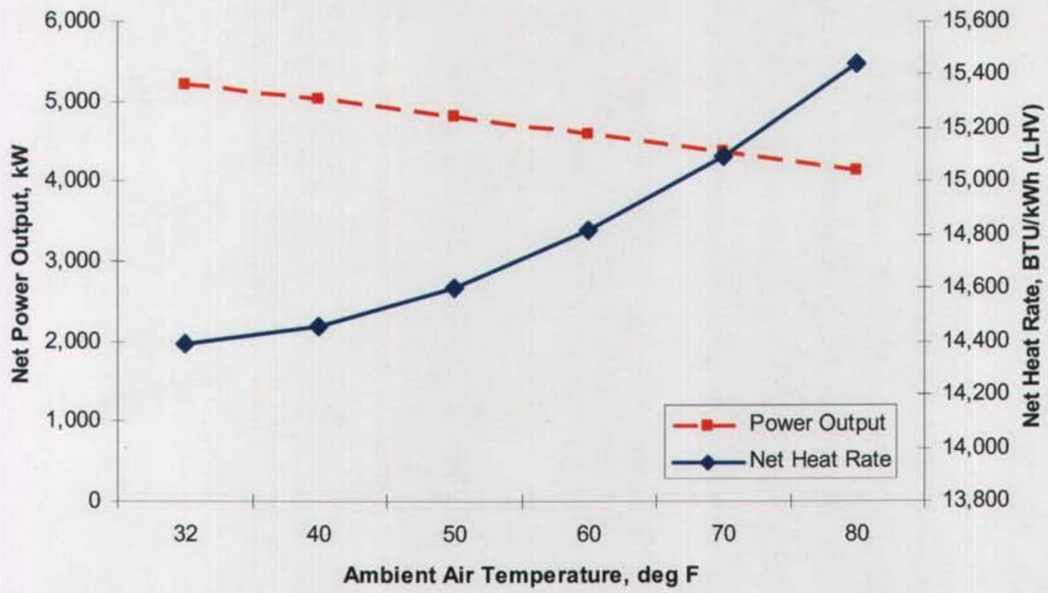
The Kawasaki GPB15 is rated for 1.44 MW under standard ISO conditions (Sea level, 59°F). A site elevation of 7,000 ft combined with balance of plant and engine auxiliary loads reduces the output by 20% to 1.15 MW, or 4.60 MW for four units (at 59°F). In addition ambient air temperature and loads will alter the power output and the fuel requirements as shown below.

Table 3-2: CT Power Output and Fuel Requirement

Varying Temperature @ 100% Load	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Ambient Temperature (deg F)	32	40	50	60	70	80
Aux Load (kW)	158	155	150	144	139	134
Net Output (kW)	5,201	5,041	4,827	4,603	4,373	4,141
Net Plant Heat Rate, LHV (Btu/kWh)	14,388	14,454	14,601	14,816	15,096	15,440

Varying Load @ 59°F	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7
Load Ratio (%)	100	90	80	70	60	50	40
Aux Load (kW)	215	197	179	162	144	126	108
Net Output (kW)	4,577	4,116	3,654	3,193	2,731	2,270	1,808
Net Plant Heat Rate, LHV (Btu/kWh)	14,672	15,024	15,525	16,240	17,279	18,836	21,308

Figure 3-5: Temperature Effects on CT Power Output and Heat Rate



The site elevation and increase in ambient air temperature above standard conditions have the most detrimental effect on the turbine's power output. For the purposes of the economic analysis discussed in

Section 5.0, a net output of 1.1 MW and heat rate of 14,900 Btu/kWh were utilized for each of the four turbines.

3.2.4 Combustion Turbine Capital and Operating Cost Estimates

A capital cost estimate for a power generating facility utilizing CT technology was developed. The estimate is for the CT power block as well as auxiliary systems. The total power plant includes the combustion turbine, software package, electrical hardware, mechanical piping, site preparation and building, and SCR equipment along with various overhead costs such as equipment delivery, installation, engineering, and project management.

Table 3-3: Combustion Turbine Capital Cost

Kawasaki GPB15		Four Turbines
Turbine		
Turbine Package		6,000,000
Remote Operation Software		9,000
Start-up and Commissioning (6 weeks)		199,000
Transport from Houston		20,000
Installation by Crane		35,000
Mechanical		
Miscellaneous Piping		18,000
Ductwork		20,000
Electrical		
MCCs and Underground Cable		1,482,000
Structural		
Turbine Foundation, slab on grade		221,000
Enclosure		150,000
Switchgear Bldg Foundation Expansion		86,000
Civil		
Site Prep		375,000
Final Grading		28,000
Emission Controls		
SCR		600,000
Piping		42,000
Ammonia Storage Tank, 23,500 gal.		1,122,000
Ammonia Tank Containment		32,000
Fan, Heater and Vaporizer		560,000
Electrical Hookup for Ammonia Skids		125,000
Foundation for Skids		12,000
Subtotal ($)		**11,136,000**
Engineering and Management Cost	10%	1,114,000
Overhead	18%	2,205,000
Owner's Cost inc. Contingency	20%	2,891,000
TOTAL Capital Cost (2009$)		**$17,300,000**
Cost per kW ($/kW)		**$3,760**

Table 3-4 presents operating costs for the CT plant. Operators are shared with the well and collection system as described in Section 2.1.2. Costs for the operators are reflected in the well and collection system operating cost estimate and not included in the table below.

Table 3-4: Combustion Turbine Operational Costs

	Four Turbines
Fixed O&M Including Lube Oil and Filters	470,000.00
Variable O&M - Ammonia	88,000.00
TOTAL Annual O&M Cost (2009$)	**$558,000**

3.3 POWER GENERATION WITH RECIPROCATING ENGINE(S)

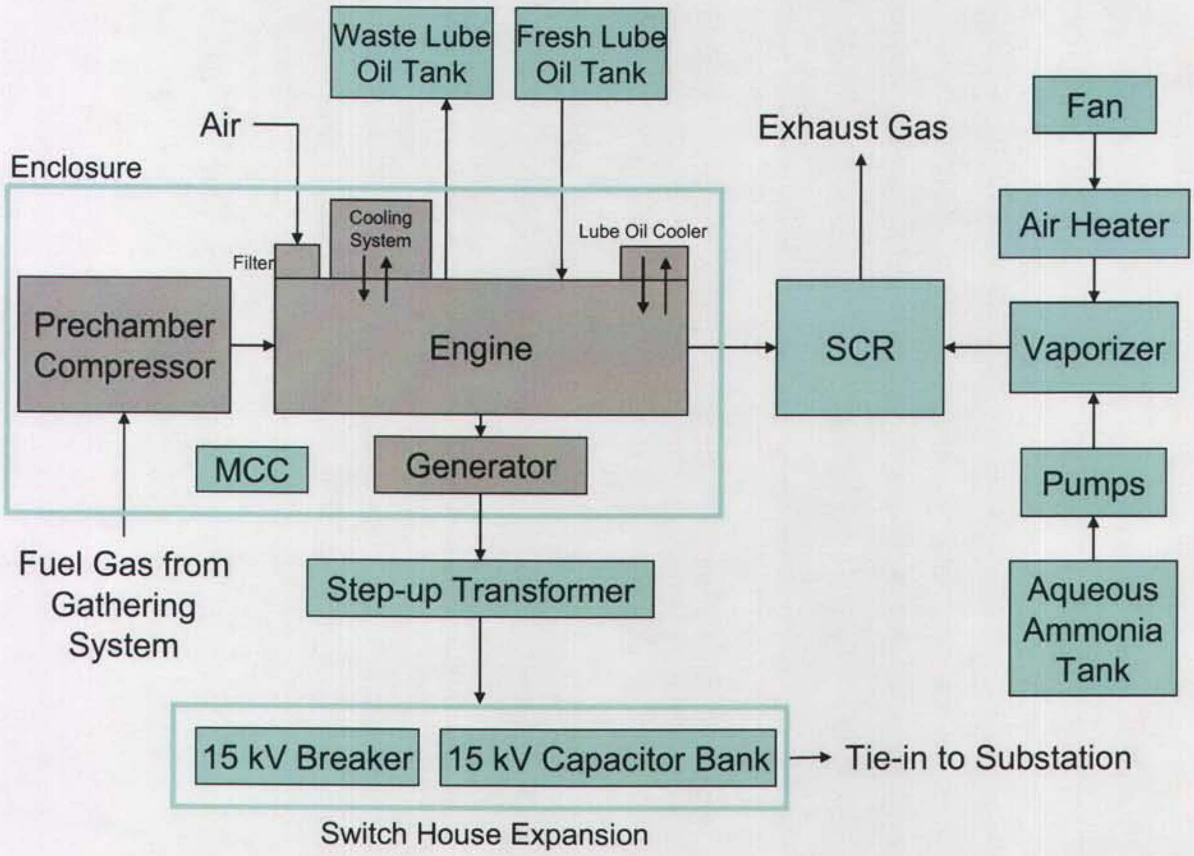
Based on gas availability and composition, the GE Jenbacher JMS 620 GS-N.L was selected as the representative model for reciprocating engine technology. The engine is delivered on a skid with major components such as the pre-chamber compressor, the lube oil system and PLC system included and preassembled. Unlike the Kawasaki CT, the engine does not have an indoor enclosure or a pre-wired electrical skid with breaker and Mountain Coal, however it does include a pre-chamber compressor which reduces the required gas inlet pressure to 1-2 pounds per square inch gauge (psig) versus the 200 psig required by the Kawasaki turbine. Similar to the CT cost estimate, a building enclosure has been included in the engine cost estimate for protection from inclement weather.

Figure 3-6: GE Jenbacher JMS 620

3.3.1 Reciprocating Engine Block Flow Diagram

The GE Jenbacher standard package configuration is indicated in grey on the flow diagram below. Additional equipment that is required to produce a functioning power generation system, including the optional SCR module, is indicated in teal. As mentioned above, the JMS 620 does not require a separate compressor; however, it does require lube oil tanks due to greater oil usage. This is a general representation only.

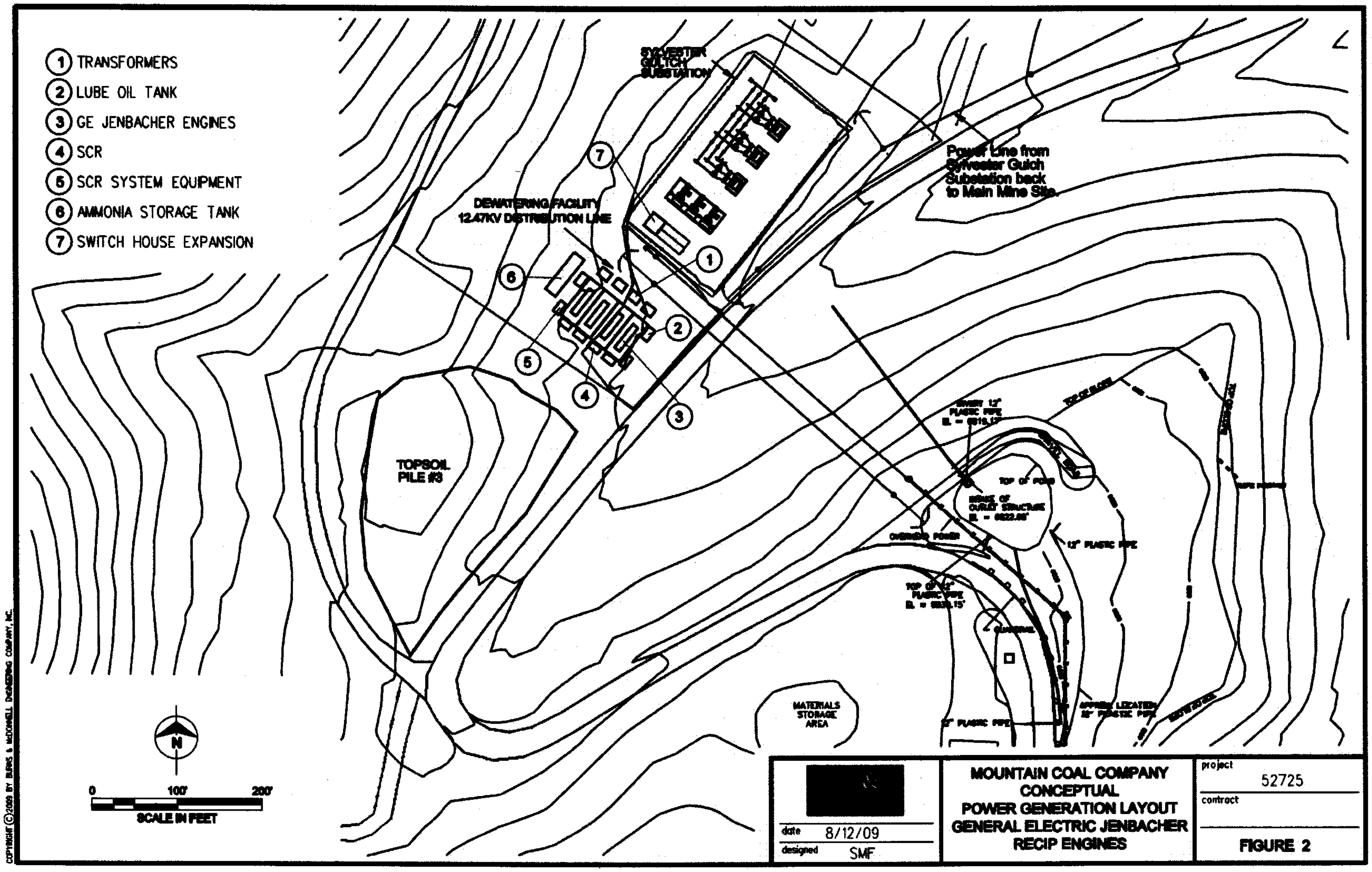
Figure 3-7: Reciprocating Engine Block Flow Diagram



3.3.2 Reciprocating Engine Site Layout

Figure 3-8 provides a site layout that is representative of four JMS 620 engines. With the amount of CMM available as described in Section 3.1, there is sufficient methane available to support four engines.

Figure 3-8: Reciprocating Engine Site Layout



3.3.3 Reciprocating Engine Performance

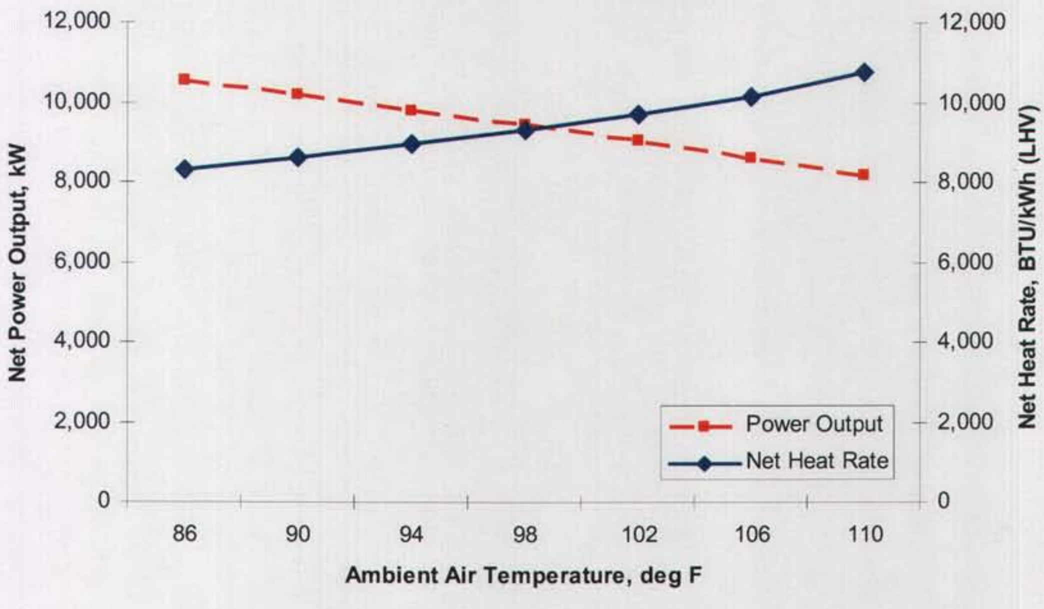
The GE Jenbacher JMS 620 is rated for 3 MW under standard ISO conditions (Sea level, 59°F). A site elevation of 7,000 ft combined with balance of plant and engine auxiliary loads reduces the output by 12% to 2.64 MW, or 10.5 MW for four units. In addition, ambient air temperature and loads will alter the power output and the fuel requirements as shown below.

Table 3-5: Reciprocating Engine Power Output and Fuel Requirement

Varying Temperature @ 100% Load	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7
Ambient Temperature (deg F)	86	90	94	98	102	106	110
Aux Load (kW)	243	234	226	217	208	199	188
Net Output (kW)	10,557	10,182	9,806	9,431	9,056	8,633	8,168
Net Plant Heat Rate, LHV (Btu/kWh)	8,316	8,623	8,953	9,309	9,695	10,169	10,748

Varying Load @ 86°F	Case 1	Case 2	Case 3
Load Ratio (%)	100	75	50
Aux Load (kW)	243	182	120
Net Output (kW)	10,557	7,890	5,204
Net Plant Heat Rate, LHV (Btu/kWh)	8,316	8,623	9,278

Figure 3-9: Temperature Effects on Engine Power Output and Heat Rate



The increase in ambient air temperature above standard conditions has the most detrimental effect on the engine's power output. Derating due to altitude also impacts the engine, but it is not as pronounced as with the CT.

3.3.4 Reciprocating Engine Capital and Operating Cost Estimates

A capital cost estimate for a power generating facility utilizing reciprocating engine technology was developed. The estimate is for the engine power block as well as auxiliary systems. The total power plant includes the engine, software package, electrical hardware, mechanical piping, lube oil tanks, site preparation and building, and SCR equipment plus various overhead costs such as equipment delivery, installation, engineering, and project management.

Table 3-6: Reciprocating Engine Capital Cost

GE Jenbacher JMS 620		Four Engines
Engine		
Engine Package		6,520,000
Remote Operation Software		9,000
Start-up and Commissioning (10 days)		78,000
Transport from Houston		20,000
Installation by Crane		35,000
Mechanical		
Cooling Piping		89,000
Gas Train Piping		18,000
Lube Oil Piping		36,000
Miscellaneous Piping		13,000
Ductwork		39,000
Lube Oil Tank, 1000 gal.		35,000
Electrical		
Wiring, Cable Tray, Small Transformers		255,000
MCCs and Underground Cable		1,482,000
Structural		
Engine Foundation		306,000
Enclosure		289,000
Switchgear Bldg Foundation Expansion		86,000
Civil		
Site Prep		375,000
Final Grading		28,000
Emission Controls		
SCR		1,600,000
Ammonia Piping		42,000
Ammonia Storage Tank 11,000 gal.		682,000
Ammonia Tank Containment		23,000
Fan, Heater and Vaporizer		560,000
Electrical Hookup for Ammonia Skids		125,000
Foundation for Skids		12,000
Subtotal ($)		**$12,757,000**
Engineering and Management Cost	10%	1,276,000
Overhead	18%	2,526,000
Owner's Cost inc. Contingency	20%	3,312,000
TOTAL Capital Cost (2009$)		**$19,900,000**
Cost per kW ($/kW)		**$1,890**

Table 3-7 presents operating costs for the reciprocating engine plant. Operators are shared with the well and collection system as described in Section 2.1.2. Costs for the operators are reflected in the well and collection system operating cost estimate and not included in the table below.

Table 3-7: Reciprocating Engine Operational Costs

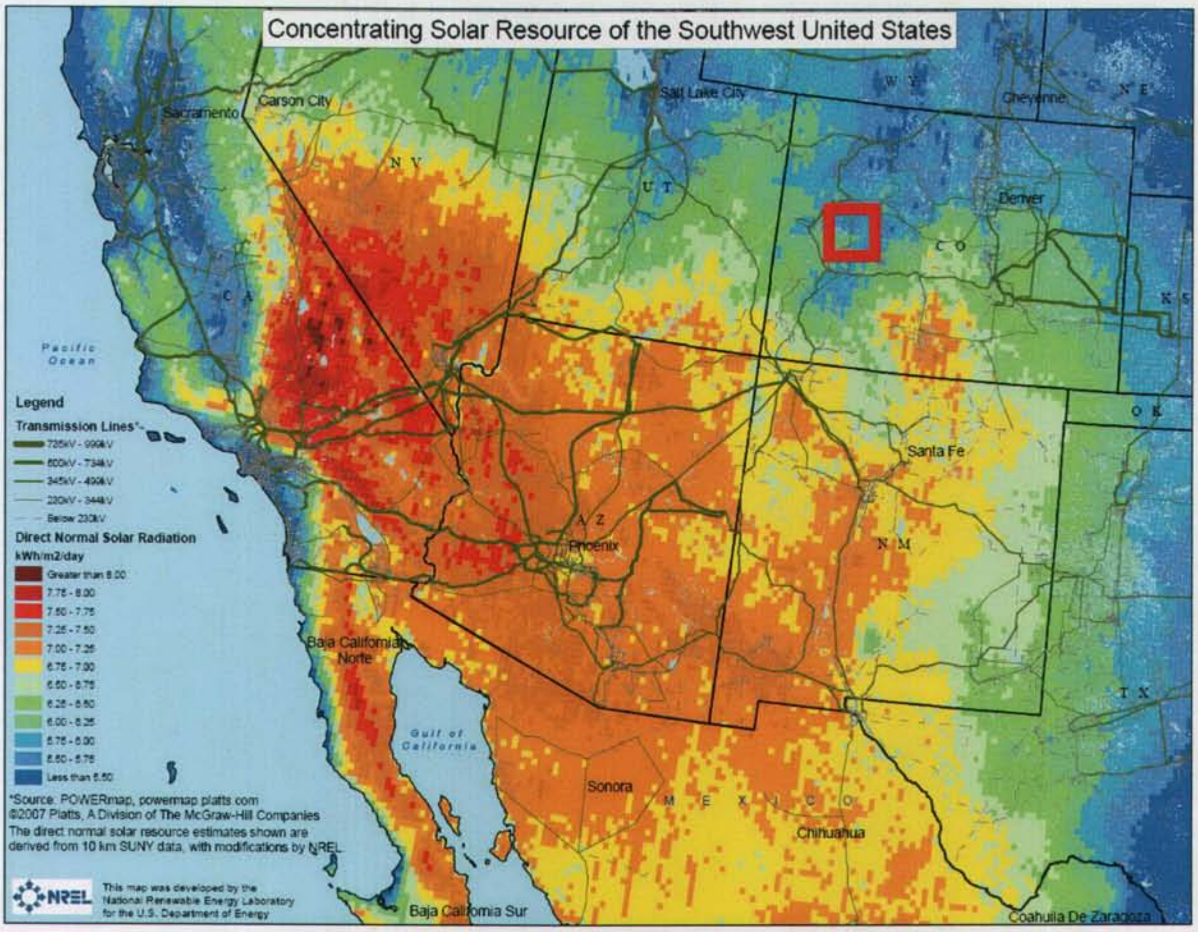
	Four Engines
Fixed O&M Including Lube Oil and Filters	867,000
Variable O&M - Ammonia	41,000
TOTAL Annual O&M Cost (2009$)	**$908,000**

3.4 POWER GENERATION WITH INTEGRATED SOLAR TECHNOLOGY

In addition to the beneficial use options described previously in this report, power generation with integrated solar technology was initially reviewed but was removed from further consideration due to limitations at the mine that would preclude development of an integrated solar plant. Conceptually, an integrated solar plant would utilize energy from solar radiation during daylight hours to produce steam for power production. During nighttime hours or periods with low solar radiation, CMM would be fired in a boiler to generate steam. The systems would work in conjunction to generate power that could be sold to the electrical grid.

To be feasible and cost effective, parabolic trough power plants require relatively large tracts of nearly level open land with high solar radiation intensity. The National Renewable Energy Laboratory (NREL) performed an analysis of the southwestern United States, including Colorado, to identify optimal sites from solar intensity and suitable terrain perspectives. The following figure was developed by NREL to show the direct normal solar radiation intensity for the Southwest. The approximate location of the mine is depicted by the red box.

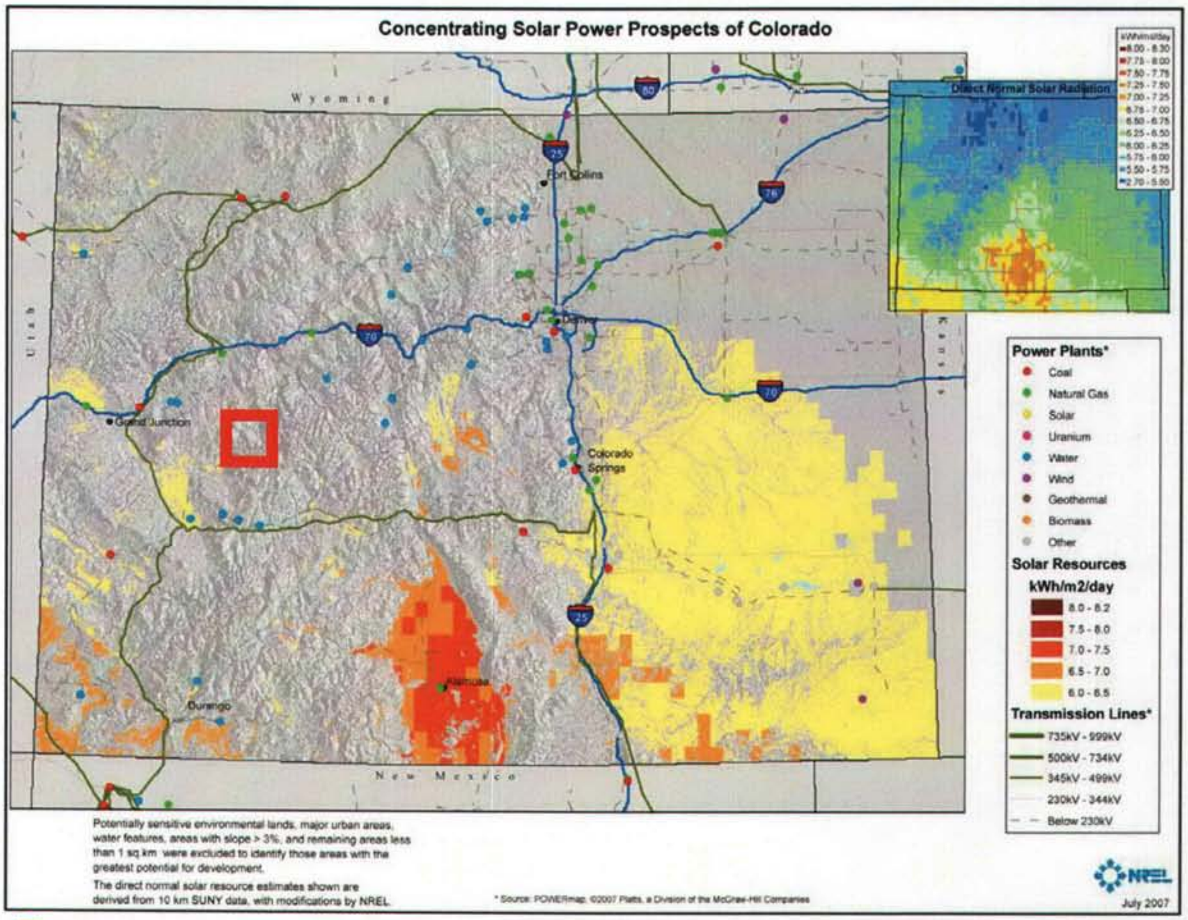
Figure 3-10: Solar Intensity Map



Approximate location of West Elk Mine

In an integrated solar power generating facility, the solar collector field is comprised of many rows of mirrored parabolas, aligned on a north-south axis. The parabolic troughs require level land, with less than 1% slope desirable. NREL developed geographic information system-based maps that integrate the solar intensity information provided in the figure above with terrain data. The result is a map showing locations that would be suitable for solar troughs based on terrain with less than 3% slope. A 3% slope is more than what is desirable for solar troughs, but site grading can reduce slope. The figure below presents the results of this analysis for Colorado.

Figure 3-11: Suitable Concentrating Solar Site Locations



Approximate location of West Elk Mine

Based on review of the NREL siting analysis, the location of the Mine in a mountainous region with marginal solar radiation intensity results in limited applicability of integrated solar at the site.

* * * * *

AIR EMISSIONS AND KEY PERMITS

4.0 AIR EMISSIONS AND KEY PERMITS

In order to determine if the project has any fatal flaws with respect to emissions and permitting, an overview of key construction and operating permits/approvals was completed. The review focused on the following project aspects and permit requirements:

- Air emissions
- Water supply and discharge
- National Environmental Policy Act (NEPA)
- Local restrictions (noise, setback, etc.)
- Site clearances (threatened and endangered species, cultural, wetlands, etc.)

4.1 AIR EMISSIONS

4.1.1 Construction Permit

The estimated air emissions from four Kawasaki combustion turbines operating at average conditions and full load for 8,760 hours per year results in the following emissions:

Table 4-1: Potential Emissions from Kawasaki, GPB 15, No SCR

Pollutant	PPM	T/yr
CO	200.0	40.4
NO_x	640.0	212.0

Note: Emissions of four units

Table 4-2: Potential Emissions from Kawasaki, GPB 15, With SCR

Pollutant	PPM	T/yr
CO	200.0	40.4
NO_x	100.0	33.2

Note: Emissions of four units

The estimated air emissions from four GE Jenbacher reciprocating engines operating at full load for 8,760 hours per year results in the following emissions:

Table 4-3: Potential Emissions from GE Jenbacher, JMS 620 GS-N.L, No SCR

Pollutant	g/bhp-hr	T/yr
CO	10.0	363.6
NO_x	4.4	160.0
PM_{10}	0.12	4.36

Note: Emissions of four units

Table 4-4: Potential Emissions from GE Jenbacher, JMS 620 GS-N.L, With SCR

Pollutant	g/bhp-hr	T/yr
CO	8.4	305.3
NO_x	2.12	77.2
PM_{10}	0.12	4.36

Note: Emissions of four units

Construction permits issued by the Colorado Department of Public Health and Environment (CDPHE) are required for a facility with uncontrolled actual emissions of any criteria pollutant equal to or greater than the amounts listed in the Table 4-5.

Table 4-5: Threshold Emission Levels for Triggering Construction Permit

Criteria Pollutant	Attainment Area: Uncontrolled Actual Emissions (tons/yr)
Volatile Organic Compounds	5
PM10	5
Total Suspended Particulates	10
Carbon Monoxide	10
Sulfur Dioxide	10
Nitrogen Oxides	10
Lead	200 lb/yr
Other Criteria Pollutants	2

Based on the anticipated emission levels and continuous operations, a construction permit will be required for either generating option, even with the inclusion of SCR equipment for NO_x and CO reduction. Application for a construction permit should be submitted approximately six months prior to the start of construction.

4.2 KEY PERMITS AND CLEARANCES

4.2.1 Operating Permit

If emissions, resulting from all sources at the mine, of any pollutant are greater than 100 tons annually, the facility is considered a "major source". Considering the generation-related sources alone, more than

100 tons per year could be emitted from four Kawasaki combustion turbines without SCR, or four Jenbacher engines either with or without SCR. A major source requires an operating permit in addition to the construction permit.

Any source or group of sources operating under a common standard industrial classification code, that emits, or has the potential to emit, more than 100 tons of any regulated air pollutant per year will be required to have an operating permit. This permit is required to be in place within twelve months after receiving the construction permit, but is often processed by the Colorado Department of Public Health and Environment, Air Pollution Control Division, at the same time as the construction permit. Applicability is based on total facility emissions.

In addition, any source that emits, or has the potential to emit, more than ten tons per year of a hazardous air pollutant (HAP), or more than 25 tons per year of a combination of hazardous air pollutants, will be required to have an operating permit. There is no indication that the emissions resulting from either generator type would result in emissions of HAPs above these levels.

Although not a specific regulatory limit, acquisition of an operating permit (or a major source construction permit) typically includes review of the application by Federal Land Management agencies. The Forest Service has historically been concerned abut the potential for visibility impacts resulting from $PM_{2.5}$ emissions. If an operating permit is required, it is expected that the project will need to demonstrate that Best Available Control Technology is applied to control potential emissions of precursors to $PM_{2.5}$ (i.e., NO_x, SO_2, and volatile organic compounds).

In summary, an operating permit may be required if there are significant emissions already resulting from the rest of the mine operation, if four CTs without SCR are installed, or if four reciprocating engines with or without SCR are installed.

4.2.2 Water Supply and Discharge

There is no indication that significant amounts of water will be required for operation of either type of generating equipment. No significant water discharge is associated with operation of either system. Limited water needs could be supplied through existing mine operations and no permits would be required for water supply or discharge from the installed generating equipment.

4.2.3 NEPA

The environmental impact statement (EIS) for the mine expansion was approved in 2007 and included venting of methane. The plan for gas collection is different than the system that was included in the EIS and may require new action by the Forest Service to approve installation of the gas collection system and the associated installation of CTs or engines. The decision is based on the requirement for a major federal action. If an application needs to be made to the Forest Service, or another Federal agency, prior to construction of the well, gas collection, and combustion systems, then NEPA may apply.

4.2.4 Local Restrictions

Gunnison County has county land use regulations and has authority to review the planned activities. The county has exempted coal mine venting that is essential to the coal mine operation. Coal mine methane venting from a mine that is in compliance with these regulations and that is an integral and essential component of the coal mining operation shall not be subject to these regulations or any other County regulations otherwise applicable to oil and gas drilling and production and such methane can be used by the operator on-site.

Below is a summary of several aspects of the Land Use Regulations that would be potentially applicable.

- **Truck Noise:** Mine haul trucks associated with expansions of Coal Mining Operations shall comply with Section 5-505 F.6 of the Gunnison County Land Use Resolution.

- **Setbacks:** Surface area disturbed by the expansion shall fall within the following setbacks:

    a. Federally, State, or Locally Dedicated Open Space or Conservation Areas: No surface area disturbance caused by the expansion of the Coal Mining Operations shall occur in whole or in part closer than 1,000 feet from a permanently dedicated federal, state, or local open space or conservation area unless a smaller setback has been approved by the federal, state or local entity with jurisdiction over the open space or conservation area.

The County also has regulations applicable to the generation of electricity for sale:

- In addition to the general criteria set forth in Section 5-102 (1), the following additional criteria apply to permit applications for private power projects:

- If the proposed project is intended to supply power to persons other than the applicant, the scope and nature of the proposed project must not duplicate services within the County;

- If the purpose and need for the proposed project are to meet the needs of an increasing population within the county, area and community development and population trends must clearly demonstrate a need for such development.

In summary, a preconstruction meeting should be held with the Gunnison County Planning Department to discuss the project and specific requirements.

4.2.5 Site Clearances

The conditions established by the EIS for the methane venting project could affect this project. This includes the items discussed in the following sections.

CULTURAL

The recent EIS for the venting of coal mine methane (CMM) includes the following provisions:

> *122. Prior to the construction process, an intensive cultural resources survey would be completed by the Proponent, at their expense, on all areas proposed for surface disturbance if it has not already been inventoried per requirements of the Standard Notice for Lands Under Jurisdiction of the USDA attached to the leases.*
>
> *123. During project implementation, in the event of an inadvertent discovery of any other cultural resources not covered under NAGPRA (above), work should cease and an archaeologist should be notified to investigate the resource. Any cultural resources located will be brought to the immediate attention of the Forest Service and will be left intact until directed to proceed. All data and materials recovered will remain under the jurisdiction of the U.S. Government.*

The requirement from the EIS could possibly apply to the area of disturbance associated with the installation of equipment intended to gather and combust the CMM. To be conservative, if the area identified for construction has not been previously disturbed, it should be surveyed for cultural resources in accordance with the EIS.

T&E

Similarly, the recent EIS for the venting of CMM includes the following provisions related to Threatened and Endangered (T&E) species:

> *The impacts on lynx would result from noise and other activity related disturbances that result from road construction or well installation. While there would be short-term habitat loss, it would be relatively minor given the amount of available habitat within the LAU.*

The equipment used to combust the CMM and drive the generators will add noise to the area. This potential impact was not evaluated in the EIS. Consultation with the Colorado Division of Wildlife should be held regarding the potential for the proposed project to impact T&E species.

WETLANDS

The proposed location near the existing Sylvester Gulch substation site has not been identified as a wetland and it is not anticipated that any wetlands would be impacted by the installation of generating equipment at this location.

STORMWATER RUNOFF

Disturbance of greater than one acre requires a Stormwater Construction Permit, and as a result, a Stormwater Management Plan must be developed. The permit application should be submitted at least ten days prior to construction. Final site grading will need to consider stormwater runoff and stormwater retention due to the potential for oil contamination.

* * * * *

PROJECT ECONOMIC SUMMARY

5.0 PROJECT ECONOMIC SUMMARY

In order to compare the economics of the multiple beneficial uses of CMM in flaring to destroy methane, power generation, and processing to yield natural gas, an economic pro forma model was developed. The model utilized various financial inputs and project-related costs and revenues to estimate an internal rate of return (IRR) and net present value (NPV) for each of the beneficial use alternatives. The following sections describe the modeling inputs, results, and key sensitivities.

5.1 MODEL INPUTS

- Financing Inputs
  - Debt & Equity financing blend and costs supplied by Mountain Coal, see accompanying Confidential Report for a discussion of the methodology.
  - Weighted Average Cost of Capital (WACC)
    - 10.99%
    - IRR hurdle for project consideration is equal to WACC
  - Construction Financing Fees – 0.5%
  - Permanent Financing Fees – 2.875%
  - Debt Financing Term – 10 Years
  - Book Depreciation – 10 Years Straight Line
- Economic and Project Inputs
  - Commercial Operations Date (COD) – January of 2012
  - Escalation Rate – 3.0%
  - Property Tax Rate – 0.5%
  - Insurance Rate – 0.10%
  - Income Tax Rate – 25%
  - Bureau of Land Management (BLM) Royalty Payment – 12.5%
- Fuel Cost Inputs
  - Rockies gas forecast was provided by Arista. The forecast is used to calculate the BLM royalty payment.
- Capital Cost and O&M Inputs – See Sections 2.0 and 3.0 (summarized below)

Table 5-1: Capital Cost and O&M Summary

Beneficial Use Option	Capital Cost (2009$)	Fixed O&M (2009$)
Well and Collection System	$12,107,000	$2,118,000
Flare[1,2]	$450,000	-
Generation[1, 3]		
Combustion Turbines	$17,300,000	$558,000
Reciprocating Engines	$19,900,000	$908,000
Gas Processing[3]	$22,836,000	$3,068,000

[1]Staffing for generation and flaring options is included in the well and collection system fixed O&M
[2]Flaring option also requires installation of gathering system (either the base system or alternate configuration)
[3]Generation and gas processing options also require installation of gathering system and flare

- Revenue Inputs
    - Capacity Credit – $0.00 $/kW-mo (plant operation may be intermittent, so capacity cannot be guaranteed)
    - Energy Sales Value – $71/MWh base input. Energy value is varied in the sensitivity analysis to gauge its impact on IRR.

5.2 MODEL RESULTS

In order to determine IRR and NPV, the model utilized key inputs as described in the previous section to estimate project expenses and revenues over the 10-year period from 2012 to 2021, resulting in a cash flow projection for each beneficial use option. Key expenses for the project included gas royalty payments to the BLM, principal and interest expenses for the debt required to finance the project, O&M expenses including staffing costs, income taxes, and various expenses such as insurance and property taxes. Revenue streams for the project were produced from the sale of energy for options that include generation and the sale of natural gas for the gas processing option. The potential sale of CO_2 offsets generated by the destruction or conversion of methane in all options is discussed separately.

Table 5-2 provides a summary of each option, including operational data, revenue requirements, expected revenues based on the assumptions provided in Section 5.1, and IRR/NPV results.

Table 5-2: Economic Model Summary Results

	Option 1 Flaring System		Option 2 Power Generation - CTs		Option 3 Power Generation - Recips.		Option 4 Gas Processing	
Net Project Output (kW)	NA		4,400		10,560		NA	
Net Heat Rate, LHV (Btu/kWh)	NA		14,900		8,320		NA	
Total Capital Cost (2009$)	Well/Collection - $12,107,000 Flaring System - $450,000		Well/Coll./Flare - $12,557,000 CTs - $17,300,000		Well/Coll./Flare - $12,557,000 Recip. Engines - $19,900,000		Well/Coll./Flare - $12,557,000 Gas Processing - $22,836,000	
Estimated Annual Generation (MWh)	NA		32,762		78,630		NA	
Annual CO_2 Equivalent Destroyed (tonnes)	229,990		229,990		229,990		229,990	
Year	Expenses ($000)	Revenue ($000)	Expenses ($000)	Revenue ($000)	Expenses ($000)	Revenue ($000)	Expenses ($000)	Revenue ($000)
2012	4,622	NA	8,925	2,492	9,917	5,981	10,292	3,764
2013	4,640	NA	8,893	2,567	9,888	6,161	10,255	3,831
2014	4,655	NA	8,852	2,644	9,849	6,346	10,207	3,897
2015	4,667	NA	8,804	2,723	9,802	6,536	10,150	3,988
2016	4,676	NA	8,736	2,805	9,734	6,732	10,071	4,012
2017	4,680	NA	8,670	2,889	9,670	6,934	9,994	4,170
2018	4,679	NA	8,581	2,976	9,579	7,142	9,891	4,248
2019	4,673	NA	8,482	3,065	9,480	7,356	9,776	4,376
2020	4,662	NA	8,365	3,157	9,362	7,577	9,641	4,507
2021	4,643	NA	8,231	3,252	9,223	7,804	9,484	4,642
IRR (%) Less than Zero = NA	NA		NA		NA		NA	
NPV ($000), 2009$	($26,170)		($35,010)		($19,892)		($35,852)	

As evident from the IRR and NPV values, none of the projects are financially viable given the baseline revenue inputs. Revenues from the sale of electricity and natural gas are significantly less than the total expenses that result from construction and operation of each project. Of the options analyzed, reciprocating engines are the most economical. However, even if energy from the units can be sold for \$71/MWh, the NPV of the reciprocating engines is negative \$19.9 million.

5.2.1 Alternate Flaring Location

As described in Section 2.2.1.1, an alternate flaring location could potentially be utilized if power generation and gas processing are not performed or retained as future options. With this scenario, if flaring is performed at a location closer to the collection system, the capital and operating costs of the system can be reduced. The capital cost of this alternate flaring location is \$9,407,000, including the cost of the flare. The annual operating cost is \$1,498,000. However, even with reduced capital and operating costs, the NPV of this alternate option is negative \$19.1 million. Although the NPV of the alternate location is improved over flaring at the substation, the project remains uneconomical.

5.3 MODEL SENSITIVITIES

A sensitivity analysis was completed in order to gauge the impact of varying key model inputs. The two key revenue-related inputs are Energy Sales Value for the power generation options and Gas Sales Price for the gas processing option. The base energy sales value was \$71/MWh (\$76/MWh in 2012\$) and the base gas sales price was \$6.22/MMBtu (2012\$).

The \$71/MWh rate was selected as an upper bound base energy sales value because that is what the West Elk Mine currently pays for electricity supplied to the mine. This is an optimistic price target. This rate includes both energy and capacity components. The energy portion of this rate, which is the comparable component to the electrical product that would be available from onsite generation (i.e. no capacity value), is \$32.90/MWh. The Mine pays a significant capacity value premium in addition to the \$32.90 energy value so as to be able to draw power on demand. Conversely, because of wide day-to-day fluctuations in methane production from the methane drainage wells, electricity generated at the mine would have a relatively low capacity value. So, as can be seen when comparing the base model input for energy value, \$71/MWh is a significantly higher value relative to energy value rates currently paid by the mine. Review of publicly available Federal Energy Regulatory Commission transaction records indicate that more appropriate pricing may be in the mid-\$40 range. However, because those records do not disclose complete production details, and a precise rate cannot be determined without detailed negotiations with power purchasers, \$71/MWh has been used for purposes of the sensitivity analysis.

In order to gauge the IRR sensitivity to these factors, the model was run over a range of values, and the IRR was calculated for each case. Figures 5-1 through 5-3 present the sensitivity results. Note that only the power generation options are dependent upon energy sales value, and the gas processing option is dependent upon the gas sales price.

Figure 5-1: Energy Sales Value Sensitivity – CT

Figure 5-2: Energy Sales Value Sensitivity – Reciprocating Engine

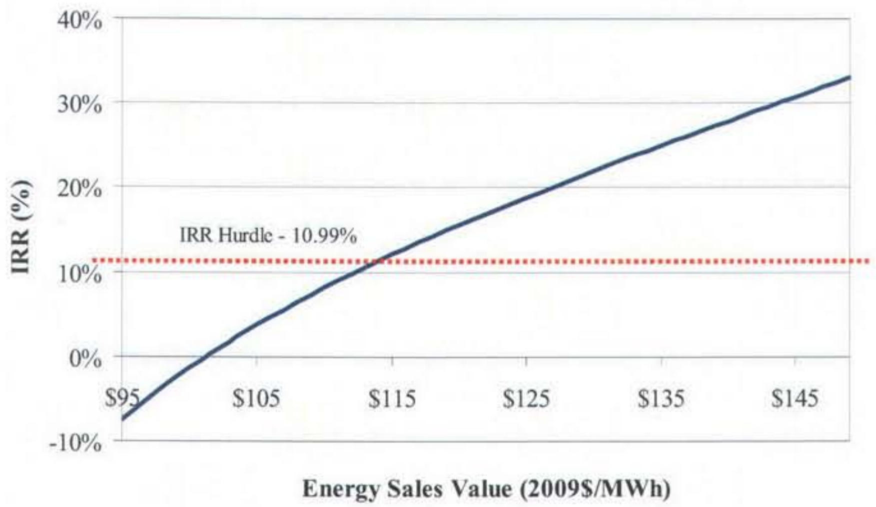
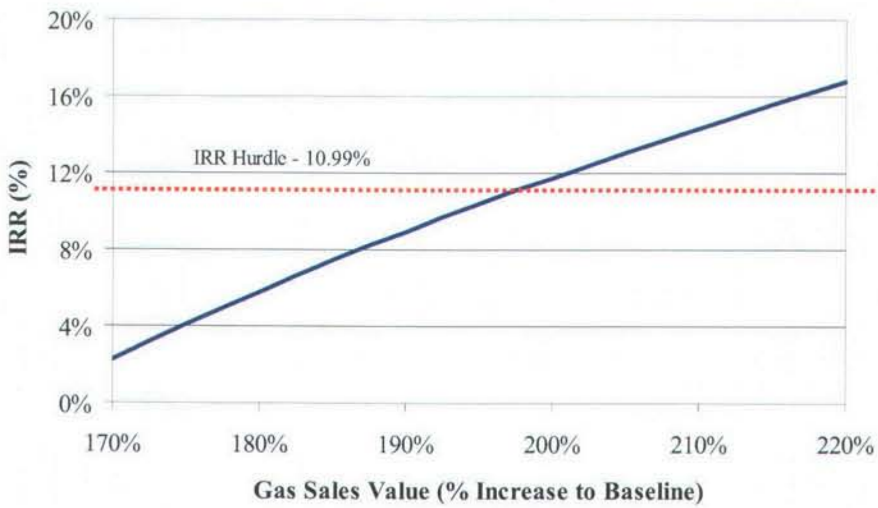


Figure 5-3: Gas Sales Price – Gas Processing Option



The energy sales sensitivity charts show that in order to meet an IRR hurdle of 10.99%, energy sales values of approximately \$246/MWh and \$114/MWh are necessary for the CT and reciprocating engine options, respectively. For the gas processing option, a 2012 gas sales value of \$18.66/MMBtu, which is triple the baseline input of \$6.22/MMBtu, is necessary to meet the IRR hurdle.

5.3.1 Carbon Offsets as a Revenue Stream

Each of the methane management options described in this report can potentially generate CO_2 offsets, as methane is combusted. Carbon markets are currently in a state of significant flux. Presently, carbon offsets are primarily bought and sold in voluntary marketplaces such as the Chicago Climate Exchange (CCX). However, draft legislation in Congress would create a federally mandated cap-and-trade system, which in theory may create a robust market in CO_2 offsets. Uncertainty regarding the contours of legislation has depressed CCX prices and affected other marketplaces as potential traders and regulated parties delay trades.

In order to gauge the impact to IRR due to revenue from potential CO_2 offset sales, the model was run over a range of offset values, and the IRR was calculated for each case. Figures 5-4 through 5-8 present the results of the analysis.

Figure 5-4: CO_2 Offset Value Sensitivity – Flaring System

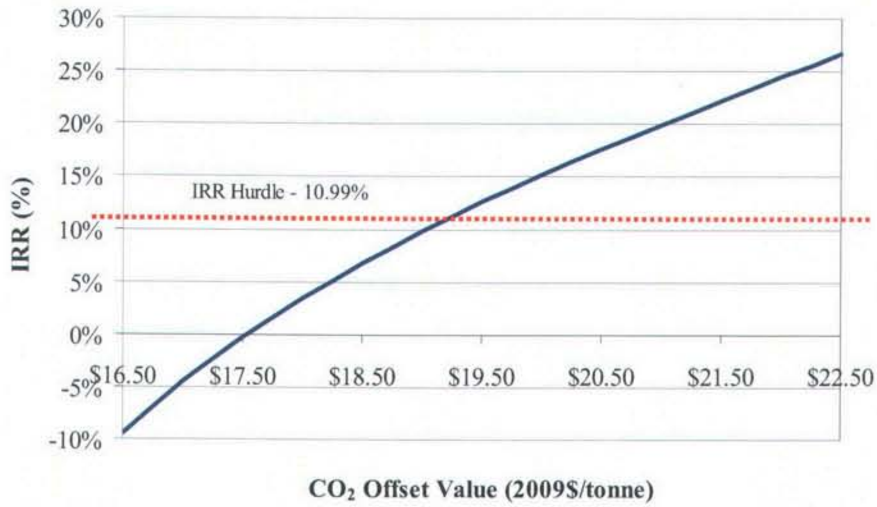


Figure 5-5: CO_2 Offset Value Sensitivity – Alternate Flaring System

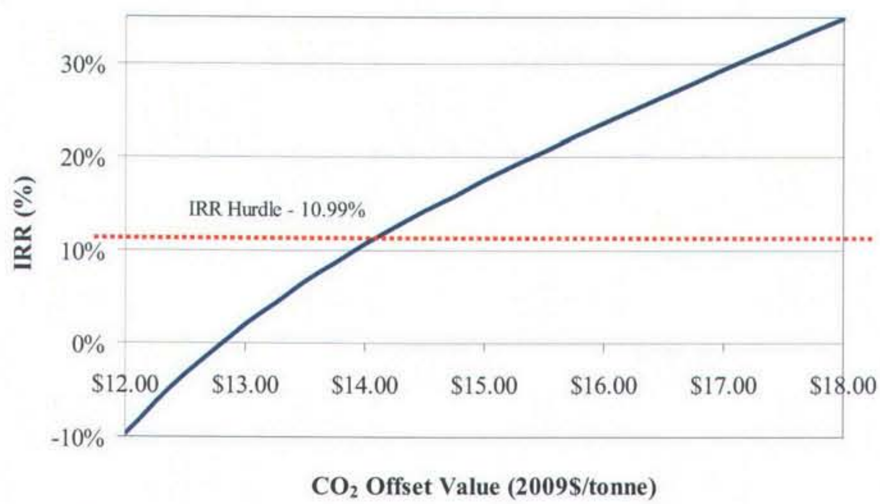


Figure 5-6: CO_2 Offset Value Sensitivity – Combustion Turbine

Figure 5-7: CO_2 Offset Value Sensitivity – Reciprocating Engine

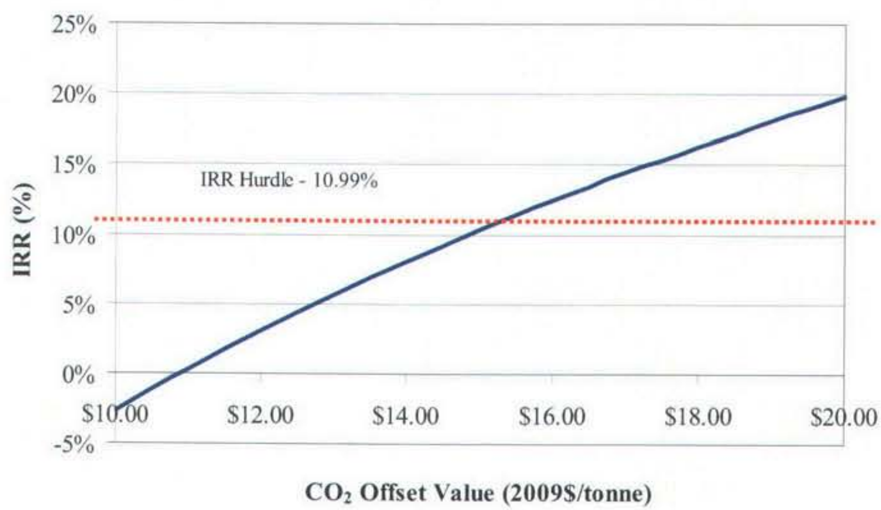
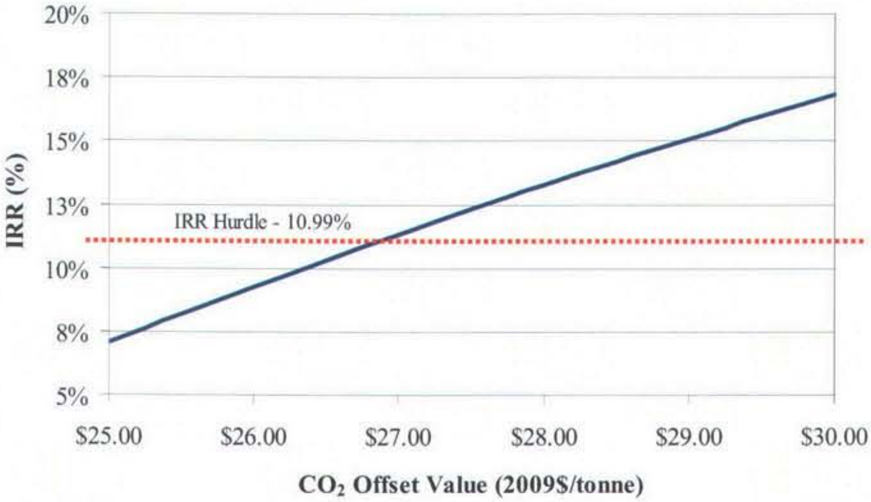


Figure 5-8: CO_2 Offset Value Sensitivity – Gas Processing



The CO_2 offset sensitivity charts show that offset values will need to reach at least \$15.50/tonne before the reciprocating engine option meets the IRR hurdle (all sensitivities assume \$71/MWh for energy sales value). At \$19.25/tonne, the flaring option reaches the hurdle IRR, and the alternate flaring option hurdle is \$14.25/tonne. The CT and gas processing options require CO_2 offset values of \$26.50/tonne and \$27.00/tonne, respectively, to meet a 10.99% IRR.

* * * * *

<u>EXHIBIT H</u>

VERDEO VAM ANALYSIS

Ventilation Air Methane Oxidation Feasibility Study

Evaluation of Technical and Economic Project Viability at the West Elk Mine
September 2009

Prepared for Mountain Coal Company LLC for the West Elk Mine

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Table of Contents

I. Executive Summary

Verdeo Group, Inc. (Verdeo) was contracted by Mountain Coal Company, LLC ("Mountain Coal") to ascertain the economic and technical feasibility of a system that abates the ventilation air methane (VAM) that is emitted by the main ventilation system at Mountain Coal's West Elk Mine in Somerset, Colorado. Currently, the only technology capable of destroying the quantities and concentrations of methane present in coal mine central ventilation systems is thermal oxidation. Regenerative thermal oxidation is recognized as the most appropriate type of oxidation system for mine applications as demonstrated by installations in the U.S., U.K., China, and Australia, and is the primary technology considered for this feasibility study.

Verdeo visited the West Elk Mine on May 7, 2009 for a presentation and surface tour, which was hosted by the mine's senior management and engineers. The site visit enabled Verdeo to inspect potential installation locations and discuss with mine engineers a range of technical issues pertinent to the potential installation of an oxidation system. Mountain Coal provided data necessary to perform this analysis, including detailed information on the ongoing reconfiguration of the central ventilation system, topographical and surface information, and anticipated characteristics of ventilation air exhausted at Shaft #4 and Sylvester Gulch exhaust shaft. The historical and projected ventilation air exhaust data was provided by Mountain Coal to Verdeo. This analysis is based primarily on the ventilation exhaust characteristics that Mountain Coal anticipates following the completion of the ongoing ventilation system reconfiguration.

Thermal oxidation technology can abate methane concentrations over 0.2% without the use of supplemental fuel. Mountain Coal predicts that the VAM concentration at Shaft #4 will range between 0.15% and 0.31% upon completion of the ventilation system reconfiguration and transition to mining E Seam. Given the sensitivity of oxidizers to even short periods of low fuel concentration and the likelihood that VAM concentrations will be less than 0.2% under normal operating conditions, it is not technically feasible to develop a self-sustaining thermal oxidizer to destroy ventilation air methane at the West Elk Mine. The VAM concentration is too low to produce high-grade heat or electricity, thereby further diminishing the economic feasibility of a project.

Even if these technical obstacles could be overcome, it is not economically feasible for Mountain Coal to develop a ventilation air methane oxidation project at the West Elk Mine in the current and foreseeable market conditions. The only revenue generated by the oxidizer would be from the production of carbon offset credits that are sold into pre-compliance or voluntary carbon markets. This revenue would not sufficiently offset the high equipment and site preparation costs and high operating costs of an oxidizer system.

This VAM Feasibility Study presents an overview of oxidation technology, power generation with oxidizers, a comparison of oxidizer manufacturers, oxidizer operations, safety, and maintenance, and financing vehicles that would be possible if Mountain Coal developed an oxidizer project at the West Elk Mine.

II. Oxidizer Technology

Thermal oxidation is the process of applying heat to break a substance down to fundamental elements such as carbon dioxide and water. Methane, for example, oxidizes in atmosphere at 1,000°F. Thermal oxidation has been used for air pollution control for several decades in numerous industries, including chemical processing, petroleum and natural gas, and environmental remediation. Numerous types of thermal oxidizers are commercially available, including regenerative thermal oxidizers, catalytic thermal oxidizers, and direct fired thermal oxidizers.

Regenerative thermal oxidizers (RTO) utilize ceramic media beds to retain heat given off during the oxidation of target pollutants. Incoming airflow containing pollutants is drawn through the media beds with blower fans, where it reaches the temperature necessary for oxidation. Utilizing heat retained in the media bed significantly reduces the amount of supplemental heat (i.e., fuel) required to achieve oxidation of pollutants. In some cases, the amount of heat released during oxidation and stored in the media bed is sufficient to fully oxidize the incoming airflow without supplemental heat. This can be achieved with methane concentrations as low as 0.2%. Due to the high cost of a continuous supply of supplemental heat, a self-sustaining RTO is the most practical design for VAM applications. Note that "self-sustaining" refers to heat energy; RTOs still require electricity to drive blower fans, valves, and control equipment.

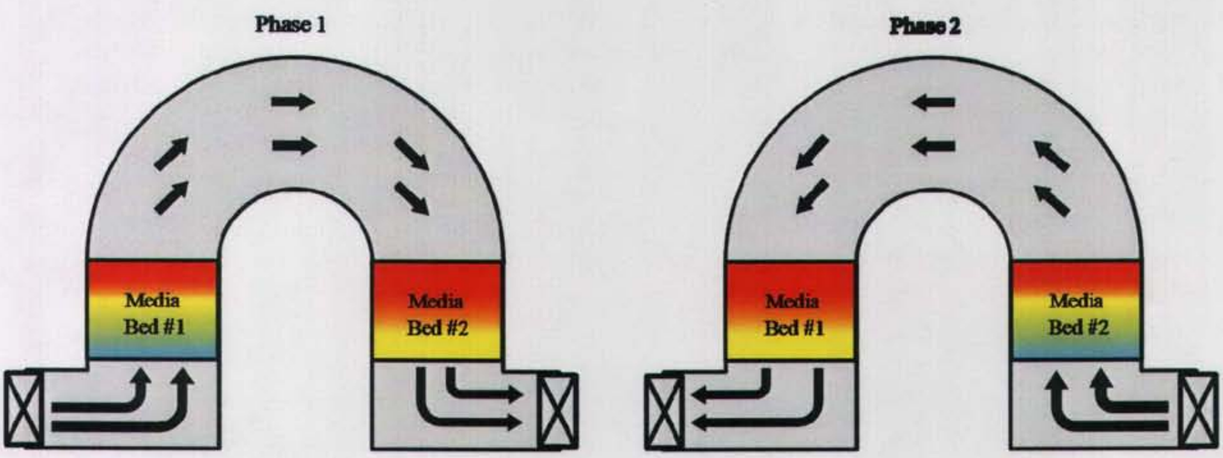
Catalytic thermal oxidizers use ceramic media impregnated with metallic compounds to catalyze the oxidation process of the target pollutant. The catalyst typically reduces the oxidation temperature of the pollutant, which allows the use of thinner ceramic beds. Thinner ceramic beds require smaller blower fans to move air through the system and can be maintained with lower electric loads. Catalytic oxidizers are most appropriate where the higher cost of catalytic media is recovered by savings from reduced electric loads.

Direct fired thermal oxidizers use a process that has not fundamentally changed since oxidizers were originally designed with steel boxes containing conventional burners that directly heat pollutants to oxidation temperatures. Original designs were very inefficient as they required large, continuous sources of supplemental heat. Modern direct fired thermal oxidizers often incorporate heat recovery, heat retention, or waste heat boiler systems. Many pollutants require supplemental heat to be fully oxidized in this type of oxidizer. Direct fired thermal oxidizers are commonly referred to as enclosed flares, incinerators, or afterburners, and would be appropriate for high methane concentrations found in mine drainage well gas.

Note that all thermal oxidizers require a heat source to initially heat the ceramic media bed to the desired oxidation temperature. This is achieved by heating the bed to the target oxidation temperature using natural gas, propane, diesel, or electricity.

Most modern types of oxidation systems (including RTO and catalytic) have two ceramic media beds and are referred to as "two-can" oxidizers. One bed is used to heat the incoming air to the point of oxidation, and the other bed is used to retain heat before the airflow is exhausted. When the inlet heating bed has cooled and the heat retention bed is sufficiently hot, the airflow is reversed. The heating bed (previously the heat retention bed) heats incoming air as it enters the oxidizer. The continued oxidation process subsequently heats the heat retention bed (previously the heating bed) until the flow reversal is eventually repeated (see diagram below).

Regenerative Thermal Oxidation



In Phase 1, airflow passing left to right heats to oxidation temperature as it flows through Media Bed #1. Heat from oxidation is retained in Media Bed #2. The reversal of airflow initiates Phase 2 when Media Bed #2 has been sufficiently heated (and Media Bed #1 has been cooled by incoming airflow). This process is repeated to maintain continuous oxidation of the airflow.

Airflow is reversed with a set of large valves that control the direction of flow through the oxidizer. Different manufacturers utilize various types of valves to control the airflow, including poppet, butterfly, or rotary. While the airflow is reversing, the valves allow air containing the pollutant to escape without passing through a media bed. The escaping air, typically less than 5% of the total hourly flow, is the primary cause of reduced pollutant destruction, which is measured by Destruction Rate Efficiency (DRE). Some oxidizers incorporate a third ceramic media bed to eliminate this leakage and increase the DRE of the system. These beds are known as "three-can" oxidizers. In most mine methane applications, the additional cost of the third media bed cannot be recovered by the value of the additional carbon offset credits that the three-can system generates.

Fans, which are the other (besides valves) major moving parts in RTOs, are required to draw air from the source (e.g., mine vent exhaust) into the oxidizer and through the ceramic media beds. Powering blower fans, which can be rated up to 500 kW, is often the largest operating expense of oxidizers. These fans actively pull airflow into the oxidizer; the oxidizer does not rely on pressure of the VAM airflow to intake air. Therefore, a properly designed VAM oxidizer system does not add resistance or increase power requirements of the mine's central ventilation fan. Airflow with lower concentrations of methane requires thicker media beds through which the airflow is blown. This necessitates larger oxidizer blower fans to overcome the greater pressure loss created by the thicker beds. The increased cost of the media bed along with greater operating costs of the larger fans typically limit economic feasibility to projects with methane concentrations greater than 0.4%.

Economies of scale for oxidizers peak at flow rates of about 100,000 cfm. Furthermore, it is difficult to achieve consistent airflow across media beds at rates above 100,000 cfm. Uneven flow results in cold spots that can significantly degrade the DRE. Therefore, where very large quantities of air are oxidized (e.g., mine ventilation systems), oxidation systems are designed with parallel units that each process 100,000 cfm or less. A typical physical space requirement for a 100,000 cfm system is a level surface approximately 70' x 50'.

III. Power Generation from Thermal Oxidation

Numerous mines and oxidizer manufacturers have explored the potential to generate electricity from heat produced by thermal oxidizers. Despite the large volumes of high-temperature gas created by oxidizers, few oxidizers produce sufficient heat to generate electricity. One notable system that does generate electricity, however, is installed at the Illawarra Mine in Australia (owned by BHP Billiton). This system oxidizes VAM to generate 6MW of electricity.

As implied by the negative outlook for a VAM oxidation system at the West Elk Mine, the prospects for a VAM oxidation power generation system are essentially non-existent at this time. However, Verdeo has reviewed situations where VAM concentrations and electricity prices warranted the exploration of a VAM power generation system. We therefore provide a brief overview of generating power from oxidizers.

Most RTOs do not produce sufficient waste heat to generate electricity from exhaust gas flow. It is, however, simple and inexpensive to produce low-grade heat from RTO exhaust flows. Heat generation systems can be as basic as shell and tube heat exchangers that are located directly in the exhaust vent and cost only a few thousand dollars.

In certain situations it is possible to generate electricity with RTOs. Electricity generation systems collect heat with a series of shell and tube heat exchangers that are located in the oxidation chamber. Steam is superheated in the exchangers and passed through a multistage condensing turbine that drives a generator. The exhaust steam is condensed at the outlet of the turbine and processed through a deaerator and into the boiler section of the feedwater. Such generators in this type of application typically have efficiency ratings of 20-28%. The parasitic load of additional equipment necessary to generate electricity amounts to approximately 15% of the total energy generated (i.e., a 5MW power plant requires a ~6MW generator).

In ideal situations, power generation becomes feasible at or above capacities of 5MW. Such a system would generally cost between $10-15M. Systems operating in warm climates require water condensers or evaporative cooling towers that require upwards of 20,000 gallons per hour. Additionally, the electrical infrastructure for this type of system is considerably larger than that of traditional oxidizers.

IV. Oxidizer Manufacturers

There are over thirty oxidizer manufacturers worldwide. Most are located in the U.S. and Europe; a few are located in Japan and Australia. At least three manufacturers have produced systems specifically for the coal mining industry (MEGTEC, Biothermica, and Shengdong). A comparative analysis of select oxidizer manufacturers is in Appendix A, and is also provided in the attached file, "RTO Manufacturer Comparison".

MEGTEC Systems Inc. (www.megtec.com) has targeted coal mines for many years under the "VOCSIDIZER" trademark. In 1994, MEGTEC was the first company to install a system on a coal mine (Thoresby Mine in the U.K., owned by UK Coal). Since then, the system has evolved into a robust and reliable design. MEGTEC has installed two VOCSIDIZER™ units on operating mines in Australia, and one unit that was installed as a pilot project on CONSOL Energy's Windsor Mine (a closed mine in West Liberty, WV). The VOCSIDIZER™ uses two ceramic media beds connected by a central combustion zone. The system places electrical heaters in the media bed to heat the system for start-up. The MEGTEC design is particularly well-suited for heat recovery purposes where high VAM concentrations are available. MEGTEC also offers two-can RTOs of more traditional design, which are better suited for simple VAM oxidation projects.

MEGTEC VOCSIDIZER system installed at CONSOL Energy's Windsor (closed) mine.

Biothermica Technologies, Inc. (www.biothermica.com) has also been working with coal mines for several years and successfully commissioned a system on an operating mine at the beginning of 2009 (at Jim Walter Resources' Mine No. 4 near Brookwood, AL). This technology uses a straightforward and well-tested two-can RTO design with certain innovative improvements such as a "hot side bypass" that safely and effectively accommodates surges in methane concentrations. Their basic design is highly reliable and well-suited for simple VAM oxidation. It is possible to generate low-grade heat with a standard Biothermica system, but the design does not readily accommodate modifications for electricity generation. Biothermica currently offers only a build-own-operate option for VAM applications. In this arrangement, Biothermica finances the majority (or all) of the system and recovers its costs primarily by retaining ownership of the carbon offset credits generated by the system. Biothermica typically compensates the mine with a negotiated share of the project economics in return for the mine's contributions to the project (e.g., rights to the VAM, operational support).

Biothermica VAMOX^{TM} system installed at Jim Walter Resource's Mine No.4.

Oxidizers made by most manufacturers do not require significant design modifications to process VAM. Through a Request for Information process, we assessed four additional budgetary proposals from various leading U.S. oxidizer manufacturers with little or no experience in the mining industry to evaluate for potential application at the West Elk Mine. Summaries of these systems are below.

Met-Pro Systems (www.met-prosystems.com), a unit of the publicly traded Met-Pro Corporation, has designed and built systems to manage volatile organic compounds for over 40 years. Its RTO system uses a two-can design that employs various methods of heat rejection to maintain optimum performance. For example, if methane concentration increases beyond the design range, an air damper allows fresh air into the RTO to cool the system. If methane concentrations reach very high levels, a "hot side bypass" damper opens to force hot gases directly from the combustion chamber to the exhaust stack. Met-Pro designs and fabricates their systems specifically for each application and offers one of the most competitive prices in the industry.

Durr System, Inc. (www.durr.com) is a $2B global company with a strong and growing presence in the U.S. Durr is currently looking at several opportunities in the mining industry and may deploy a unit on an operating mine within the next year. The Durr RTO system uses a unique rotary valve that reduces the amount of airflow that escapes during valve actuation and allows DREs of up to 99%. The system requires blower fans that are larger than those of most RTO systems of the equivalent capacity. Durr RTOs are pre-engineered with sizes up to 60,000 cfm, which reduces manufacturing and installation times and competitive pricing.

Cycle-Therm, Inc. (www.cycletherm.com) offers a basic two-can RTO at a moderate price. The system uses unique ceramic media that requires a relatively small blower fan. The Cycletherm unit may be susceptible to dust erosion due to the type of media used, which tends to be sensitive to high dust applications. Cycletherm units are manufactured in Pennsylvania.

Anguil Environmental Systems, Inc. (www.anguil.com) manufacturers multiple oxidizer systems for various industries and has over 1,600 systems operating worldwide. Their RTO offers a well-designed system that incorporates a "hot side bypass" similar to that of the Biothermica system. Their electrical fan power requirements are high due to the large ceramic media bed used in their systems. Despite the technically sound design, the high cost of the Anguil system makes it less appropriate for most VAM applications.

V. Regenerative Thermal Oxidizers: Safety, Operations, and Maintenance

Coal mines ventilate methane that is released through coal production activities to the atmosphere using various drainage and ventilation systems. The continuous use of these ventilation systems is imperative for the safe operations of the mine. The predictable and stable characteristics of VAM exhausted by central ventilation systems are often suitable for the application of a thermal oxidizer that destroys the methane as it exits the ventilation shaft.

Oxidizers utilize mature technology and have been operated for several decades in the U.S. and Europe. In fact, the first oxidizer deployed on a coal mine ventilation system was commissioned over 15 years ago. Although the fundamental technology has not significantly changed, understanding and control of the oxidation process has notably improved over the past decade.

The installation of an oxidizer unit on any of the vent shafts at the West Elk Mine must be safe. As with gob well extraction pumps and ventilation intake heaters, oxidizers contain an ignition source and must not be subjected to flammable concentrations of methane (5% to 15%). The greatest safety risk would be posed by an exceptional gas outburst or catastrophic event that would produce methane concentrations in excess of 5% at the mine ventilation outlet. Based on discussions with the ventilation engineers and senior management at the West Elk Mine, it is unlikely that such an event would produce volumes and concentrations of methane in underground areas of the mine to generate more than 5% VAM concentration at the ventilation shaft outlet. However, some scenarios, such as a seal failure in a closed portion of the mine, could produce methane excursions that are difficult to model.

Given the catastrophic consequence of explosive hazards, oxidizer safety systems must be designed to prevent the possibility of a flammable gas-air mix from reaching an ignition source. This is achieved with redundant systems and conservative safety margins throughout the oxidizer system. An example of a safety system that was approved by MSHA is a fast-response methane analyzer installed on the Biothermica RTO operating at Jim Walter Resources' Mine No. 4 in Brookwood, Alabama. If the methane concentration in the airflow exiting the ventilation shaft reaches a certain threshold (2%), a damper is automatically released to immediately block airflow to the RTO. VAM airflow must travel through a length (approximately 100 feet, minimum length as required by MSHA) of duct between the ventilation exhaust shaft and RTO intake, thereby allowing sufficient time between the detection of a high methane concentration and the damper actuation that prevents VAM from entering the RTO. Additionally, the RTO intake is physically and electrically separated from the exhaust shaft, so that it is not possible for a sudden stoppage of airflow to the RTO (or RTO system failure) to have any impact on the ventilation system.

During the development of a VAM oxidation project, a comprehensive, site-specific risk assessment and Hazard Operational Analysis (HAZOP) would be performed to comprehensively demonstrate that the oxidizer system cannot affect the safety of the mine. The assessment would require a systematic examination of the detailed operations of the mine, the reaction time of methane sensors, and any control or mechanical interface with the mine. Long-term ventilation system plans should be considered in this assessment as oxidizers are designed to operate for over 20 years.

Oxidizers are typically highly-automated and have low operating and maintenance requirements. The staffing of an oxidation system is typically performed by one or two surface personnel that perform short daily inspections and complete routine maintenance procedures. For budgeting purposes, it is appropriate to assign 1/3 of a full time equivalent engineer to operate the system.

Scheduled maintenance is generally limited to lubrication of moving parts, replacing valve seals, bearings, and fan belts, and cleaning equipment, all of which can be performed by most mine surface crews. Long-term maintenance, including annual internal inspections and maintenance of ceramic media would be performed by the oxidizer supplier under a maintenance contract.

The most common maintenance risk on VAM applications is contamination of ceramic media beds. The media can require more frequent maintenance (i.e., cleaning) if air flows contain significant amounts of large inorganic dust particles. The West Elk Mine Shaft #4 exhaust airflow will contain dust particulates, though based on conversations with mine engineers, we anticipated that the small size of the dust would likely pass through the unit without causing blockage. If an oxidizer project is pursued, the actual characteristics of the exhaust flow should be investigated early in the design process.

VI. Feasibility of Thermal Oxidation at the West Elk Mine

Based on the design and anticipated performance of the reconfigured mine ventilation system, it is not technically or economically feasible in the current or foreseeable future to develop an oxidation system at the West Elk Mine. However, there are no safety or operational concerns that would categorically prohibit the installation and operation of a VAM oxidation project at the mine, given appropriate safeguards.

From a technical perspective, Mountain Coal anticipates that the reconfigured ventilation system will produce VAM concentrations at Shaft #4 between 0.15% and 0.31%. The risk posed by this low range, which includes concentrations below the minimum operating limit of 0.2% for self-sustaining RTOs, is compounded by the inherent uncertainty of models used to predict performance of ventilation systems. Furthermore, short drops in VAM concentrations can cause oxidizers to fail quickly, requiring manual labor to adjust or restart the system.

Due to the configuration of oxidizer airflow intake systems, it is unlikely that an oxidizer would be able to process more than 50% of the 800,000 or greater cfm projected to flow from the exhaust shaft. The limits of oxidation are further constrained by the surface area available at the Shaft #4 pad, which could likely accommodate an oxidizer system with a total capacity of 150,000-250,000 cfm. The secondary exhaust at Sylvester Gulch has an expected methane concentration of 0.05% and is therefore incapable of self-sustaining oxidation with the technologies available today.

Operational and safety risks, as described above, would be low for the most likely configuration of an RTO installed at Shaft #4. It would be necessary to access the system on a daily basis throughout the year (without heavy equipment during normal operations), which would require maintenance of the mountainside access road through the winter months.

As stated above, the economics of an RTO at Shaft #4 are bleak. The typically high equipment and site preparation costs of RTOs would be exacerbated by the remote, mountainous location of the ventilation shaft. For example, installing power lines to provide electricity to Shaft #4 would present a significant cost risk to a project. As electricity generation from the RTO system would not be possible at Shaft #4, the generation of carbon offset credits would be the only source of project revenue created by an RTO system. Even in aggressive market scenarios, it is highly unlikely that the cost of the RTO would be recovered through carbon offset credit revenues in less than 10 years. We therefore conclude that it is not economically feasible to develop a VAM oxidation project in current and projected market conditions using the best available commercial technology to oxidize methane in the ventilation airflow.

In accordance with the statement of work, Verdeo is providing a basic financial analysis of oxidation systems. The analysis uses Microsoft Excel to project the 10-year economic performance of an RTO system based on multiple input assumptions. The model was designed for Mountain Coal to evaluate revenues in different carbon market scenarios. A screenshot of the financial analysis is in Appendix A. The model is also provided in the attached file, "Verdeo Mountain Coal VAM Feasibility Study, June 25, 2009.xlsx". As demonstrated by the financial model, the two most significant factors that impact the economic feasibility of an RTO system are the cost of the RTO system and the VAM concentration of the ventilation exhaust. The model uses a default cost for the RTO system that is based on budgetary cost estimates provide by five RTO manufacturers specifically for conditions at Shaft #4[1]. The cost factor is expressed as a cost per cubic feet of airflow processed by the RTO ($/cfm), a metric commonly used

[1] The requests for budgetary cost estimates were sanitized and did not reference Mountain Coal or the West Elk Mine.

to compare oxidizer systems. The default VAM concentration is based on the value projected for Shaft #4. Both cost and VAM concentration can be modified in the model.

Appendix A: Verdeo Mountain Coal VAM Feasibility Study, June 25, 2009
RTO Manufacturer Comparison

Regenerative Thermal Oxidizer Manufacturer Comparison							
RTO Manufacturer:	Biothermica	MEGTEC	Cycletherm	Met-Pro	Anguil	Durr	Average
RTO Economic Comparison							
Subtotal RTO system cost ($)	n/a	2,100,000	1,700,000	1,230,000	1,950,000	1,550,000	1,706,000
Development costs + contingency @ 20% of total system cost[1]	n/a	420,000	340,000	246,000	390,000	310,000	341,200
Total RTO cost for 100,000 cfm system ($)	n/a	2,520,000	2,040,000	1,476,000	2,340,000	1,860,000	2,047,200
Unitized RTO cost ($/cfm)	n/a	25.2	20.4	14.8	23.4	18.6	20.5
Maintenance and supplies @ 3% CapEx/a ($/a)	n/a	75,600	61,200	44,280	70,200	55,800	61,416
Electric parasitic load (kW)	350	350	300	390	480	440	385
RTO Design Comparison							
Number of oxidizer units needed to process 100,00 cfm.	1	2	2	2	2	2	2
Manufacturing lead time (weeks)	32	24	16	24	20	24	23
Thermal efficiency (% heat recovery)	96%	95%	94%	95%	95%	95%	95%
RTO design life (years)	15-20	7-20	20-30	10-15	20	15-20	15-20
Start-up profile (fuel type, duration, energy requirement)	propane, gas, 8 hours, 50 MMBtu	electricity, 24 hours, 11 MWh	diesel, 1 hour, 7 MMBtu	diesel 1 hour 9 MMBtu	diesel, gas, propane, 2 hours, 18 MMBtu	diesel, gas, propane, 8 hours, 16 MMBtu	10 MMBtu is about (75 gallons of diesel).
RTO footprint and weight	90' x 40', 200,000 lbs	100' x 70', 680,000 lbs	43' x 29', -	38' x 34', 310,000 lbs	60' x 80', 500,000 lbs	84' x 50', -	70' x 50 ', 420,000 lbs
Scope of standard manufacturer services	equipment, install, commission	equipment, install, commission	equipment, install commission for fee	equipment, install for fee, commission for fee	equipment, install, commission	equipment, install for fee, commission for fee	-

Footnotes:

1. Includes peripheral equipment such as site preparation, electrical interconnection, control buildings, lighting, etc., and other development costs such as early-stage engineering and permitting.

Appendix A: Mountain Coal VAM Feasibility Study, June 25, 2009
RTO Financial Analysis

Ventilation Air Methane Thermal Oxidation Simplified Financial Analysis

This financial analysis provides a 10-year projection of the economic performance of a ventilation air methane (VAM) oxidation system that generates economic value exclusively from the generation of carbon offset credits.

Note that all assumption cells that can be changed use blue text. Do not change cells with black text.

The assumptions cells that may be changed represent the key drivers of project performance. Note that values of carbon offset credits must be adjusted for each individual year.

The economic performance of the project (NPV and IRR) is in the yellow highlighted cells.

Economic Pro Forma (stand-alone project, cash-on-cash)										
Year	1	2	3	4	5	6	7	8	9	10
Ventilation shaft airflow rate (acfm)[1]	100,000									
Elevation adjustment[2]	-20.0%									
Vent shaft flow CH4 concentration, by volume[3]	0.25%	<<< ensure percentage is accurately entered (i.e., 0.0025 for .25%)								
Carbon offset credit value ($/tCO2e)[4]	5.00	6.00	7.00	8.00	9.00	10.00	12.50	13.00	13.50	14.00
Net GHG emission reduction (tCO2e)	30,555	30,555	30,555	30,555	30,555	30,555	30,555	30,555	30,555	30,555
Revenue, carbon offset credit ($)	152,775	183,330	213,885	244,440	274,995	305,550	381,937	397,214	412,492	427,769
Unitized RTO cost ($/cfm)[5]	20.50									
Total system cost, 100,000 cfm system ($)[6]	(2,050,000)									
OpEx, staff ($)[7]	(50,000)	(51,750)	(53,561)	(55,436)	(57,376)	(59,384)	(61,463)	(63,614)	(65,840)	(68,145)
Maintenance and supplies ($)[8]	(51,230)	(53,023)	(54,878)	(56,799)	(58,787)	(60,845)	(62,974)	(65,178)	(67,459)	(69,821)
Energy cost ($/kWh)[9]	0.07									
Energy costs ($)	(220,752)	(228,478)	(236,475)	(244,752)	(253,318)	(262,184)	(271,361)	(280,858)	(290,688)	(300,862)
Expenses ($)	(2,371,981)	(333,251)	(344,915)	(356,987)	(369,481)	(382,413)	(395,797)	(409,650)	(423,988)	(438,828)
Simple cash flow, no tax, no debt, immediate cash flow recognition ($)	(2,219,207)	(149,921)	(131,030)	(112,547)	(94,487)	(76,863)	(13,860)	(12,436)	(11,496)	(11,058)
NPV rate[10]	10.99%									
Project NPV ($)	(2,408,857)									
Project IRR	#NUM!									

Footnotes:

1. This represents the VAM airflow processed by the oxidizer. Default value is 100,000 cfm. Physical space of Shaft #4 could likely accommodate a system rated at 150,000-250,000 cfm.
2. The default value (-20%) represents an adjustment for a system located at 6,000' asl.
3. The default value (0.25%) represents the most likely VAM concentration anticipated at Shaft #4. The expected range of VAM concentration is 0.15% - 0.31%.
4. Dollars per metric tons of greenhouse gas (CO2 equivalent). The default values represent most likely value projections based on current market and regulatory environment.
5. Unitized cost is a metric frequently used to compare oxidation systems. The default value ($20.5/cfm) is based on budgetary proposals described on the RTO Manufacturer Comparison worksheet.
6. Calculated by multiplying the unitized system cost by the VAM airflow rate. This value includes engineering, development, permitting, procurement, installation, commissioning.
7. The default value ($50,000) is based on 1/3 full-time mine engineer and is conservatively based on estimates of multiple RTO manufacturers.
8. The default value is based on an annual cost equivalent to 3% of RTO system cost (i.e., not total system cost). This value will vary among RTO manufacturers.
9. The default value ($0.07/kWh) is based on rates paid by the West Elk Mine.
10. The interest rate (10.99%) is an assumption that should be updated for each specific application based on internal hurdle rate requirements.

EXHIBIT I

VERDEO CARBON MARKET ANALYSIS

Verdeo group Vg

Carbon Assessment Report

September 2009

Prepared for Mountain Coal Company LLC for the West Elk Mine

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Table of Contents

I. Executive Summary

Federal policy to regulate greenhouse gas (GHG) emissions is developing. As currently proposed by Congress, this would take the form of a cap-and-trade program. If cap-and-trade is not enacted, the EPA may attempt to regulate U.S. GHG under the Clean Air Act. While such policy may not be welcomed by coal mining companies, opportunities are emerging for owners of coal mines to benefit financially from the implementation of these policies. In fact, it is possible that coal mines will not be regulated for methane emitted during the mining process, and that projects developed to reduce methane emissions from mine ventilation and degasification systems will be able to generate compliance-grade carbon offset credits. In response to these emerging developments, Mountain Coal Company LLC (Mountain Coal) retained Verdeo Group, Inc. (Verdeo) to develop a Carbon Assessment Report that provides a detailed overview of the U.S. carbon market and emerging GHG policies to document how the coal mining industry, and particularly gassy underground mines, may be impacted by these impending developments. This report also includes an overview of the current U.S. carbon offset project certification programs, a high-level overview of the coal mine methane (CMM) carbon offset project types, a description of processes required to certify high-quality projects, and an analysis of current carbon offset prices and future price projections.

Verdeo's key findings from this Carbon Assessment Report are:

- Emerging legislation suggests that cap-and-trade will be the most likely framework of any federal program to reduce GHG emissions. A cap-and-trade program is also expected to include a carbon offset program in order to reduce the costs of compliance for capped facilities.

- Current legislation making its way through Congress suggests that coal mines may not be regulated for their methane emissions under a cap-and-trade program, and may have the opportunity to generate carbon offset credits for emission reductions implemented under a GHG cap-and-trade program.

- As federal policy emerges, state and regional cap-and-trade programs continue to develop mandatory cap-and-trade programs. Key developments in the west, including the State of California's program and the regional Western Climate Initiative, may recognize CMM offset projects.

- In anticipation of U.S. cap-and-trade programs, a "pre-compliance" market has emerged that provides potential frameworks for developers of CMM offset projects to certify and monetize GHG emission reduction assets.

- Successful carbon project development requires careful planning and execution to ensure the value of emission reduction assets is maximized. This is critical to ensure that projects implemented in the near-term are positioned to maintain value as the market transitions to a compliance cap-and-trade program.

II. Overview of Cap-and-Trade and Carbon Offsets

Cap-and-trade has emerged as the most likely structure under which GHG emissions in the U.S. economy will be addressed, if federal GHG legislation is enacted. Understanding how cap-and-trade programs and carbon offset credits work is critical to understanding how coal mines may be able to participate in these emerging frameworks.

Cap-and-Trade

Cap-and-trade is often discussed as an efficient and cost-effective system to reduce GHG emissions. The objective of an emissions cap-and-trade program is to minimize costs of compliance by providing regulated facilities with flexibility in how they meet their reduction target. The idea is that companies that can reduce emissions at lower cost than others have an incentive to do so, and can sell these reductions to other entities regulated under the cap. Cap-and-trade was first enacted into law in the emissions trading scheme developed as part of the Acid Rain Program created under Title IV of the 1990 Clean Air Act to address emissions of NO_X and SO_X. The success of this program led U.S. climate negotiators to propose emissions trading as a way to manage GHG emissions as part of the Kyoto Protocol, which was adopted in 1997 but never ratified by the U.S. Senate.

Determining the sources of emissions that will be covered under the cap is fundamental to the design of an effective cap-and-trade program. Since measuring and reporting of emissions entails significant costs, large stationary sources that emit GHG emissions such as electric power plants and large industrial facilities are typically targeted under a cap. For example, coal mining companies may not be capped directly, but electric generators that burn coal or natural gas could be capped and would have to submit allowances (i.e., pollution permits) to the government on a regular basis. The cost of electricity and other products in the U.S. will incorporate the additional costs of these allowances, an intended effect designed to reduce the carbon intensity of the U.S. economy.

Numerous other sectors and sources of emissions in the economy typically remain uncapped under GHG cap-and-trade programs, either because the sector's aggregate emissions are too small or the nature of the emissions makes them difficult or costly to cap. Under a well-designed cap-and-trade program, sources not affected by a cap will have abatement incentives through a compliance-based offset program. While emerging cap-and-trade programs in the U.S. have all defined or proposed slightly different sets of eligible project types or sectors under an offset program, all, to varying degrees, have proposed to recognize projects that capture and combust fugitive methane emissions from such sources as coal mines, landfills, and livestock farms.

Carbon Offsets

A carbon offset credit (or "offset") is an instrument reflecting the reduction, avoidance, or sequestration of a quantity of gas with a global warming potential equivalent to that of one metric ton of carbon dioxide that is achieved in an uncapped sector or facility (hence, the term "carbon dioxide equivalent", or CO_2e). Coal mines may be eligible to generate offsets in a future cap-and-trade program, for several reasons. Since the electricity sector is the largest source of GHG emissions in the U.S. and will very likely be capped, extending limitations to coal mines would essentially "double tax" utilities and the coal industry. By allowing coal mines to generate offsets instead, companies have a positive incentive to develop GHG abatement or utilization projects. In addition, coal mines must optimally manage methane for the safety of its workers; new policies must not interfere with mines' ability to safely manage its methane.

III. U.S. Climate Change Policy

Current activity at the state, regional, and federal levels is setting precedents and driving the formation of the forthcoming U.S. carbon market, including how coal mines and their associated methane emissions will be impacted in the long-term. Below, we provide a detailed overview of the various state, regional, and federal GHG initiatives in development.

State and Regional Policy

States and regions have historically been the earliest movers to introduce and pass climate change-focused policy initiatives, including renewable energy production mandates, GHG reduction goals, and mandatory cap-and-trade programs. These efforts paved the way for action at the federal level and significantly influenced developments in the U.S. voluntary and pre-compliance carbon markets. While a federal program has a high probability of eventually preempting, at least in part, GHG programs already established at the state and regional levels, the Federal government will likely recognize reductions made under these programs, including any offsets registered and generated before a federal program is formally implemented on an "early action" basis.

This chart contains a brief summary of the leading state and regional cap-and-trade programs in effect or under development in the U.S., including prospects for recognizing CMM offset projects:

	The Regional Greenhouse Gas Initiative (RGGI)	State of California	Western Climate Initiative (WCI)	Midwestern Greenhouse Gas Reduction Accord
Program Scope	Caps GHG emissions from electricity generating facilities with capacity of 25 MW or greater	Will cap approximately 85% of CA's emissions; program rules are in development	Will cap approximately 90% of regional GHG emissions; program rules are in development	Accord is under development, but participating states have committed to implement a regional cap-and-trade program
States	Ten Northeast and Mid-Atlantic states[1]	California, but expected to link with the WCI	Seven U.S. states[2] and four Canadian provinces[3]	Nine Midwestern states[4] and two Canadian provinces[5]
Program Start Date	January 2009	2012	2012	2012
Includes Offset Program?	Yes – However no protocol for coal mine methane projects	Yes – Likely to include offsets from coal mine methane projects	Yes – Likely to include offsets from coal mine methane projects	Yes – Offset types are not yet defined, but Accord recommends linking with other programs such as RGGI and WCI

State and regional activity on GHG emissions is relevant to the coal mining sector for multiple reasons. First, the rules of these programs are impacting the design of a future federal program. Second, these programs create real demand for carbon offset credits generated by coal mines, regardless of federal actions. Third, there is an expectation that recognized offsets will be accepted under a federal program, which creates demand for offsets generated under these state and regional programs. While RGGI recognizes only a sub-set of eligible offset project types (and not CMM), there is a greater chance that CMM offsets will be recognized in California and the WCI. More detail on the likelihood of CMM projects being accepted under the California and WCI programs is outlined in Section VI.

Colorado State Policy

The state of Colorado is taking a number of steps to transition to a lower carbon economy. Colorado, along with five other U.S. states and a handful of Mexican states and Canadian provinces, is an observer to the WCI. While Colorado's observer status does not carry regulatory authority[6], it does signal an interest of the state government in climate change issues. In 2007, Governor Ritter released the Colorado Climate Action Plan, which set a goal for the state to reduce GHG emissions by 20 percent by 2020. The state also set a precedent for similar action when it enacted an aggressive renewable portfolio standard that calls for 20% of electricity purchased by electric utilities to be from renewable sources by 2020.

Colorado also encourages the voluntary purchase of carbon offsets by individuals and corporations. The Colorado Carbon Fund (CCF), a voluntary carbon offset program developed by the Governor's Energy Office, purchases carbon offsets from projects developed in Colorado. The CCF is primarily interested in purchasing small volumes of carbon offset credits (less than 10,000 tons per year) and prefers to be the sole purchaser of offsets generated from a project. As a result, the CCF is not a target purchaser of offsets generated from CMM projects, which

[1] The states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont are signatory states to the RGGI agreement.

[2] Members: Arizona, California, New Mexico, Oregon, Washington, Utah and Montana. Observers: Alaska, Colorado, Idaho, Kansas, Nevada, and Wyoming.

[3] Members: British Columbia, Manitoba, Ontario, and Quebec. Observers: Saskatchewan. Mexico observers: Border states of Baja California, Chihuahua, Coahuila, Nuevo Leon, Sonora, and Tamaulipas.

[4] Members: Iowa, Illinois, Kansas, Michigan, Minnesota, and Wisconsin. Observers: Indiana and Ohio.

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generate significantly larger volumes of credits annually. More importantly, the CCF is willing to work in conjunction with the Governor's Energy Office to connect sellers of large-volume offsets with large pre-compliance buyers in the state that are seeking offset credits in ahead of federal GHG regulations.

Federal Policy

While state and regional action on GHG emissions continues to progress, implementation of a federal climate change program may have the greatest impact on coal mines. The most notable Congressional activity of this year to date has been the passage of the *American Clean Energy and Security Act of 2009* (*ACESA*), which was introduced by Representatives Waxman (D-CA) and Markey (D-MA). This bill, H.R. 2454, proposes to establish a federal cap-and-trade program to reduce GHG emissions. It includes a domestic offset program to help reduce costs of compliance, and included provisions to provide some "early action" recognition for emission reductions generated in advance of a federal program. Overall, however, the bill largely left the EPA with the discretion to design the structure of the offset program.

With the passage of the *ACESA* bill in the House, the Senate has subsequently announced that it is working to draft its own version of a cap-and-trade bill. This process is being managed by Senator Boxer (D-CA), who is the Chair of the Environment and Public Works Committee. While initial indications suggested that Senator Boxer would release a draft bill by September 8, the Senator has since announced that the date of release will be pushed back to an as yet undetermined date at the end of September. It is too early to speculate on the content of this forthcoming bill or what its prospects for passage may be in the Senate.

As the Senate continues to develop GHG legislation, the EPA has started a rulemaking process to regulate certain sources of GHG emissions under the Clean Air Act. This rulemaking comes in response to the EPA's "endangerment finding" in April 2009, which, prompted by the 2007 Supreme Court decision in *Massachusetts v. EPA*, found that GHG emissions endanger public health and welfare. However, it is highly uncertain to what extent GHG regulation will actually be implemented by the EPA, as the rulemaking process is expected to take several years and could be pre-empted by Congressional action. In one of its first rules, the EPA has already proposed to exempt smaller sources of emissions from being subject to any new regulation under the Clean Air Act, and instead keep the regulation focused on larger sources. We anticipate that the most probable outcome of the EPA's endangerment finding and its subsequent rulemaking is that it may eventually prompt Congress to pass legislation – if not this year, then in 2010 or 2011.

IV. Impact of GHG Policy on Coal Mines

Although GHG legislation will likely present challenges for coal mines and related businesses, we see evidence to suggest there may be positive outcomes and opportunities for coal mines under a federal cap-and-trade program. Most members of Congress recognize the critical role that coal plays in providing the U.S. with the majority of its low-cost electricity, and want a program that will mitigate any negative effects on the competitiveness or viability of U.S. companies. Incentives for carbon capture and sequestration are likely to have a prominent role in legislation, and will be designed to facilitate development and deployment of "capture-ready" coal-fired power plants.

Notably, the *ACESA*, as well as earlier proposed versions of federal GHG legislation such as the Lieberman-Warner Climate Security Act in the Senate and the Dingell-Boucher Discussion Draft in the House, all included provisions to establish a federal offset program. With the exception of the *ACESA*, these bills specifically included a list of project types on a "positive list" that should be eligible to generate offsets under a federal program. For example, the Climate Security Act recognized "methane capture and combustion at nonagricultural facilities", and Senator Debbie Stabenow (D-MI) filed a supplementary amendment to the Act to amend much of the bill's original language on offsets to include "methane capture or combustion at…coal mines" on a positive list of eligible offset project types. The Dingell-Boucher Discussion Draft also included "methane collection and combustion from projects at active underground coal mines" on a positive list, and referenced "methane reduction from reclamation of abandoned surface mines"[7] on a list of project types that EPA should consider adding to the positive list.

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While there has been significant momentum to allow emission reduction projects at coal mines to generate offsets under a cap-and-trade system, it should be noted that there is also a growing push by some environmental groups to have the EPA regulate various sources of methane under the Clean Air Act. For example, the *ACESA* included a provision to require the EPA to regulate emissions from landfills and natural gas systems – a provision that would disqualify many facilities from generating offset credits. This provision did not include emissions from coal mines as a source for which such standards would be applied. Therefore, while coal mine emissions appear to be exempt from the prospect of regulation under the *ACESA*, coal mines should closely monitor the development of legislation as it moves through Congress to ensure that this threat does not emerge in subsequent deliberations.

While activity at all levels of government suggest that it is most likely for a cap-and-trade program to be implemented at the federal level, and that it is probable that coal mines will not be capped or regulated under other standards such as the Clean Air Act, it is also possible that these and other scenarios could evolve.

The uncertainty regarding the course and details of federal legislation has several implications for Mountain Coal and other coal companies. First, the volume of carbon offsets that a coal mine might generate will depend on whether coal mine emissions are eventually capped or regulated, or allowed to generate offsets. Second, the value and rate of appreciation of carbon offsets will depend on the scope and timetable of a cap, and overall market demand for offsets. In the meantime, however, coal companies can take advantage of emerging opportunities to develop carbon offset projects as a result of growing offset certification frameworks in the U.S. The following section discusses existing certification programs and their implications for CMM projects.

V. U.S. Carbon Markets & Offset Certification Programs

A U.S. market for carbon has grown over the past several years in response to state and regional GHG policy development and the increased likelihood of federal GHG policy. This section provides an overview of the current state of the U.S. carbon market including the different buyers that are driving demand for offsets, leading certification programs for offset projects, and key implications for CMM projects.

Market Drivers
The carbon market was once dominated by corporations (that were mostly not large emitters) looking to voluntarily reduce their GHG footprint, improve sustainability, and possibly enhance brand image, has widened to include companies that are likely to be regulated under a government GHG program. This market, which is known as the "pre-compliance" carbon market, has seen large GHG emitters such as electricity generators, and large industrial and manufacturing companies participate in a range of initiatives, including quantifying corporate emissions, setting emission reduction targets, and enacting initiatives to reduce corporate emissions.

The following chart outlines the customer segments that currently participate in the U.S. carbon market.

Buyer Type	Examples	Desired Offset Criteria	Segment Demand
Voluntary	Google, News Corporation, offset retailers that sell credits to small businesses and individuals	"Charismatic" projects with co-benefits, such as forestry projects or livestock methane projects at farms	Voluntary demand has diminished with the economic recession and as corporate discretionary budgets are reduced
Financial	Hedge funds, commodity traders/banks	Low price, option value, low delivery risk	Demand from banks and speculators is increasing as they are willing to take more delivery and compliance eligibility risk
Pre-Compliance	Utilities, IPPs, large industrials and other companies that expect to be regulated under a cap-and-trade program	Likelihood of regulatory eligibility, high volume, and certainty of delivery	Pre-compliance demand is growing as buyers see an opportunity to buy compliance-grade credits at a discount to prices expected under a regulated market

Companies in the pre-compliance market purchase carbon offset credits in the hope that they will have value in a future compliance market. These pre-compliance buyers are expected to have the largest appetite for offset credits generated from coal mines over the next several years. CMM offset projects can provide these buyers with large-volume, cost-effective and permanent reductions that, if recognized under an eligible certification program, may have value in a federal compliance market. Because a large segment of this pre-compliance market is comprised of customers to the coal mine industry, many buyers are interested in purchasing offsets from projects developed by their current suppliers. Therefore, coal mines with large methane emissions are well-positioned to sell their carbon offset credits to the same buyers of their coal, such as utilities or other large industrials, which anticipate being capped under a cap-and-trade program.

Offset Certification Programs

Carbon offsets transacted in the pre-compliance market tend to be certified by one of a handful of certification programs. Certification programs provide project developers with offset project protocols that define the project requirements, and provide guidance on measuring and quantifying emission reductions. Programs also set rules and requirements for third-party offset project review and approval, and may also maintain established central registries that record approved projects and certified offset credits.

As GHG policy has evolved, it has become more apparent which projects registered (and offset credits "banked") under each of these certification programs may be recognized under a future federal cap-and-trade program. Further, the prospect for federal recognition has a direct impact on the price at which these credits trade in the market today. Please note that the Appendix at the end of this report contains a table with detailed information about these certification programs, including eligible project locations, prospects on compliance value, and current market pricing.

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A U.S. market for carbon has grown over the past several years in response to state and regional GHG policy development and the increased likelihood of federal GHG policy. This section provides an overview of the current state of the U.S. carbon market including the different buyers that are driving demand for offsets, leading certification programs for offset projects, and key implications for CMM projects.

Market Drivers

The carbon market was once dominated by corporations (that were mostly not large emitters) looking to voluntarily reduce their GHG footprint, improve sustainability, and possibly enhance brand image, has widened to include companies that are likely to be regulated under a government GHG program. This market, which is known as the "pre-compliance" carbon market, has seen large GHG emitters such as electricity generators, and large industrial and manufacturing companies participate in a range of initiatives, including quantifying corporate emissions, setting emission reduction targets, and enacting initiatives to reduce corporate emissions.

VI. Implications for Coal Mine Methane Projects

The chart below outlines the availability of an approved CMM protocol under each of the major certification programs in the U.S. today. It also includes Verdeo's assessment of the potential for projects registered under these programs to transfer into an emerging compliance cap-and-trade program at the state, regional, or federal level.

Certification Program	Protocol for CMM Projects	Type(s) of CMM Projects Recognized	Prospects for Compliance Value
Climate Action Reserve (the "Reserve")	Version 1 will be released in Oct 2009, and Version 2 (pipeline) is targeted for release in Feb 2010	***Recognized:*** Version 1 will recognize Oxidation of VAM, and utilization/combustion of CMM via all methods except pipeline utilization ***TBD:*** Pipeline utilization performance standard is under development	Very High
Voluntary Carbon Standard (VCS)	Yes – ACM0008, approved under CDM	***Recognized:*** VAM, Pre-Mine and Post-Mine Drainage	High
EPA Climate Leaders	In Development – release TBD	***TBD:*** VAM, Pre-Mine and Post-Mine Drainage	Very High
American Carbon Registry (ACR)	Looks to guidance by EPA and VCS	***Probable:*** VAM, Pre-Mine and Post-Mine Drainage	Moderate
Chicago Climate Exchange (CCX)	Yes	***Recognized:*** VAM, Pre-Mine and Post-Mine Drainage	Low

The Voluntary Carbon Standard (VCS) and Chicago Climate Exchange (CCX) have been the primary certification options available to developers of CMM projects. However, with forthcoming CMM protocols from both the Climate Action Reserve (Reserve) and EPA Climate Leaders program, developers of CMM offset projects will soon have two additional certification options that are backed by official government programs. This may increase the likelihood that projects using these protocols will have value in a future compliance market. Reserve offset standards are the only ones recognized by the State of California to generate offset reductions under a voluntary state reporting program, and may be recognized under California's cap-and-trade program, the WCI, and a federal program. As the Climate Leaders program is a voluntary GHG reduction program sponsored by the federal government, its forthcoming CMM offset protocol may also receive similar recognition. In that case, offset projects approved by Climate Leaders could receive early action recognition under a future federal program.

While the development of CMM protocols under the Reserve and Climate Leaders is encouraging, the degree to which these protocols foster new project development is contingent upon the specific CMM offset project types that will be recognized. The eligibility of different CMM project types to generate offset credits is discussed further in the following section.

VII. Coal Mine Methane Project Types

Project Types

There are three primary sources of fugitive methane emissions from underground coal mines and, thus, three primary types of emission reduction projects that, under different certification programs, are eligible to generate offset credits in the U.S. carbon market. The first source is ventilation air methane (VAM), the gas that is exhausted from a mine's main ventilation system that is dilute in methane concentration. While over 50% of GHG emissions from the coal mining sector are generated by VAM, this gas cannot be destroyed using traditional combustion technologies because of its low methane concentration. However, oxidation technology, which has been widely deployed in various industrial applications to destroy volatile organic compounds, can be used successfully to destroy VAM emissions. Verdeo has a prepared a separate report accompanying this one examining the state of the art in oxidation technology and potential applicability to the West Elk Mine.

A second source is methane drained from post-mine degasification systems. These systems extract methane from gob areas that form following the collapse of strata during longwall mining. Methane is drained primarily to avoid unsafe concentrations of methane migrating into the mine working areas. This gas may have potential application for electricity generation, on-site heat applications, or natural gas pipeline delivery, or, it could be incinerated with flaring technology to generate carbon offset credits. In addition, a third source is methane gas extracted in advance of mining through pre-mine vertical or in-mine horizontal boreholes. The methane extracted from this process can also be flared or utilized to generate carbon offset credits.

While there are some fugitive methane emissions from surface mines, these are a small fraction of overall methane emissions and are difficult to capture and quantify. Therefore, most certification programs focus on underground coal mines.

Continued on Next Page

Additional information on the three primary sources of coal mine methane and project types that can be developed to reduce these emissions is detailed below.

Methane Source	What it Entails:	Utilization Technology	Destruction Technology	Current U.S. Examples
Ventilation Air Methane (Active Mine)	Oxidation technology is used to destroy ventilation air with very low methane concentrations VAM, the dilute methane emitted from central mine ventilation shafts, is responsible for over 50% of methane emissions from the mining sector in the U.S. With the exception of just two mines that developed VAM abatement projects in the U.S., all VAM from mines is released directly to the atmosphere. Therefore, any new offset project development that occurs to abate VAM emissions is likely to be considered highly additional under existing offset certification programs.	Low-grade heat Electricity generation	Thermal oxidation	Mine No. 4, Alabama (active) (Jim Walter Resources) Windsor Mine (inactive), West Virginia (CONSOL)
Post-Mine Degasification (Active or Abandoned Mines)	Post-mine drainage or methane recovery from vertical gob wells is employed to extract methane from the gob as mining progresses. Vertical wells can be drilled from the mine surface into the gob areas and pumps installed to extract methane that would otherwise flow into the working areas of the mine. It is also possible to drill ahead of the gob formation. While gob wells can initially produce very high concentration methane, many gob wells produce methane that requires conditioning to remove nitrogen, carbon dioxide, oxygen, and other impurities for pipeline delivery. Most mines that extract methane from vertical gob well drainage vent this methane to the atmosphere.	Gas conditioning, for pipeline delivery or onsite use Electricity generation Heat generation	Pipeline delivery Incineration with enclosed stack flare or thermal oxidation	Blue Creek Mines, Alabama (Jim Walter Resources) Blacksville No. 2 Mine, West Virginia (CONSOL)
Pre-Mine Degasification (Active Mine)	Pre-mine drainage entails recovering methane gas from the coal seam and surrounding strata in advance of mining either through vertical wells or in-mine horizontal boreholes or longhole horizontal boreholes. Because recovered methane is not mixed with ventilation air, the extracted methane is occasionally of pipeline-grade quality. According to the EPA, six of the underground coal mines in the U.S. that have employed methane drainage systems are using vertical pre-mine wells, nine are using horizontal borehole drainage, and two are using longhole horizontal borehole drainage.[8]	Gas conditioning, if needed, for pipeline delivery or onsite use Power generation Heat generation	Pipeline delivery Incineration with enclosed stack flare or thermal oxidation	Buchanan Mine, Virginia (CONSOL) Cumberland and Emerald Mines, Pennsylvania (Foundation) Oak Grove and Pinnacle Mines, Alabama and West Virginia (Cliffs)

Additionality

Additionality is a key consideration for mines considering the development of emission reduction project. Projects that are additional and, therefore, eligible to generate carbon offset credits, are those that would have not likely been implemented without the incentive of a market for GHG emission reductions.

Additionality can be measured using a performance standard or on the basis of evaluating specific characteristics of individual projects (project-specific). A performance standard is typically designed by an offset program administrator to set a clear, upfront threshold for project eligibility. For example, a performance standard for a VAM oxidation project type could establish eligibility by assessing the number of mines that collect and oxidize VAM, and evaluate whether such practice is standard throughout the mining industry. In contrast, project-specific additionality tests require each individual project to demonstrate why it is additional. While these tend to entail

[8] Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 2002-2006. U.S. Environmental Protection Agency, September 2008.

more subjective evaluation of eligibility on the part of an offset program administrator, project-by-project reviews can help account for projects that may fall as an exception to a performance standard rule. While the international offset market under the Clean Development Mechanism (CDM)[9] has historically adopted a project-by-project approach to evaluating additionality, a federal U.S. program will likely adopt performance standard-based approaches based on precedents set by other pre-compliance offset programs[10].

With the exception of just two mines (one active) that have developed VAM abatement projects in the U.S., all VAM from mines in the U.S. is released directly to the atmosphere. Therefore, new offset project development that occurs to abate VAM emissions is universally likely to be considered additional under any of the current offset certification programs, as well as under a future federal program. In addition, projects that involve the destruction of methane extracted from pre- and post-mine degasification systems through flaring, electricity generation, on-site heat generation, or other non-pipeline utilization applications are likely to be seen as additional by certification programs because they are not prevalent in the U.S. The majority of mines that have existing systems to collect methane from degasification systems do so only for pipeline utilization. Some of these mines generate carbon offset credits along with pipeline gas sales, though some of them only rely on the revenue from pipeline sales. For a mine that considers developing a new pipeline utilization project, its ability to generate carbon offset credits will depend on the certification program used and individual circumstances of the project.

For example, while the performance standard-based CMM protocol in development by the Reserve is anticipated to recognize as additional all non-pipeline utilization projects, it is not clear whether all gas pipeline utilization projects will be considered additional. Most likely, the Reserve will set strict parameters for the types of mines that can receive carbon offset credits for pipeline utilization projects. However, certification programs like CCX universally recognize all methane collection and combustion project types, including all pipeline utilization projects. Programs like the VCS fall somewhere in between; as VCS takes a project-specific approach to evaluating additionality, mines pursuing pipeline utilization can try to demonstrate that, based on mine-specific characteristics, collection and utilization is not business-as-usual.

VIII. Implementing Coal Mine Methane Projects

While each CMM carbon offset project has its own unique set of characteristics, all CMM projects must follow a similar process to generate a tradable carbon offset credit. A project must be sufficiently documented and developed with a strict eye towards the rules set forth by a specific offset protocol and certification program. In general, all processes will follow the following six steps.

Step 1: Select certification standard and offset protocol
Certification programs typically have a pre-approved set of protocols that are available for public use and applicable to specific offset project types. These protocols provide guidelines for determining individual project eligibility, quantifying baseline emissions and emission reductions, and conducting monitoring of emission reductions over the life of the project. Other issues specific to carbon projects, such guaranteeing performance of emission reductions, ownership of emission reductions, and demonstrating additionality, are also typically addressed in the project protocol.

There are several different certification programs in the U.S. and a project developer will need to take multiple factors into consideration when choosing a program under which to develop and register a CMM offset project. For instance:

- **Probability of Acceptance:** A certification program and offset protocol that fits the parameters of a given CMM offset project should be selected. For example, some programs and protocols have strict requirements about project state dates or specific project types that are eligible.

[9] The CDM is a flexible mechanism of the European Union Emissions Trading Scheme (EU-ETS), whereby regulated companies in Europe can purchase Certified Emissions Reductions (CERs) from approved offset projects in developing countries to help meet their GHG reduction obligations.
[10] Offset project protocols recognized under the EPA Climate Leaders Program and the Climate Action Reserve utilize performance-based standards to assess project eligibility and additionality.

- **Rigorous Standards:** Stricter protocols for the same CMM project type tend to command a price premium in the marketplace, so it often makes sense to choose the strictest protocol possible if a project can meet the protocol requirements.
- **Compliance with Future Regulation:** Consideration should be given to whether the certification program may be recognized under a federal compliance program, as credits in a compliance program will likely be more valuable if and when a federal cap-and-trade program is implemented. For instance, the Reserve has been singled out in the House's *ACESA* as a certification program for which projects registered will be eligible to receive compliance-grade offset credits under a federal cap-and-trade program.
- **Cost:** Cost is usually not a primary consideration when choosing a certification program. Registries typically charge an annual account maintenance fee for each project registered on the registry, typically around $500. There are also small fees when a credit is issued or transferred, and which is discussed in Step 6. However, if a project is being developed for which an existing approved protocol does not apply, a developer may incur significant costs to write a new project protocol and have it certified. <u>The cost of developing a new protocol may range from $40,000 - $100,000, depending on the range of services required and the process to certify a new protocol.</u>

For more detailed information on U.S. certification programs, please see the accompanying Appendix, "Comparison of Leading U.S. Carbon Offset Certification Programs".

Step 2: Develop carbon project documentation
In order for a project to be approved by a certification program, project developers must draft project documentation that follows the prescribed rules of the protocol and program. This documentation, which has slightly different requirements under the various certification programs, typically requires a project developer to provide the following project and technical data including:
- Detailed description of the CMM project
- Demonstration as to why the emission reduction project is not "business-as-usual"
- Calculation of baseline emissions and emission reductions
- Detailed monitoring methodology and plan
- Proof of ownership of emission reductions

Step 3: Validate project documentation & register project
The project document is then submitted to an independent third-party that has been approved by the certification program to conduct project validations. The project validation, which is comparable to that of an ISO certification or third party financial audit, entails a desktop review of the project documentation and may include a site visit, to determine whether the project meets the requirements of the offset protocol and certification program. If a validator determines the project does meet all necessary requirements, the project becomes validated and is eligible to generate carbon offset credits. After this stage, projects are then registered on the chosen or designated registry of the certification program.

Each certification program has a slightly different list of eligible validators, all of which are generally approved to conduct validations of specific offset project-types based on demonstrated expertise. While some of these companies may also provide other offset project-related consulting services, a company can only be hired as a validator if it has not provided any consulting services for a project.

- **Climate Action Reserve** – The Climate Action Reserve will release its list of eligible validators following the release of Version 1 of its CMM protocol in October 2009. The list will eventually be available at: <u>http://www.climateactionreserve.org/how-it-works/verification/connect-with-a-verification-body/</u>.

- **Voluntary Carbon Standard** – All validators recognized to conduct validations for mining-related projects (Scope 8) under the Kyoto Protocol's Clean Development Mechanism are eligible to conduct CMM project validations under the VCS. While Det Norske Veritas, TÜV SÜD, and SGS United Kingdom (SGS) are the best known eligible validators, several other companies have recently been approved to conduct mining project validations, including the U.S.-based First Environment, Inc. The complete list of eligible validators is available at: <u>http://www.v-c-s.org/validators.html</u>.

- **EPA Climate Leaders** – At this time, the EPA staff conducts its own project validations or reviews and does not rely on assistance of third-parties.

- **American Carbon Registry** – The American Carbon Registry has approved several companies to conduct project validations for a range of project types, though the companies with the most mining-related experience are First Environment, Inc. and Ruby Canyon Engineering. The complete list of approved validators is available at: http://www.americancarbonregistry.org/carbon-accounting/verification.

- **Chicago Climate Exchange** – The Chicago Climate Exchange has approved Marshall Miller and Associates, Raven Ridge Resources Incorporated, Ruby Canyon Engineering, Summit Engineering, Inc, and TÜV SÜD to conduct verifications of emission reductions from CMM projects[11]. The list of eligible verifiers is available at: http://www.chicagoclimatex.com/content.jsf?id=1803.

Costs for validation services will vary, though estimates for one-time project validation typically range between $20,000-30,000.

Step 4: Operate project
Project development activities are generally conducted in a parallel process with steps two and three above. As the project documentation is developed and approved, the developer is also at work designing the project, procuring the necessary equipment and constructing the project. In fact, project commissioning and operations can sometimes commence prior to validation. Typically certification programs have rules that require validation to be complete within a certain amount of time following the project start date. Once the project begins operating, the ongoing collection and reporting of emissions reduction data also commences.

Step 5: Periodically verify GHG reductions
Reductions of CMM emissions do not formally become carbon offset credits until the reductions have been verified by an independent third-party that is responsible for auditing the emission reduction data. Periodic verification is a process to review and confirm the number of emission credits generated over a period of time. The verification of offset credits is typically performed on an annual basis, although it is possible to verify more often (and thus create offset credits that are available for sale more often). A CMM project developer will weigh the costs and benefits of additional verifications prior to making this decision. The cost of verification services typically ranges from $10,000-15,000 per verification, and can be performed by the same companies that are certified to conduct project validations (see eligible list of validators under Step 3).

Step 6: Register, issue and sell offset credits
Once emission reductions have been verified as carbon offset credits, they can be registered under a certification program's registry and issued into the owner's account. Certification programs such as the Reserve[12] or CCX[13] have one designated registry where offset projects and credits are registered, whereas programs like VCS[14] allow project developers to register projects and offset credits in one of three designated registries. Once an offset credit has been issued, the owner is then free to sell the credits in the marketplace, "bank" the credits for future use, or retire the credits if they want to make the emission reductions permanent. There are a variety of outlets for selling registered offset credits. A seller can find buyers directly, use a third-party broker, or use one of a growing number of exchanges that list offset credits.

Registries generally charge an annual account maintenance fee for each project registered on the registry, which is typically around $500. Registries also generally charge between $0.05- $0.07 for each offset credit that is verified

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[11] The CCX Offsets Committee reviews and approves eligible offset projects, and only requires third-party verification of emission reductions. Information on the verification process and estimated cost for services can be found under Step 5.
[12] The Climate Action Reserve operates one designated registry for certified offset projects. This registry is operated by APX Inc. New accounts can be applied for by accessing: http://www.climateactionreserve.org/open-an-account/.
[13] The CCX operates its own registry, which can only be accessed as a member of CCX. For more information about CCX membership, please visit: http://www.chicagoclimatex.com/content.jsf?id=65.
[14] The VCS allows project developers to register projects under any of three different registries, APX Inc., Caisse des Dépôts, and TZ1. For more information about these registries, please visit: http://www.v-c-s.org/projects.html.

and issued, and an additional $0.02 - $0.05 when an offset credit is sold from one party to another. Additional transaction costs are added depending on the method of sale. For example, emission brokers usually charge up to 3% of the total cost transacted between parties, while exchanges typically have annual membership fees as well as initial margin and maintenance margin requirements.

IX. Carbon Offset Credit Price Projections

Drivers of Current Offset Prices

Current prices for carbon offset credits range anywhere today from $0.25 to $8 per metric ton, and this pricing is based on a range of factors. Aside from the current uncertainty regarding the future course of federal GHG policy, the three most significant determinants of current offset prices in the U.S. are: 1) the certification program under which an offset is certified; 2) the type of project that generates the offset; and 3) vintage of the offset, or year in which the offset was created.

- ***Certification Program:*** The certification program under which credits are issued is a primary driver of price because certification programs have varying degrees of offset quality and likelihood of acceptance into a federal cap-and-trade program. Credits issued under the Reserve currently trade at $6-8 per metric ton, the highest market prices in the U.S., due to the perceived likelihood of acceptance into a federal regime. In contrast, the CCX is listing credits for $0.25 per metric ton due to the growing market perception of CCX issuing lower-quality credits that will not be accepted in a future compliance market. VCS credits are trading in the range between $3-5 per metric ton, and prices for credits under the ACR are likely to fall somewhere in the range of trading prices seen for the Reserve and CCX.

- ***Offset Project Type:*** While there is no precise rule about the order of projects that command the highest market pricing, different types of offset projects (e.g., livestock methane, forest carbon sequestration, coal mine methane) can command different prices in the market. Many buyers, particularly those in the voluntary carbon market, prefer to buy credits from projects with a philanthropic image, such as forest sequestration projects. This is changing as the U.S. moves toward a "pre-compliance" market and buyers start to demand credits from project types that are the most likely to be included in federal legislation.

- ***Vintage:*** Another factor that is important to pre-compliance buyers is vintage, which is the year that a carbon credit is generated. The *ACESA*, passed in the House of Representatives, for example, included language to clarify that only projects implemented and registered under qualifying programs[15] after January 2001 would be eligible to receive early action credits under a cap-and-trade program, and further, that actual compliance-grade offset credits awarded for those projects would only be for emission reductions generated in 2009 and beyond. While this language may not be the language of a final cap-and-trade bill passed by Congress, the carbon market has responded in short-order by already signaling a preference for credits generated from vintages 2009 and forward.

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[15] Programs deemed eligible by the language of the *ACESA* were those developed as part of a pre-existing state program (e.g., the Reserve or RGGI) and those potentially eligible, if approved by the EPA, were programs such as the VCS and ACR.

Current Offset Credit Price Estimates

The following chart outlines the range of publicly available prices that have been published for offset credits under the following programs.[16] We note that these prices are always subject to change, and do not account for private bi-lateral transactions between parties that have not been disclosed.

Certification Program	Climate Action Reserve	Voluntary Carbon Standard	EPA Climate Leaders	American Carbon Registry	Chicago Climate Exchange
$/per metric ton	$6-8	$3-5	Not reported	Not reported	$0.25-3

Drivers of Future Offset Prices

At the most basic level, future demand and pricing for carbon offsets will depend on whether federal legislation is enacted, and how it is designed. For example, legislation introduced to date has varied across a range of issues, including the level of the emission cap, timeframe for reductions, the amount of emission allowances that will be allocated and auctioned to capped facilities, and the number of domestic and international offsets that will be allowed into the system. As the shape of future legislation remains uncertain, future offset prices could range significantly under different design scenarios.

- ***Level of the Cap:*** The level of the cap will influence the level of emission reductions required across the economy and hence, the number of offset credits that will be in demand by facilities to comply with the cap. For example, the *ACESA* has reduced the number of emission reductions needed under the cap from the previous Waxman and Markey Discussion Draft. If the level of the cap changes in future versions of climate legislation, it should have a resulting impact on prices for carbon offset credits.

- ***Number of Offsets Allowed:*** Offsets are designed to serve as a cost-containment mechanism for a cap-and-trade program. For example, according to EPA analysis of the Waxman-Markey Discussion Draft, disallowing use of international offsets alone would almost double the price of allowances under the program, while also decreasing demand for offsets. Assuming that the emissions cap creates demand for emissions reductions, increasing the amount of offsets that can be used by capped facilities will increase demand for offset credits and lead to higher prices for offsets. The lesson learned under the European Union's cap-and-trade Emission Trading System (EU-ETS) is that offsets tended to trade at a discount to allowance prices, which averaged 25% during the second phase of EU-ETS.

- ***Auction vs. Allocation of Allowances:*** In President Obama's federal budget, emission allowances were to be fully auctioned by the federal government. In the *ACESA*, almost all of the allowances will be allocated for free to facilities covered under the cap. The extent to which the manner of distributing emission allowances has an effect on the price of carbon offset credits is debatable, though more free allocations to companies could lead to lower demand for offset credits. Ultimately, the price of offsets will driven by demand for reductions and whether companies can procure offset credits at a price lower than that of additional emission allowances.

- ***Other Governing Factors:*** There are many other provisions that could have a substantive effect on the price of offsets under a federal program. These include the presence or absence of a discount for offsets vs. allowances (i.e., requiring the submission of 1.25 offsets to receive credit for reducing 1.0 ton of emissions), the composition of the industries that will be covered under the cap, and the presence or absence of a "collar" on allowance prices (i.e., a government mechanism that sets a minimum and maximum price at which allowances can trade under a cap-and-trade program).

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[16] Prices for the Climate Action Reserve, Voluntary Carbon Standard, and Chicago Climate Exchange represent those in the bid/ask range reported by TFS Energy and Evolution Markets during June-July 2009. The $0.25 price listed for the Chicago Climate Exchange reflects the exchange-listed price reported on its website as of September 3, 2009.

Future Offset Credit Price Projections

The following chart highlights the outcome of three potential legislative scenarios and associated estimates of future carbon offset credit prices in 2015 and 2020 under these scenarios.

Reference Case	Future GHG Policy Outcome Scenario	2015 Price Range Estimate ($/ton)	2020 Price Range Estimate ($/ton)
High Case	20% reduction of federal GHG emissions by 2020 *(Waxman-Markey Discussion Draft)*	$11-14 *(EPA estimate)*	$14-18 *(EPA estimate)*
Base Case	17% reduction of federal GHG emissions by 2020, more free allocations of allowances given to capped emitters than in High Case *(American Clean Energy and Security Act of 2009)*	$13 *(EPA estimate)*	$16 *(EPA estimate)*
Low Case	Federal gridlock that produces no policy, or, a federal cap-and-trade program with over-allocation of allowances *(Offsets traded in state/regional compliance markets (e.g., WCI) or voluntary markets)*	$7-10 *(Verdeo estimate)*	$11-13 *(Verdeo estimate)*

The high case and base case scenarios and estimates for offset prices in 2015 and 2020 are based, respectively, on the EPA's economic modeling of the Waxman-Markey Discussion Draft[17], and the EPA's economic modeling of the *ACESA*, after it was passed out of the House Energy and Commerce Committee[18]. In the both the high and base cases, price projections are based on the assumption that cap-and-trade legislation is passed and carbon offset credits can be used for compliance. As previously discussed, these figures only represent prices projected by the EPA in relation to these specific pieces of proposed legislation. We anticipate that price projections will continue to evolve as the Senate takes up consideration of legislation this fall.

In the low case scenario, Verdeo assumes a scenario where either federal GHG policy is not enacted and offset trading remains limited to regional and voluntary markets. Alternately, a low case scenario could represent one where a federal GHG program is enacted but a high cap, resulting in low demand for offset credits, or one where a price collar is implemented, effectively restricting the price at which offset credits could trade. As regional programs are still under development, forward modeling of offset prices under these frameworks is very limited. We therefore assume future projected prices are would be higher than what we currently see in the voluntary market, but lower than what we could anticipate under a federal program. In general, there is a high level of uncertainty associated with future pricing for offset credits in the event a federal GHG program is not enacted.

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[17] "EPA Preliminary Analysis of the Waxman-Markey Discussion Draft: The American Clean Energy and Security Act of 2009 in the 111th Congress", April 20, 2009. Available at: http://www.epa.gov/climatechange/economics/pdfs/WM-Analysis.pdf

[18] "EPA Analysis of the American Clean Energy and Security Act of 2009 H.R. 2454 in the 111th Congress", June 23, 2009. Available at: "EPA Preliminary Analysis of the Waxman-Markey Discussion Draft: The American Clean Energy and Security Act of 2009 in the 111th Congress", April 20, 2009. Available at: http://www.epa.gov/climatechange/economics/pdfs/WM-Analysis.pdf

Appendix: Comparison of Leading U.S. Carbon Offset Certification Programs

Program	Eligible Project Locations	CMM Protocol	Project Eligibility Evaluation Method	State/Regional/Federal Recognition
Climate Action Reserve (Reserve)	• All U.S. states • Possible expansion to Canada and Mexico	• The Reserve is developing a protocol for CMM projects, V. 1 expected to be released Oct. 2009 • All non-pipeline utilization projects will be eligible under V. 1 • V. 2 (for pipeline) will be released in Feb. 2010	• Explicitly defines project-type eligibility in its protocols using a performance-standard approach	• Reserve standards are only standards to be recognized by the State of California for voluntary GHG reductions • High probability of protocols being recognized under the State of California's cap-and-trade program, and the Western Climate Initiative • Early action recognition for certified projects is being discussed at the federal level, but no definitive decisions have been made
Voluntary Carbon Standard (VCS)	• International and all U.S. states	• VCS recognizes all CDM methodologies and CAR protocols • ACM0008 approved for CMM, and includes VAM, pre-mine, and post-mine drainage abatement/utilization	• Developer demonstrates eligibility of an individual project using common practice, financial, technology, and market barrier additionality tests	• Early action recognition for VCS certified projects is being discussed at the federal level, but no definitive decisions have been made
EPA Climate Leaders (CL)	• All U.S. states	• EPA is developing a protocol for CMM projects, expected to be released in 2009 • Project-type eligibility (VAM, post-mine and pre-mine degasification abatement/utilization) is TBD	• Defines project-type eligibility using a performance-standard approach	• Early action recognition for VCS certified projects is being discussed at the federal level, but no definitive decisions have been made
American Carbon Registry (ACR)	• All U.S. states	• ACR has proprietary protocols, and recognizes existing protocols (such as CDM)	• Developer demonstrates additionality using EPA and IPCC Guidelines and Good Practice standards	• Early action recognition for VCS certified projects is being discussed at the federal level, but no definitive decisions have been made
Chicago Climate Exchange (CCX)	• All U.S. states	• Protocol is applicable to VAM, pre-mine, post-mine, and abandoned mine abatement/utilization	• All projects types are eligible	• Early action recognition for VCS certified projects is being discussed at the federal level, but no definitive decisions have been made

<u>EXHIBIT J</u>

Methane Monitoring Memorandum

MOUNTAIN COAL COMPANY, L.L.C.

West Elk Mine
MEMORANDUM

To/Location:	**Gene DiClaudio**	**Don Vickers**
From/Location:	**John Poulos**	**Wendell A. Koontz**
Date:	**August 7, 2009**	
Subject:	**2009 R2P2 West Elk Mine Methane Monitoring**	

Mountain Coal Company (MCC) conducts continuous and systematic monitoring for methane concentrations and volumes at it's West Elk Mine exhaust fans and Methane Drainage Wells (MDWs). The monitoring systems are in place to ensure the safety of the miners and comply with federal regulations.

Exhaust Fans

The three existing exhaust fan installations, Sylvester Gulch, Shaft #2, and Shaft #3 are monitored continuously for methane concentration utilizing electronic methane sensors. These sensors report to the CONSPEC computerized monitoring station which is manned 24 hours per day.

Additionally, the exhaust air course is sampled weekly by qualified miners by collecting bag samples of the air for analysis by gas chromatograph. The volume of air is determined by measurements from hand held anemometers at the same time.

Monthly pitot tube measurements are taken by West Elk's Ventilation Engineer at the exhaust fans. The measurements record fan pressure and verifies the weekly measurements of the qualified miner. Data of methane concentration and quantity is verified and summarized by the MCC Engineering Department.

Methane Drainage Wells

Methane concentration and volume from MDWs is tightly monitored. Each MDW has electronic monitoring that radio transmits flow data to CONSPEC monitoring station. Flow rates are checked and recorded every two hours. Mine personnel physically inspect the operating MDWs daily and also record flow rates. Twice weekly, bag samples are collected for gas chromatograph analysis. The data is checked by the MCC Safety Department and summarized by the MCC Engineering Department.

Exhaust Shaft #4

Methane monitoring for the new Exhaust Shaft #4 will be similar to the three existing Exhaust Fans when it is commissioned 4Q2009. Shaft #4 will be equipped with continuous monitoring of methane concentration via the electronic CONSPEC system with weekly air volume measurements and bag samples. The two existing Exhaust Fans, #3 and #4, will be converted to intake fans and methane monitoring will be discontinued at these locations.