Pre-feasibility Study for Coal Mine Methane Drainage and Utilization at Alardinskaya and Uskovskaya Coal Mines

Kuzbass Coal Basin, Russian Federation

U.S. Environmental Protection Agency
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Acronyms and Abbreviations

Btu	British thermal unit
C	Celsius
Bcm	Billion cubic meters
CAPEX	capital expenditure
CBM	coalbed methane
CER	Certified Emission Reduction
CH_4	methane
CMM	coal mine methane
CMOP	Coalbed Methane Outreach Program
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
GHG	greenhouse gas
GMI	Global Methane Initiative
IRR	internal rate of return
kcal	kilocalorie
kg	kilogram
km	kilometer
M	million
Mcf	million cubic feet
MJ/m^3	million joules per cubic meter
mm	millimeter
Mt	million tonnes
MW	megawatt
MWe	megawatt electrical power
MWhr	megawatt hour
MWth	megawatt thermal power
NPV	net present value
t	tonne
tCO_2e	metric tons of carbon dioxide equivalent
tonne	metric ton
VAM	ventilation air methane
VER	verified emission reduction

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1.0 Executive Summary

In 2012, as part of its commitment to support the Global Methane Initiative (GMI), the U.S. Environmental Protection Agency's Coalbed Methane Outreach Program (CMOP) commissioned a pre-feasibility study to examine the potential for a coal mine methane (CMM) recovery and utilization project at a Russian coal mine. GMI is a voluntary, multilateral partnership that aims to reduce global methane (CH_4) emissions and to advance the abatement, recovery, and use of methane as a valuable clean energy source. GMI achieves its goals by creating an international network of partner governments, private sector members, development banks, universities and non-governmental organizations in order to build capacity, develop strategies and markets, and remove barriers to project development for methane reduction, including CMM in Partner countries. More information about GMI and coal sector activities can be found at www.globalmethane.org.

Methane emissions from the Kuznetsk (Kuzbass) coal basin account for about 70% of total methane emissions from Russia's entire coal mining sector and represent an attractive opportunity for CMM mitigation projects. Yuzhkuzbassugol United Coal Company, a division of the EVRAZ steel and mining group, is the eighth largest underground coal producer in Russia, producing approximately 11 million tons in 2012. Two of Yuzhkuzbassugol's eight coal mines operating in the Kuzbass—the Alardinskaya and Uskovskaya coal mines—were selected for a pre-feasibility study due to their favorable characteristics and operations, and because most of the drainage gas produced is higher in methane than at other Yuzhkuzbassugol mines.

The Alardinskaya and Uskovskaya coal mines operate within the Kemerovo Oblast of the Russian Federation about 200 kilometers (km) apart, and both mine high-grade thermal and coking coal from carboniferous strata. Alardinskaya is mining at about 700 meters (m) depth with two longwall shearing machines, and Uskovskaya is mining at about 300 m depth with a single longwall machine. Both mines are producing about two million metric tons (MMT) of coal per year, and have specific emissions of approximately 35 cubic meters (m^3) of methane per metric ton of coal mined.

Both mines have extensive pre-mine methane drainage operations using in-mine drilling. Each mine has several drilling teams of four persons each, with each team operating two drilling rigs. As the longwall panels are developed (six to 18 months in advance of mining), the drilling teams drill about 250 to 325 parallel holes along the panel (76 millimeter in diameter), with each hole measuring 200 meters long. These boreholes are networked into an underground piping system that then takes the gas to the surface through a borehole. Pump stations at the surface apply vacuum pressure to recover the gas.

The following sections summarize some of the key technical and financial aspects of each mine and the study's recommendations.

1.1 Alardinskaya Mine

Alardinskaya is a prospective candidate for developing a power generation project from the PGM-Lennetal pump station, which consistently produces medium-quality gas (~40% methane) at approximately 45 m^3/minute. This amount of gas would supply a 3 megawatt power station. Pro forma economic analysis suggests that an internal rate of return (IRR) of 7.6% could be generated without income from greenhouse gas (GHG) emission reduction credits, increasing to 12% with revenue from a carbon price of $1 per ton of carbon dioxide equivalent (CO_2e) per year, while a 25% IRR could be realized with a carbon price of $5.20 t$CO_2$e/year. This project could reduce emissions by 77,000 tCO_2e/year, and the power would offset grid power by another 10,000 tCO_2e/year (for a 10-year project life).

The high methane content of the bleeder shaft at Alardinskaya could provide an incentive for ventilation air methane (VAM) thermal oxidization at the bleeder shaft. If concentrations reach 1% methane, there is the potential to reduce emissions by more than 180,000 tCO_2e/year and achieve a 25% IRR[1] at a carbon price of $5.21/t$CO_2$e.

Furthermore, there might be opportunities to improve methane recovery and more rapidly pre-drain the methane from seams below the currently mined seams by drilling cross-measure boreholes from the upper seam into the lower seam(s). These seams will "relax" after the removal of the upper seam coal, which will enhance the permeability of the lower coal and allow degassing of that coal seam for a longer period before mining.

1.2 Uskovskaya Mine

Uskovskaya is capturing similar methane volumes from the drainage system as Alardinskaya; however, the methane content is averaging 27%, which is below the 35% required for use in power generation equipment. Unless methane quality can be improved, a power generation project is not feasible.

Uskovskaya's ventilation air system consists of a bleeder shaft with high concentrations of methane. There is the possibility of using drained gas to replace the ventilation air heating system, which is currently using coal-fired furnaces. If the pump stations are relatively nearby, heating by drained gas may be economically advantageous.[2] Analysis showed that a carbon price of $1.00/t$CO_2$e provided an IRR of 13.8% and that a price of $1.80/t$CO_2$e would achieve a 25% IRR.

VAM economic analysis shows better-than-average performance for VAM projects relative to carbon price because of the richness of the VAM from the bleeder shaft. However, a carbon price of $1.00/t$CO_2$e produced a 0% IRR. A price for GHG emission reductions of $5.21/t$CO_2$e is necessary to make this economically feasible with a 25% IRR.

[1] CMM recovery and utilization projects typically require a higher premium for IRR due to uncertainties in resource recovery and commodity prices. For this study, a 25% IRR was selected as comparable to other similar project types. A more detailed financial analysis may result a lower IRR and prove economically feasible.
[2] The distances from pump stations to intake air shafts were not available for the study.

1.3 Observations and Recommendations

The study finds that both mines show good potential for methane capture and utilization; however, additional information should be gathered and analyzed to reduce uncertainty and provide a sound basis for investment.

Overall, both mines should initiate regular monitoring, recording and storage of digital data on gas rates and methane concentration/content from the pumping stations and the bleeder shafts (data is currently recorded manually in notebooks). The mines should also consider additional gas drainage techniques such as in-mine long-hole boreholes and/or cross-measure drilling into seams below the primary mined seams to more rapidly degas those seams before mining and reduce emissions into the gob of the active seam.

More specific observations and recommendations for each mine are provided below.

1.3.1 Alardinskaya Mine

- The study relied on data reported for 2010 at the PGM-Lennetal pumping station for the low, mid-, and high volumes and methane content in order to conclude that a power generation project could produce 3 megawatts. 2010 is the year of lowest degas volume (14.7 m^3/min CH_4); the following year reported more than double that volume (37.3 m^3/min CH_4). If the 2011 value remains consistent, the project could be significantly larger (assuming adequate gas quality).
- Experimentation with drilling into the seams below the actively mined panel before mining might degas the seam to some extent, and result in increasing gas into the gob area, and significantly degas the seam rapidly after the panel has been mined and the floor has heaved (i.e., relaxing the seam below). The 30 m separation of the primary seams (i.e., 30 m between 3a and 6, and also between 6 and 7) is well within the mechanical influence produced by mining of the coal on either side.
- There is considerable uncertainty in the range of methane content at the bleeder shaft and at the PGM-Lennetal pumping station. A more robust data collection effort would enable a better defined analysis. For example, daily sampling from these locations for at least a month would provide better definition of the variability of the methane concentration and flow rate.

1.3.2 Uskovskaya Mine

- Investigate the feasibility of using the drained gas to fuel the mine air heating furnaces at the intake air shafts, displacing coal as the fuel. The project feasibility will primarily depend on the distance that the gas must be moved from the pumping stations to the intake air shafts.
- Improving the methane content of the drained gas so that it is consistently above 35% will allow evaluation of a power generation project. This could possibly be done through improved procedures to ensure piping integrity to reduce leaks (mine air ingress). Grouting procedures could also be modified to ensure borehole integrity, and actively managing the suction pressure might also improve methane concentration.

- Analyze the potential for capturing gas from the surface gob wells. Gob gas production per well along a panel can be short-lived, and capturing and transporting the gas from each well can be expensive and problematic in cold weather. However, some mines in the United States plug and abandon all but one strategically located well, which is operated to manage the gas buildup in the sealed gob area. These wells can be networked with buried pipe to a central facility for use over several years. Such a scheme should be investigated to determine how the mine should be managed to allow for capture and utilization of the recovered gob gas via a surface gathering system.
- Because the seam is too thick for the longwall machine to mine, a significant amount of coal is left on the panel's floor. This floor coal potentially releases significant amounts of gas into the gob area after the panel has been mined and should be further investigated. Also, seam 6 is within 30 m of seam 3a and could also release gas into the gob. The scope of this study did not allow for verification; the mine operators should verify the amount(s) of gas through targeted drilling within the mine.

2.0 Background

The Kuznetsk Coal Basin (Kuzbass) is located within the Kemerovo Oblast in southwest Siberia (**Figure 1)**. The Oblast is the largest industrial region in Russia and has some of the world's largest coal deposits. Coal-bearing seams extend over an area of 10,309 square miles (26,700 km^2) and reach to a depth of 5,905 feet (1,800 m).

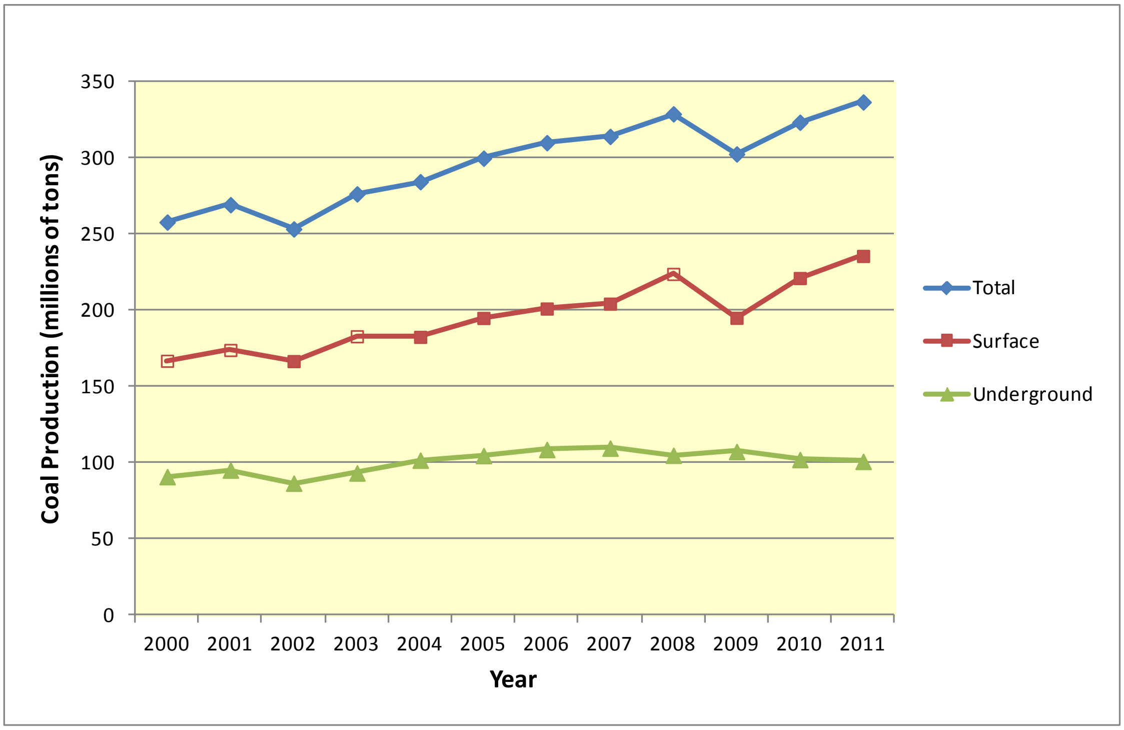
Figure 1. Location of the Kuzbass region

With 173 billion tons, Russia holds the world's second largest recoverable coal reserves behind the United States (**Figure 2**). In 2010, Russia produced approximately 323 million tons of coal, making it the sixth largest coal producer in the world. The corresponding CMM emissions were estimated to be 3.2 billion m^3, of which 2.0 billion m^3 were emitted from underground mines.[3]

In 2009, 57 of Russia's 98 underground coal mines were considered either "Category 3" mines, with methane emissions of 10 to 15 cubic meters per ton (m^3/t) of coal mined, or "Super Hazardous" mines, with methane emissions greater than 15 m^3/t. Of these mines, approximately 25 deployed degasification systems in 2009. While underground mining represents 30% of Russia's total coal production, forecasts predict an increasing share of coal production from deeper underground mines, leading to increased methane emissions.

[3] http://unfccc.int/di/DetailedByParty/Event.do?event=go

Figure 2. Russian coal production, 2000–2011



Source: Ministry of Energy of Russian Federation, CDU TEK, Rosinformugol, September 2012

3.0 Introduction

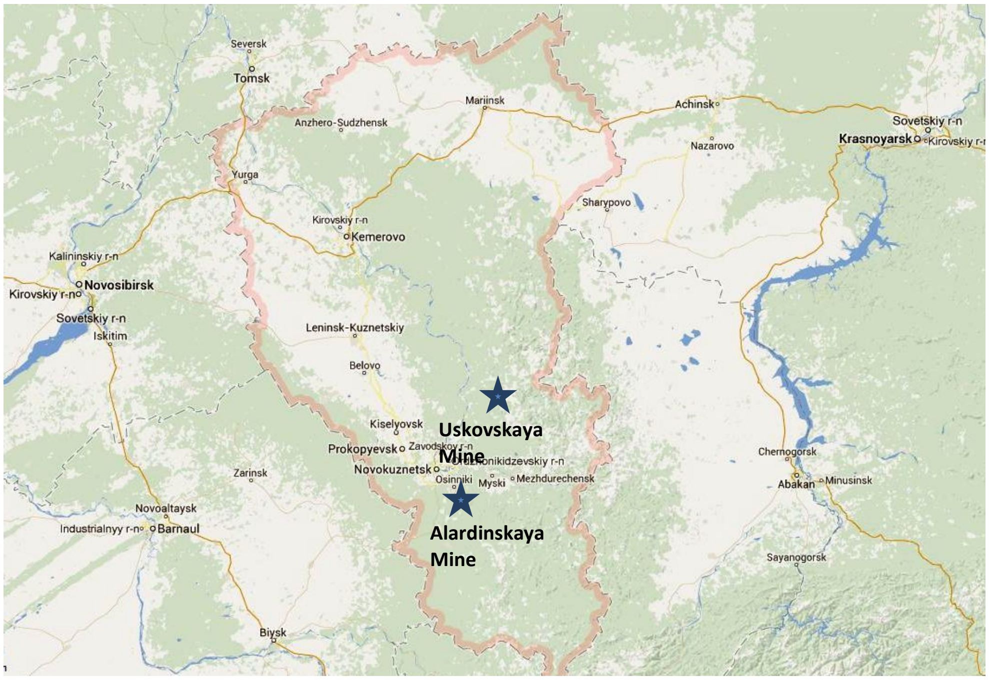
In 2012, as part of its commitment in support of the Global Methane Initiative (GMI), the U.S. Environmental Protection Agency's Coalbed Methane Outreach Program (CMOP) commissioned a pre-feasibility study to examine the potential for a coal mine methane (CMM) recovery and utilization project at a Russian coal mine. GMI is a voluntary, multilateral partnership that aims to reduce global methane emissions and to advance the abatement, recovery, and use of methane as a valuable clean energy source. GMI achieves its goals by creating an international network of partner governments, private sector members, development banks, universities, and non-governmental organizations in order to build capacity, develop strategies and markets, and remove barriers to project development for methane reduction, including CMM in Partner countries. More information about GMI and coal sector activities can be found at www.globalmethane.org.

Methane emissions from the Kuznetsk coal basin (Kuzbass) account for about 70% of total methane emissions from the entire coal mining sector of Russia and represent an attractive opportunity for CMM mitigation projects. Several mining groups operate in the Kuzbass, including Siberian Coal Energy Company (SUEK), which, in 2009, developed several CMM recovery and utilization projects at up to five coal mines and submitted the projects for registration under the UNFCCC Joint Implementation. Another mining group, Yuzhkuzbassugol United Coal Company, a division of the EVRAZ steel and mining group, is the eighth largest underground coal producer in Russia, producing approximately 11 million tons in 2012. Two of Yuzhkuzbassugol's eight coal mines operating in the Kuzbass—Alardinskaya and Uskovskaya coal mines—operate within the Kemerovo Oblast about 200 km apart, and both mine high-grade thermal and coking coal from carboniferous strata (**Figure 3**).

Alardinskaya is mining at about 700 m depth with two longwall shearing machines, and Uskovskaya is mining at about 300 m depth with a single longwall machine. Both mines are producing about two million metric tons (MMT) of coal per year, and have specific emissions of approximately 35 m^3 CH_4 per metric ton of coal mined. Mining started at the Alardinskaya and Uskovskaya mines in 1957 and 1966, respectively. They both operate degasification systems using central extraction pumps. Both mines are classified as "Super Hazardous," with CMM emissions greater than 15 m^3/t. A major mine explosion (caused by methane gas) occurred at Uskovskaya in May 2007 and the Alardinskaya was evacuated in March 2013 due to fire.

The Alardinskaya and Uskovskaya coal mines were selected for a pre-feasibility study due to their favorable characteristics and operations, and because most of the drainage gas produced is higher in methane than at other Yuzhkuzbassugol mines.

Figure 3. Mine locations in the Kemerovo Oblast



4.0 Russian Natural Gas and Power Market Information

4.1 Natural Gas Market

Russia has the largest reserves of natural gas in the world—at 1,680 trillion cubic feet—and produced 23 trillion cubic feet in 2010.[4] Sixty percent of produced gas is sold domestically to households and industry at or below long-term marginal costs. There is considerable disparity between the price received from exported gas and that received from domestic consumption. A strategy was promoted in 2006 to reach price parity with exports by 2011; however, this has not happened due to the rapid rise of oil prices which most export gas price contracts are tied. The current gas price is 3,771 Russian rubles (RUB) /m^3 or \$4.00/Mcf (exchange rate of 33.28 RUB/U.S. dollar). Enriching this gas for even low-Btu applications would exceed the price of high-quality natural gas available in the region; therefore, gas sale was eliminated from further consideration for this study.

4.2 Power Market

The power generation sources in Russia are shown in **Table 1** using data from the International Energy Agency.[5]

Table 1. Emission factors and power generation by source

Power Source	tCO_2/MWhr	Billion kWhr	%	Weighted EF
Coal	0.943	164,348	15.6%	0.147
Oil	0.821	27,362	2.6%	0.021
Gas	0.553	519,202	49.4%	0.273
Bio	0.000	35	0.0%	0.000
Nuclear	0.000	172,941	16.4%	0.000
Hydro	0.000	167,608	15.9%	0.000
Geothermal	0.000	522	0.0%	0.000
Solar PV	0.000	0	0.0%	0.000
Solar Thermal	0.000	0	0.0%	0.000
Wind	0.000	5	0.0%	0.000
Total		**1,052,023**	**100%**	**0.442**

Because 32% of power is generated by non-CO_2 emitting technologies, and almost half is generated by natural gas, the aggregated emission factor is somewhat less than for pure methane.

Domestic power prices have doubled over the past 10 years and now appear to be in line with global power prices. Both mines reported paying \$68/megawatt-hour (MWhr) for power. This price is comprised of a demand charge based on registered power consuming systems (installed capacity) and a consumption charge based on actual usage. Installing a power generating system independent of the grid will effectively reduce the installed consumption capacity as well as grid power consumption,

[4] http://www.eia.gov/cfapps/ipdbproject/IEDIndex3.cfm?tid=3&pid=26&aid=1

[5] http://www.iea.org/statistics/statisticssearch/report/?&country=RUSSIA&year=2011&product=ElectricityandHeat

realizing a savings of \$68/MWhr. **Figure 4** shows a power price forecast from the Russian Energy Forecasting Agency, initiated in 2008,[6] when the price was 1,355 rubles/MWhr or \$41/MWhr (33.28 RUB/U.S. dollar). The power price in 2013 was expected to be \$89/MWhr by 2013 with inflation or \$62/MWhr without inflation (i.e., prices are trending upward). No information on price volatility or regional variation could be found at the time of the study.

Figure 4. Forecast of electricity tariffs in Russia

[6] http://www.academia.edu/2204254/Electricity_Markets_in_Russia_english_updated_

5.0 Alardinskaya CMM Project Evaluation

5.1 Summary of Mine Characteristics

The coal measures in the Alardinskaya mine area are approximately 600 m thick and contain approximately 60 m of coal within 38 coal seams. The coal is Carboniferous in age and is low-ash (16% to 19%), low-sulfur (0.04% to 0.4%), high-heat-content (8,600 kcal/kg) coking and thermal coal. **Figure 5** is a geologic cross-section of the coal measures showing the seams of interest.

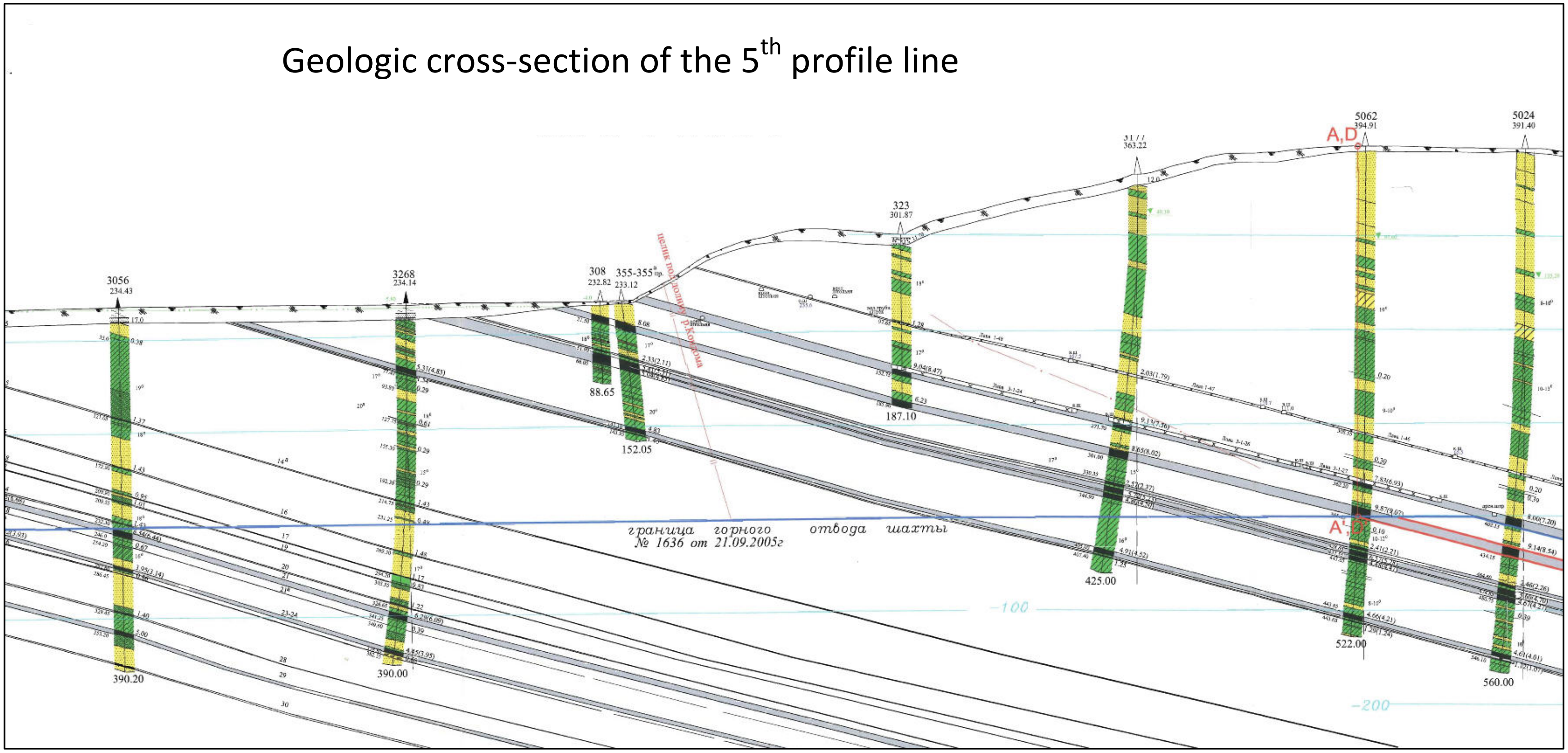
Table 2 shows some of the characteristics of the coal seams currently mined.

Table 2. Mined seams in the Alardinskaya mine area

Seam	Grade	Seam Thickness, m			Coal Density, t/m^3	Bulk Density, t/m^3	Reserves, Thousand Tonnes	Commercial, Thousand Tonnes
		From	Up to	Avg.				
6	КС.	6.8	10	8.5	1.36	1.4	29,960	22,782
3a	КС.	5.3	8.3	6.8	1.39	1.4	58,365	35,081

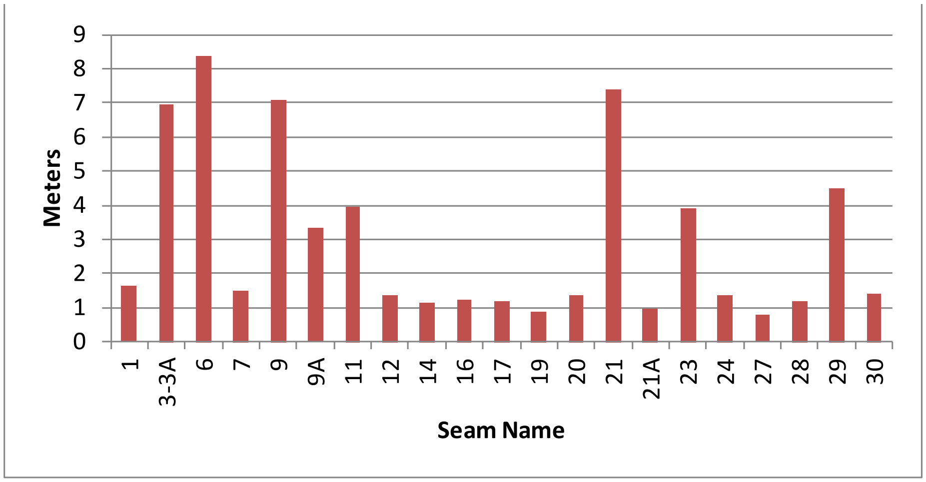
Mining started at the Alardinskaya mine in 1957.

Figure 5. Coal measures of the Alardinskaya mine area



The strata dip from 14 to 20 degrees. The average seam thickness is shown in **Figure 6** by seam name. Two longwall panels are being mined, one in seam 3a and one in seam 6. The longwall machines can mine up to 5 m in height; the remaining coal is left in the mine floor. Currently, about 65% of the coal production is from the 3a seam. As mining continues, deeper, gassier coal will be developed, especially in seam 6.

Figure 6. Coal seam thickness by name in stratigraphic order from top to bottom



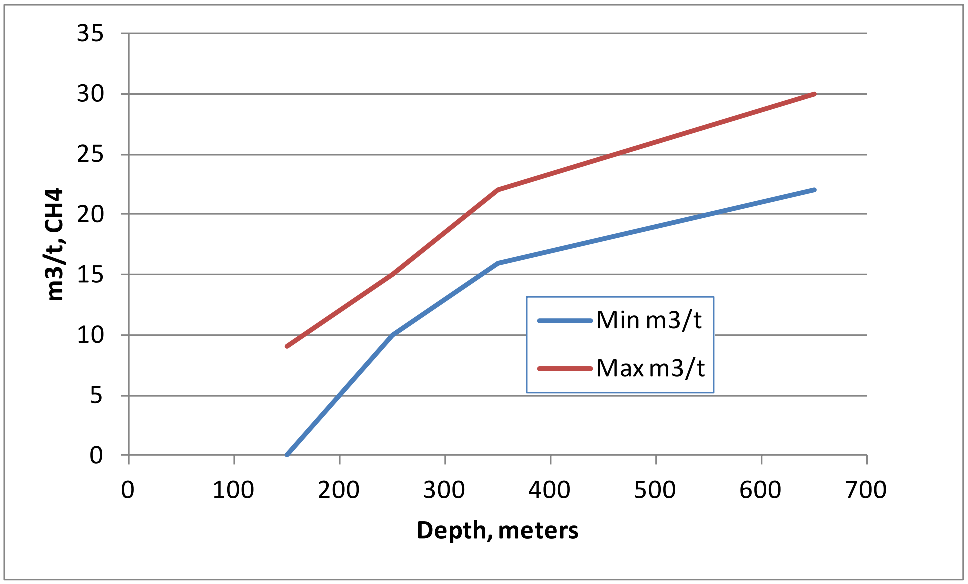
5.2 Gas Resources

Table 3 and **Figure 7** show the increase in gas content associated with depth. Mining in the 3a seam occurs at depths from 152 m to 400 m, so very high gas contents exist in the mined coals and nearby seams.

Table 3. Methane content of coal in the Alardinskaya region

Depth, m	Min m^3/t	Max m^3/t
150	0	9
250	10	15
350	16	22
650	22	30

Figure 7. Range of methane content of seam 3a by depth



Annual emissions data are presented in **Table 4.** The percent degas column is the percentage of total emissions from the degasification system. The last column (specific emissions) is based on the average production rate from 2007 through 2011 of 2.763 MMT of coal per year.

Table 4. Annual average emission numbers for Alardinskaya mine

Year	$m^3/min\ CH_4$				% Degas	Specific Emissions, m^3/t
	VAM	Degas	Bleeder	Total		
2011	82.91	37.3	32.6	152.8	24.4%	29.1
2010	93.1	14.7	65.1	172.9	8.5%	32.9
2009	86.6	15.0	69.7	171.3	8.8%	32.6
2008	113.4	23.8	80.5	217.6	10.9%	41.4
2007	96.7	26.3	75.8	198.8	13.2%	37.8

5.2.1 Ventilation Air System

There are three ventilation fans: two positive pressure, one negative pressure. Their air rates are shown in **Table 5**. The 2BII-15 fan is on the gob bleeder shaft that runs from 0.75% to 1.5% methane.

Table 5. Alardinskaya ventilation fans

Air Rate, m^3/min			
Fan	Min.	Max.	Avg.
TAF 45	18,000	23,050	22,550
6BII-15	6,500	11,200	8,600
2BII-15	3,100	3,100	3,100

5.2.2 Pre-Mining Gas Drainage System

The in-mine drainage wells are networked together with a piping system and the gas transported to two pre-mine gas pumping stations: PGM-Lennetal and MDU 195RB (4 RB-DV105). The PGM-Lennetal pump station is about 1,500 m from the main ventilation fan site, and the MDU 195RB (4 RB-DV105) pump station is 4,120 m from the main fan site. **Table 6** shows the total gas rates for the two pumping stations.

The MDU 195RB (4 RB-DV105) pump is a water ring pump that applies a very high suction pressure. It is believed that mine air is entering the pipe at the in-mine methane drainage boreholes and diluting the gas to the low values shown in **Table 7**. The PGM-Lennetal pump is a standard dry pump and is set up as a methane extraction system with inlet methane concentration control. It uses a methane concentration sensor and speeds up or slows down the pump on a proportional, integral, and derivative hysteresis loop to ensure that a target of greater than 25% methane is achieved. The system also initiates pump startup and shutdown, and controls a recirculation valve for fine concentration and suction control. This system manages suction and prevents over-draining.

Both pump stations drain gas from a series of boreholes drilled into the developed longwall panels approximately six months before mining the panel. The mine employs three drilling teams of four persons each, with each team operating two drilling rigs. A typical face has 250 to 325 holes per face (76 millimeters in diameter), with each hole measuring 200 m in length. The current system is diagrammed in **Figure 8** and **Figure 9**. **Figure 8** shows the PGM-Lennetal pump station drainage system. Two panels are drained, one in seam 3a and one in seam 6. Currently, boreholes are drilled only into the seam(s) to be mined and no cross-measure boreholes are used for post-mine gob drainage. **Figure 9** shows the MDU 195RB (4 RB-DV105) pump station drainage system, which drains one panel in seam 6.

Table 6. Alardinskaya pump station rates

Total Gas, m^3/min			
Pump Station	**Min.**	**Max.**	**Avg.**
PGM-Lennetal	33	70	45
MDU 195RB (4 RB-DV105)	30	60	43
Total	**70**	**103**	**84**

Table 7. Alardinskaya pump station methane

$\%CH_4$			
Pump Station	**Min.**	**Max.**	**Avg.**
PGM-Lennetal	32	46	40
MDU 195RB (4 RB-DV105)	2.75	3.14	3

Figure 8. PGM-Lennetal pump station drainage system

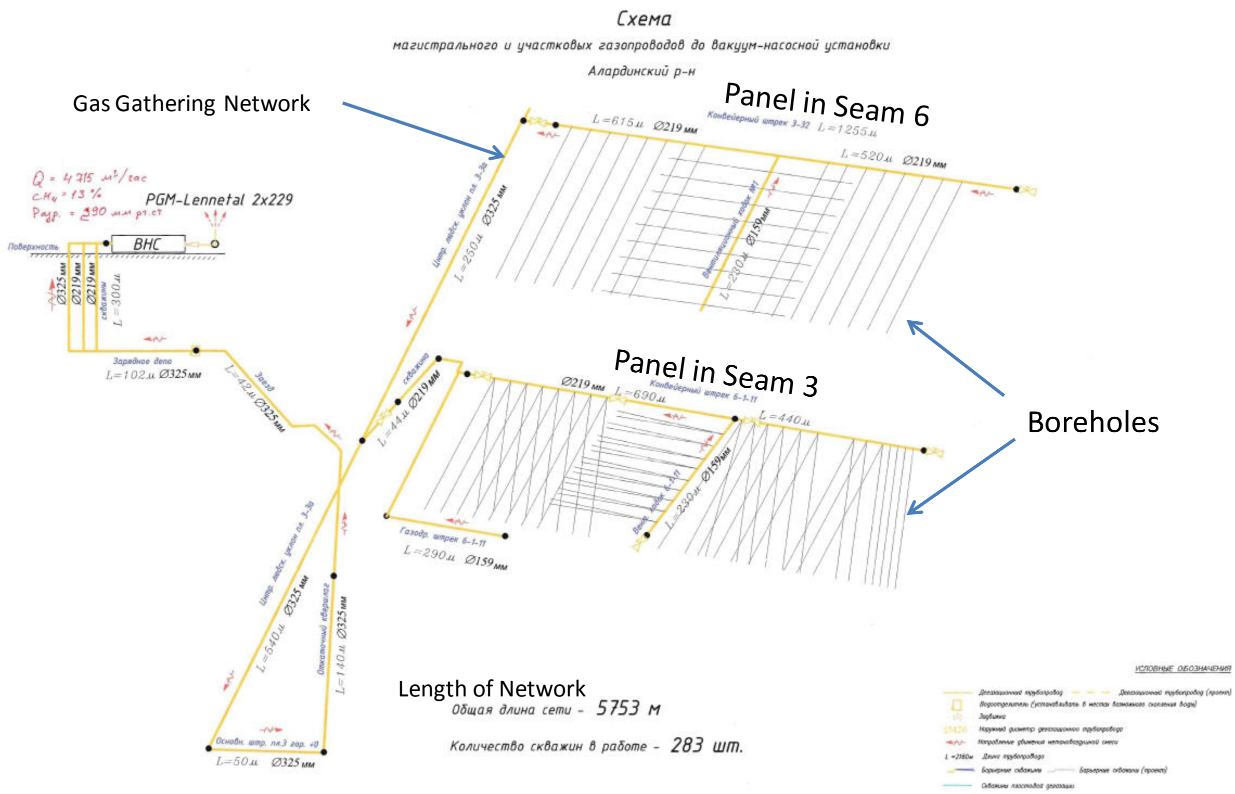
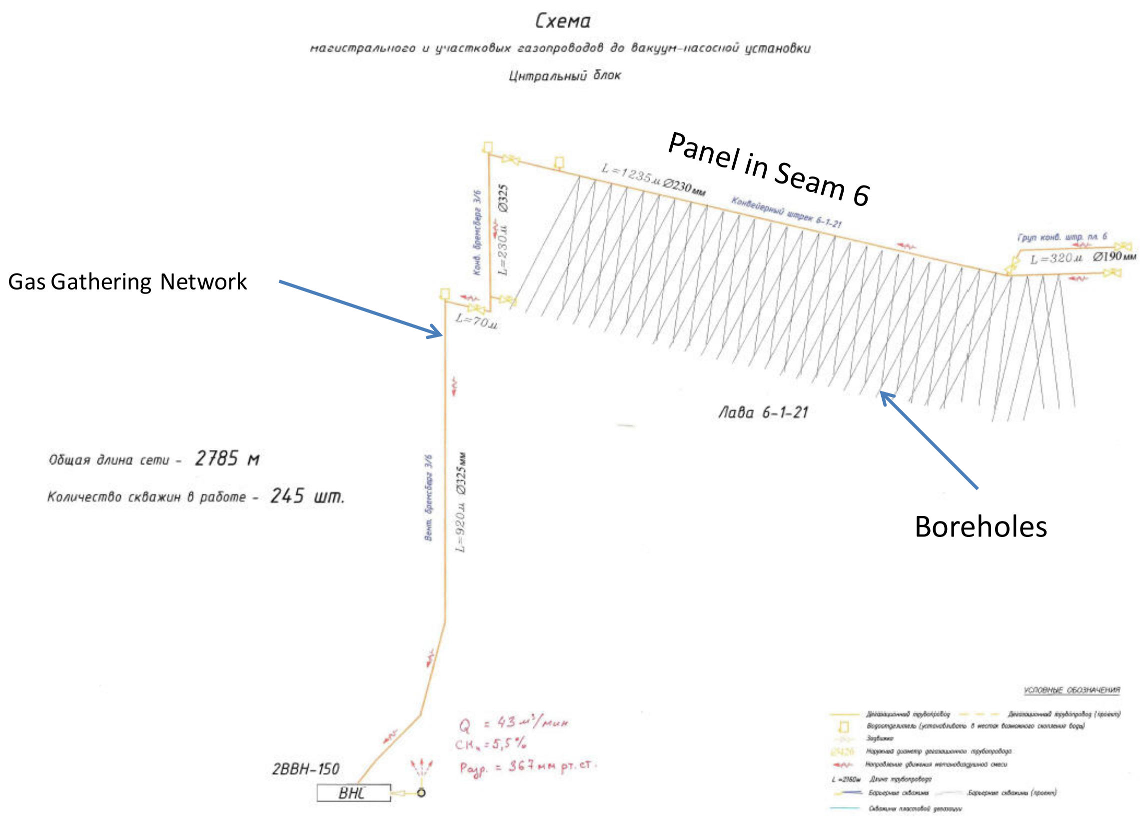


Figure 9. MDU 195RB (4 RB-DV105) pump station drainage system



5.3 Technical Possibilities for CMM Usage

The study analyzed and determined that using drainage gas at the PGM-Lennetal drainage station and heat from VAM destruction at the bleeder shaft may be technically and economically feasible. The MDU 195RB (4 RB-DV105) station was not considered due to its consistently low methane content (i.e., less than 5%). As noted earlier in the natural gas market section, pipeline injection of the drainage gas is not feasible because of the very low price of natural gas in Russia. Summarized below are the two most feasible options considered for the PGM-Lennetal drainage station: 1) power generation and 2) heat generation using VAM.

5.3.1 CMM Option 1: Power Generation Using Drainage Gas

The PGM-Lennetal pump station provides a fairly stable gas rate and methane concentration, and can support a 3-MWe power project. However, as shown in **Table 6** and **Table 7**, there is some uncertainty in the volume and methane concentration produced at the pump station. The cumulative probability distributions shown in **Figure 10** and **Figure 11** were generated using the low, average, and high values as end points in a triangular configuration. **Figure 10** shows a 90% probability that the total gas rate will be between 29.2 m^3/min and 74.9 m^3/min. **Figure 11** shows a 90% probability that the methane concentration will be within 30.6% and 47.4%.

Figure 10. Cumulative probability distribution of the total gas rate from PGM-Lennetal

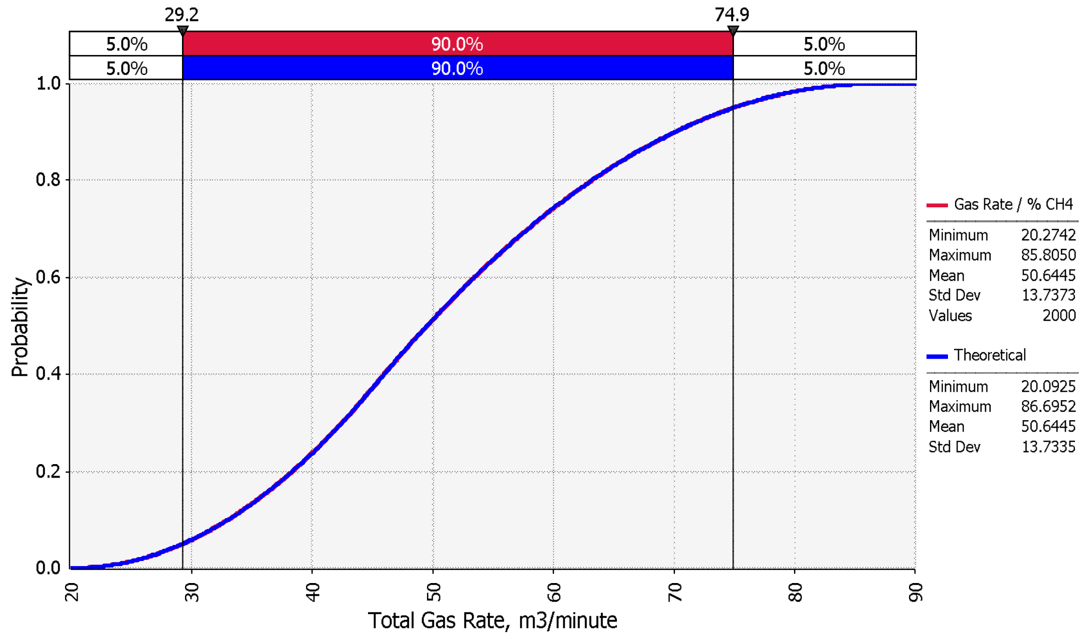
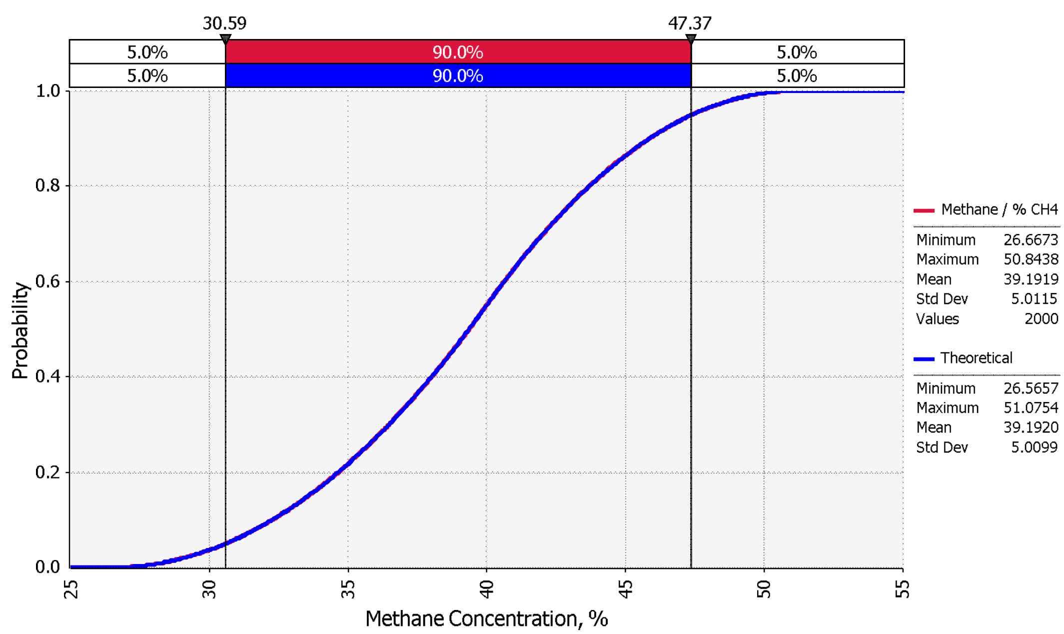
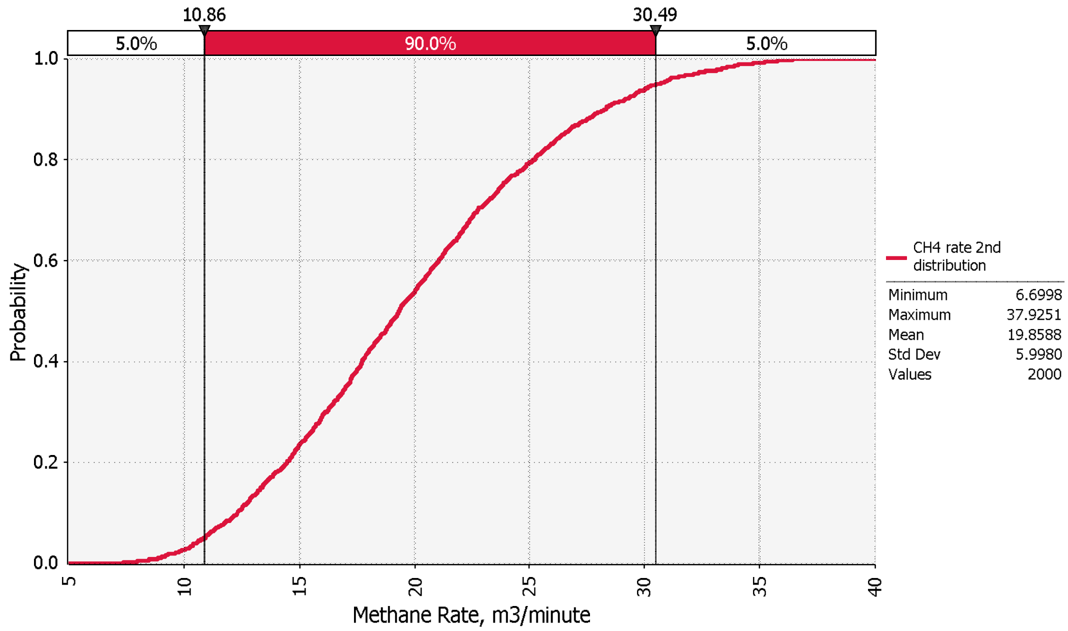


Figure 11. Cumulative probability distribution of the methane concentration at PGM-Lennetal



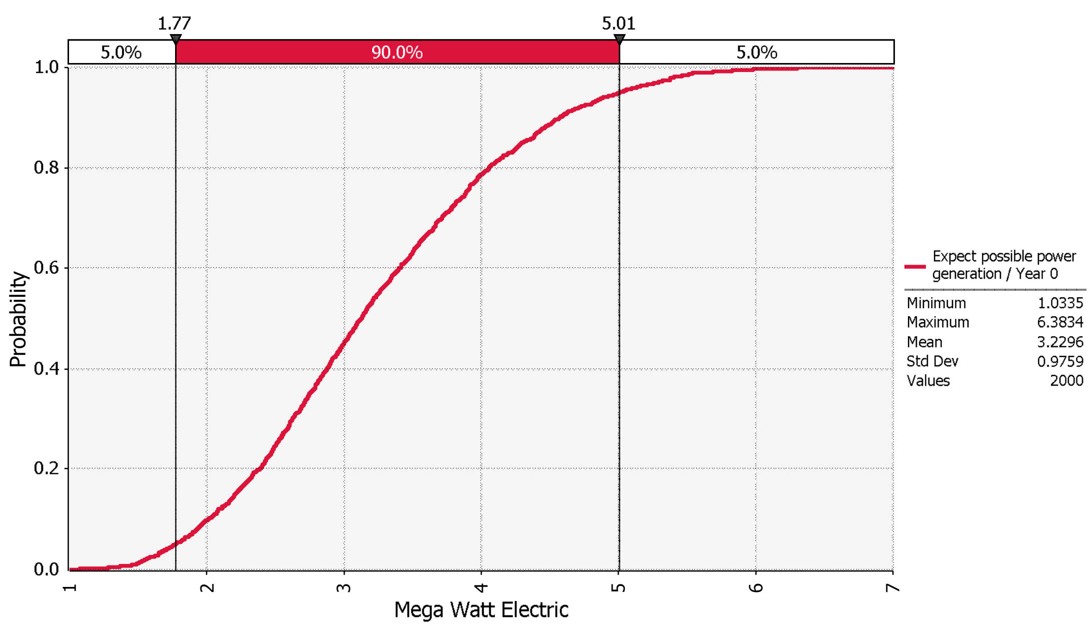
Combining these two probability functions through Monte Carlo simulation produces the cumulative probability distribution of methane flow rate shown in **Figure 12**.

Figure 12. Cumulative probability distribution of methane flow rate from PGM-Lennetal



This distribution, converted to annual volumes, was used to determine the potential power production from the PGM-Lennetal pump station. This probability distribution is shown in **Figure 13**.

Figure 13. Cumulative probability distribution of power generation capacity at PGM-Lennetal, MWe



These data were generated after assuming that gas over 25% methane will be delivered to the gensets 64% of the time (on a 24/7 basis). This is a conservative value, but run time data on the station were not available at the time of this study.

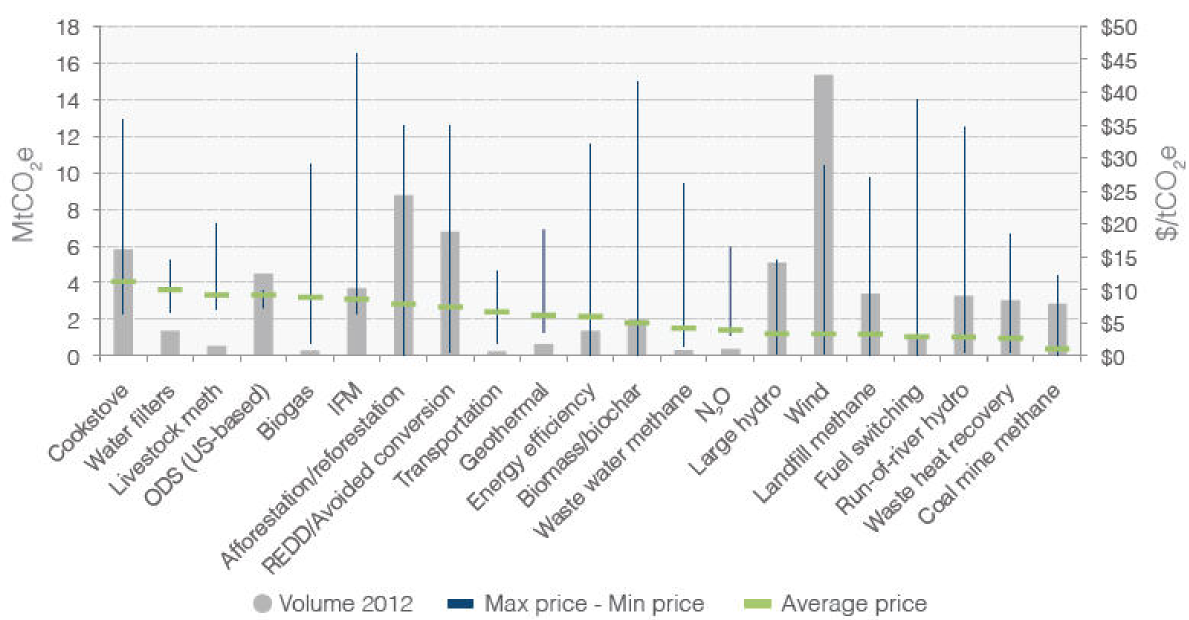
Gensets evaluated for this study comprised 1.48 MWe units running at 43% electrical efficiency. The results of the analysis support the installation of two gensets without overbuilding the power station (i.e., about a 60% chance of being able to consistently supply a 2.96 MWe station or larger).

With two units running 90% of the time, 77,000 tCO_2e/year would be destroyed and the power produced would offset grid power by another 10,000 tCO_2e/year. Subtracting the CO_2 generated by the project (i.e., 10,000 tCO_2e/year) would result in net emission reductions of 77,000 tCO_2e/year over a 10-year project life.

5.3.1.1 Power Generation Project Economic Analysis

This pro forma economic analysis will be based on power generation using the reported cost of power for the mines ($68/MWhr) with no inflation or real price escalation. A carbon price of $1.00/$tCO_2e$ is used based on **Figure 14**, which shows the prices paid in over-the-counter transaction in the voluntary carbon market based on project type. Note that CMM is at the far right with an apparent average price of approximately $1.00/$tCO_2e$. Because the future of carbon prices are uncertain, a conservative price of carbon and power sales price were used that could produce a 25% rate of return.

Figure 14. Volume and prices paid for voluntary carbon offsets in 2012[7]



Notes: Findings based on 77 $MtCO_2e$ associated with transaction-level price, volume, and project type.
Source: Forest Trends' Ecosystem Marketplace. *State of the Voluntary Carbon Markets 2013.*

[7] "State of the Voluntary Carbon Market." *Bloomberg New Energy Finance*. http://about.bnef.com/white-papers/state-of-the-voluntary-carbon-markets-2013/.

5.3.1.2 Project Costs

Power generation using two 1.48-MWe units was used in the economic analysis. Project costs to install and operate a power generation station are shown in **Table 8,** with the stated cost being the mean value and the minimum and maximum costs being +/- 20% of the mean.[8]

Table 8. Capital and operating costs for power generation

Parameter	Min	Mean	Max	5%	95%
Capital expenditure for power plants (M$/MW)	0.53	0.82	1.11	0.62	1.02
Operating costs ($/MWhr)	13.19	16.00	18.80	14.01	17.97

Values for other parameters used in the pro forma economic analysis are shown in **Table 9**.

Table 9. Values for other parameters used in pro forma economic analysis

Assumptions	Value
Emission reduction factor (tCO_2e/m^3 CH_4)	0.01407
Emission reduction factor net of CO_2 produced (tCO_2e/m^3 CH_4)	0.01223
Methane density ($tonne/m^3$)	0.000667
Methane CO_2 emission factor (tCO_2/tCH_4)	2.75
Energy content of pure methane (MJ/m^3)	35.55
IC engine electrical conversion efficiency	43%
Methane drained delivered as fuel to generators (>25%)	64%
Percent generators online	90%
Power transmission to substation (M$)	$0.437
Carbon dioxide emission factor grid power ($tCO_2e/MWhr$)	0.442
CO_2 emission factor for anthracite ($tCO_2e/tonne$)	2.57
Heat required? (yes/no)	no
Partner share of power sales	100%
Partner share of Certified Emission Reduction sales	100%
Genset installation increment, MW	1.48
Build factor	1.30

5.3.1.3 Cash Flow Analysis

The results of the economic analysis are shown with and without verified emission reductions (VERs) or a similar carbon price mechanism. **Figure 15** shows the IRR, while **Figure 16** shows 10% net present value (NPV). The mean IRR without VERs was 7.6% but increased to 12% with revenue from just $1.00/$tCO_2e$. While the economic analysis used the currently conservative VER price of $1.00/$tCO_2e$, it may be possible to achieve a $2.00 to $5.00/$tCO_2e$ price with international buyers in limited bilateral agreements.

[8] Taken from a proprietary estimate of costs.

Figure 15. IRR for the power generation project with and without carbon price

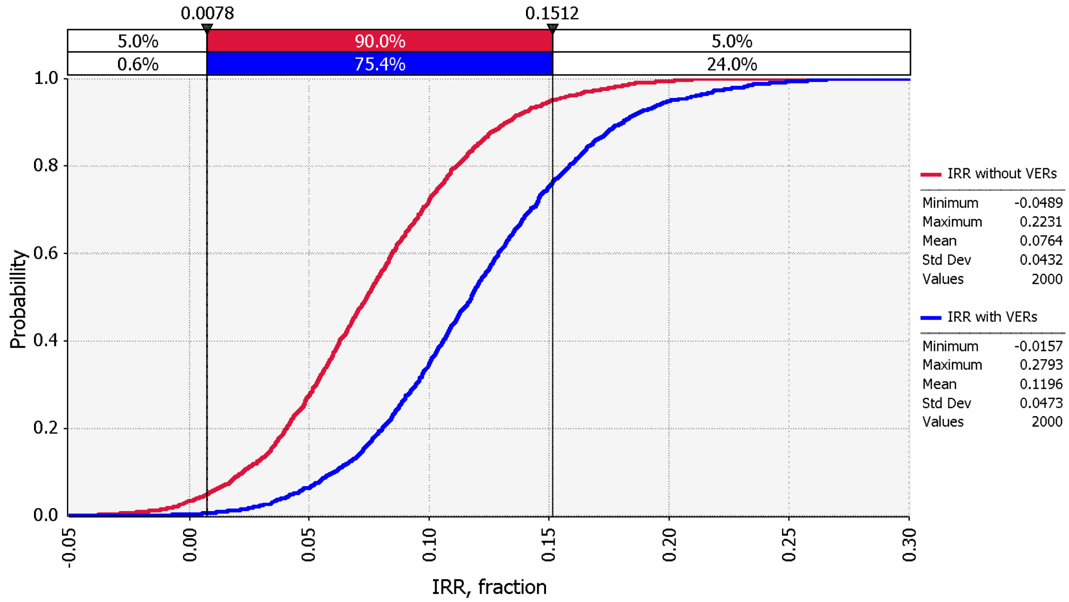


Figure 16. 10% discounted NPV for the power generation project

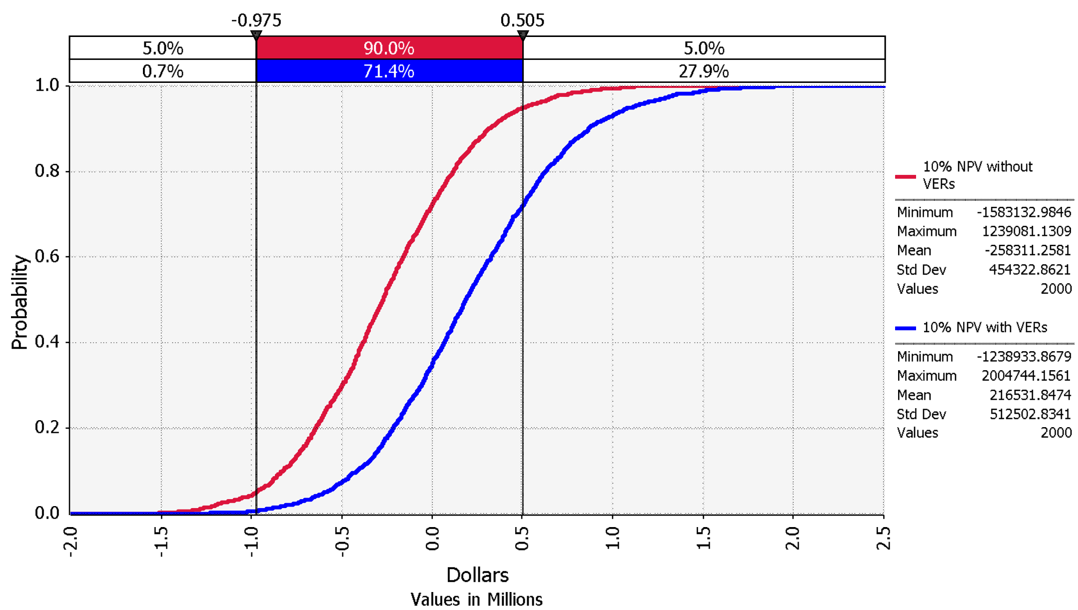


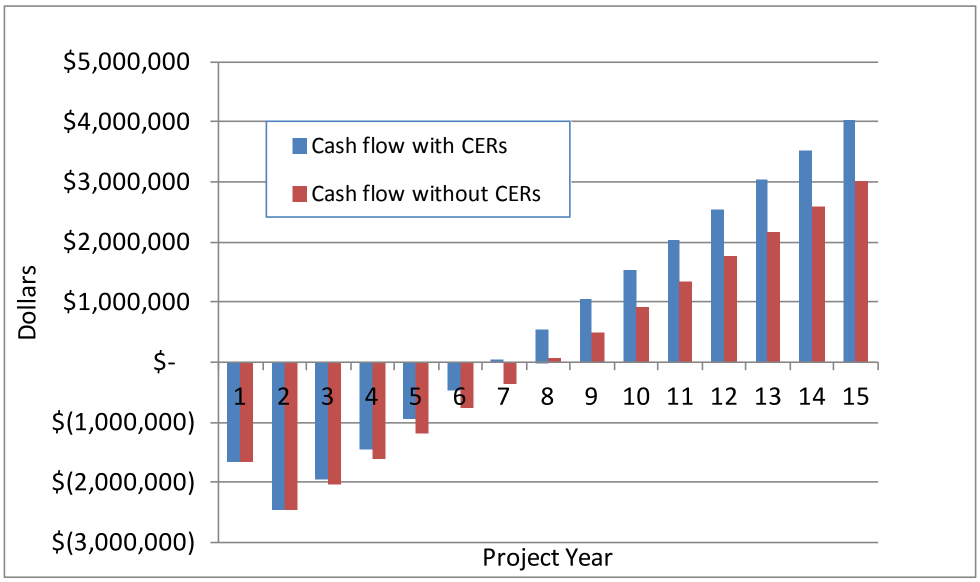
Table 10 shows the NPV at various discount factors with and without the VERs valued at \$1.00/tCO_2e at 77,000 tCO_2e/year.

Table 10. Average economic parameters with and without carbon price

	With VERs	Without VERs
NPV @ 10%	$212,665	($157,081)
NPV @ 15%	($239,470)	($519,759)
NPV @ 20%	($533,241)	($750,705)
IRR	12.1%	8.4%

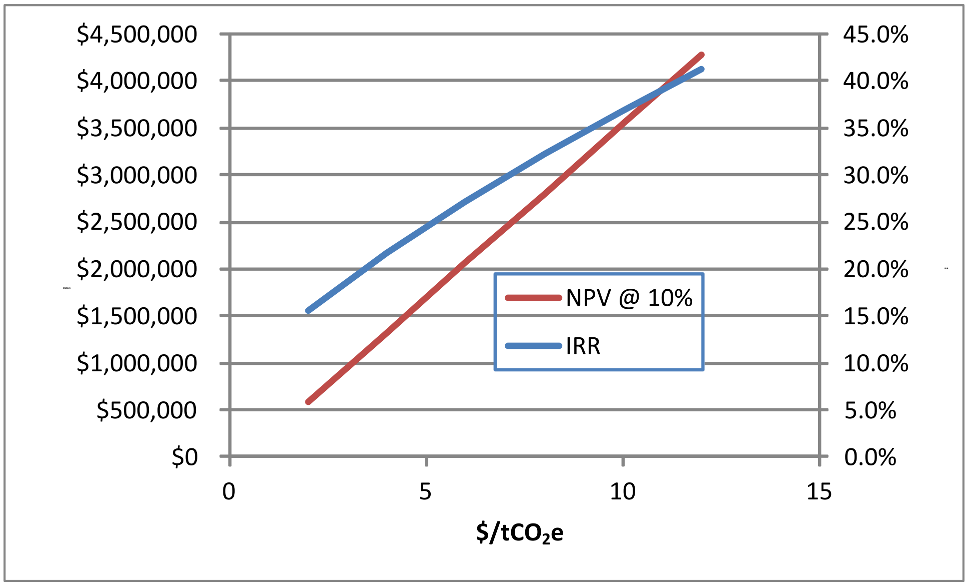
Figure 17 shows the undiscounted cumulative cash flow for the two cases. The case without VERs paid back the investment in about eight years, while the $1.00/tCO$_2$e case paid back within seven years.

Figure 17. Cumulative undiscounted cash flow for Alardinskaya power project



Even a modest increase in the price for emission reduction credits plays a significant role in making the project economically attractive. **Figure 18** shows the relationship of NPV and IRR to a carbon price. For example, a carbon price of **$5.20/tCO$_2$e would provide a 25% IRR**.

Figure 18. NPV at 10% discount rate and IRR as functions of carbon price



5.3.2 CMM Option 2: VAM Destruction for Greenhouse Gas Mitigation

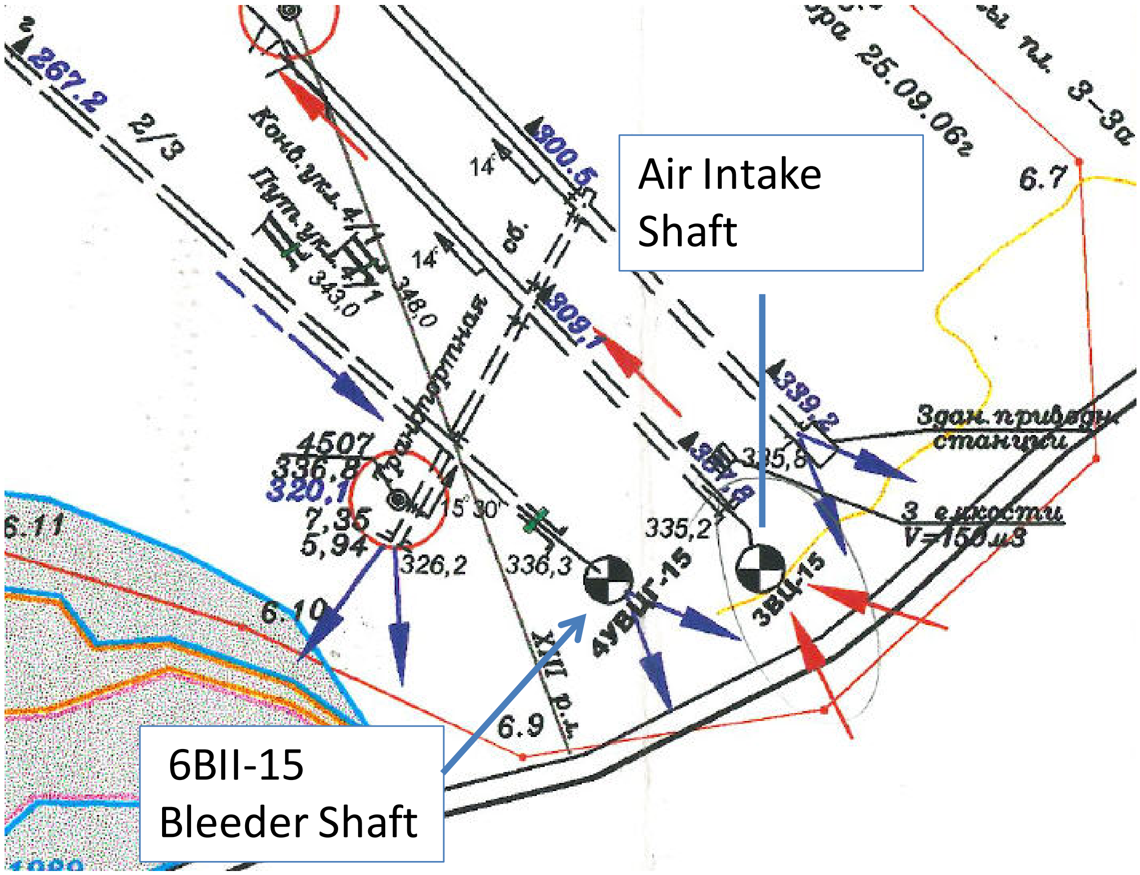
There are three ventilation fans: two positive pressure, one negative pressure. Their air rates are shown in **Table 11.** The 2BII-15 fan is installed on the gob bleeder shaft that runs from 0.75% to 1.5% methane.

Table 11. Alardinskaya ventilation fans

Air Rate, m^3/min			
Fan	**Min.**	**Max.**	**Avg.**
TAF 45	18,000	23,050	22,550
6BII-15	6,500	11,200	8,600
2BII-15	3,100	3,100	3,100

Figure 19 shows the relative locations of the 6BII-15 positive pressure fan and the 2BII-15 negative pressure fan on the gob drainage bleeder shaft.

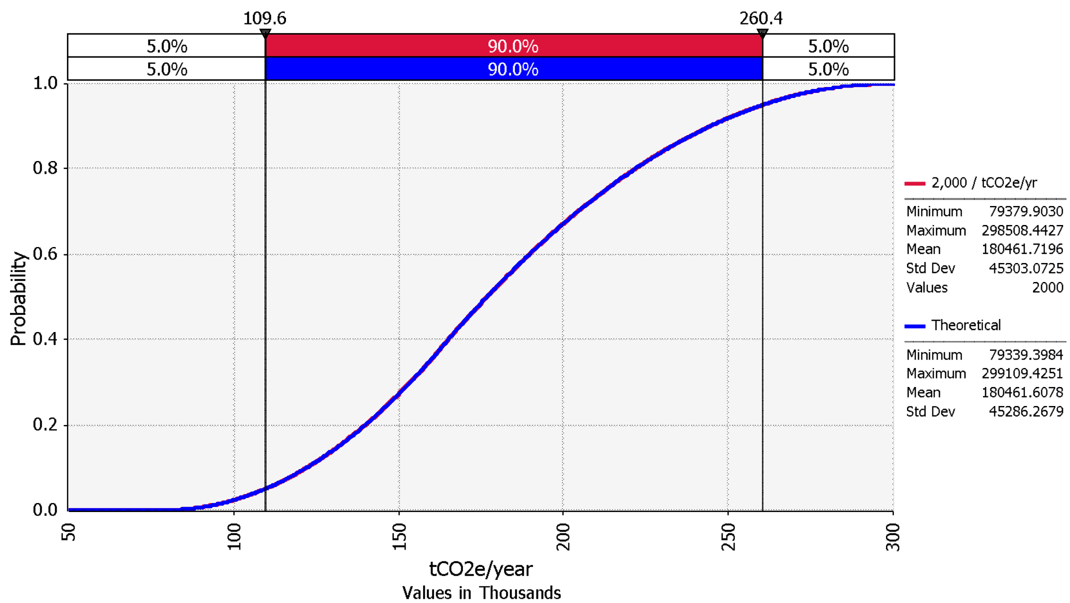
Figure 19. Intake and exhaust (bleeder) fans in the southeast area of Alardinskaya



In order to justify the installation of VAM destruction devices, it will be necessary to have a suitable price on the emission reductions.[9] This value would be considerable, as shown in **Figure 20,** where between 109,000 and 260,000 tCO_2e/year could be destroyed at a 90% probability (based on available information).

[9] Pro forma evaluation assumes future incentive(s) will be available for these reductions (i.e., as the coal industry comes under increasing pressure to reduce GHG emissions, methane capture represents a lower cost options than alternatives such as Carbon Capture and Storage).

Figure 20. Cumulative probability distribution for emission reductions from the bleeder shaft



CMOP's Coal Mine Methane Project Cash Flow Model was used to investigate the carbon price that would enable a profitable project based on the program inputs shown in **Table 12**.

Table 12. Parameters used to calculate pro forma economic analysis

Percent methane in the ventilation air	1	%
Recoverable ventilation air flow	105	Mcf/min
Planned project operational lifetime	10	years
Carbon credit unit sale price	1.00	$\$/tCO_2e$
Installed capital cost of the VAM oxidation system	22	$/cfm
Annual operating and maintenance of the VAM system	1.3	$/cfm-year
Electrical load of the oxidizer blowers	0.075	kWh/Mcf
Cost of electric power used by the project	68	$/MWhr
Inflation rate	2.5	%
Real discount rate	10	%
Royalty, severance tax, and negotiation fees	0	%
Contingency factor	5	%
Hours per year the VAM system will operate	8,000	hrs/year
Annual escalation rate for carbon credits	5	%

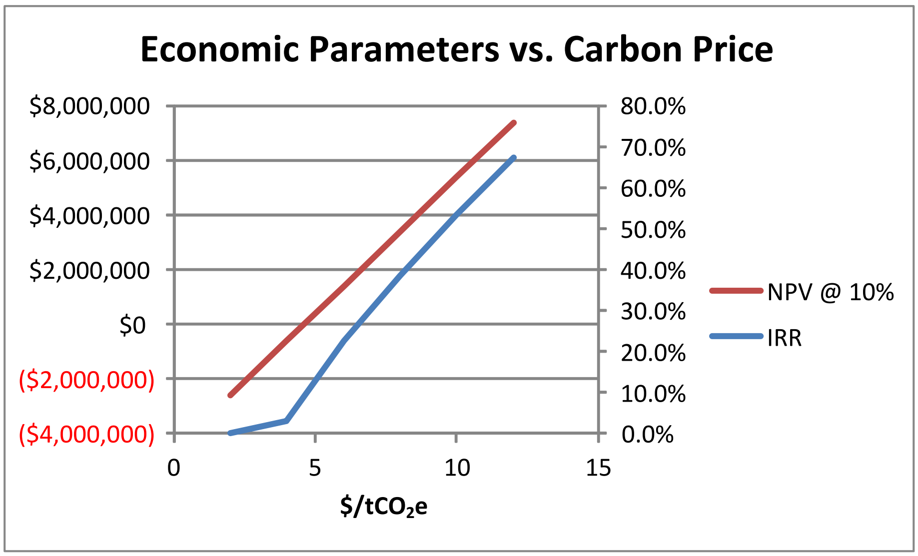
Table 13 shows the results of this pro forma economic analysis.

Table 13. Results of pro forma economic analysis

Total capital cost ($)	2,426,000
Total annual cost ($/year)	394,000
Carbon credits earned annually (tonnes/year)	166,066
Internal rate of return (%)	0
Net present value ($)	-2,991,000

The carbon price of $1.00/tCO_2e$ has a zero rate of return. The goal seek function of the program was used to determine the carbon price (i.e., $5.21/tCO_2e$) necessary to provide a 25% IRR. Figure 21 shows the relationship of NPV and IRR to carbon price. This VAM economic analysis shows better-than-average performance for VAM projects relative to carbon price because of the richness of the VAM from the bleeder shaft (evaluated at 1%).

Figure 21. NPV at 10% discount rate and IRR as functions of carbon price



5.4 Options for Increasing Methane Drainage

Figure 22 shows a zoomed-in portion of the geologic cross-section for the Alardinskaya area. This view diagrams the longwall panel in seam 3a (panel 3-1-26). Because the seam is too thick for the longwall machine to mine, a significant amount of coal is left in the panel's floor. This floor coal potentially releases significant amounts of gas into the gob area after the panel has been mined; further investigation by the mine owner is recommended. Also, seam 6 is within 30 m of seam 3a and could also release gas into the gob. The scope of this study did not allow for verification; the mine operators should verify the gas amount(s) through targeted drilling within the mine.

Because seam 6 is very gassy, it might prove advantageous to drill pre-mine boreholes from seam 3a (before mining the panel) into seam 6. That way, when coal is removed from seam 3a, gas can be captured from seam 6 via boreholes before making its way up into the gob area of seam 3a and also reduce the methane content of seam 6 prior to mining. The coal in seam 6 will be much more permeable because of the heaving and fracturing related to seam 3a coal removal. **Figure 23** shows a diagram of this concept. The same approach can be used to help control gas emissions from seams 7 through 9, which underlie seam 6 by approximately 30 meters (see **Figure 22**). This would also degas the lower seams, reducing the emissions into the working areas of these seams if they are to be mined in the future.

Figure 22. Panel 3-1-26; almost half of total coal thickness is left in the floor

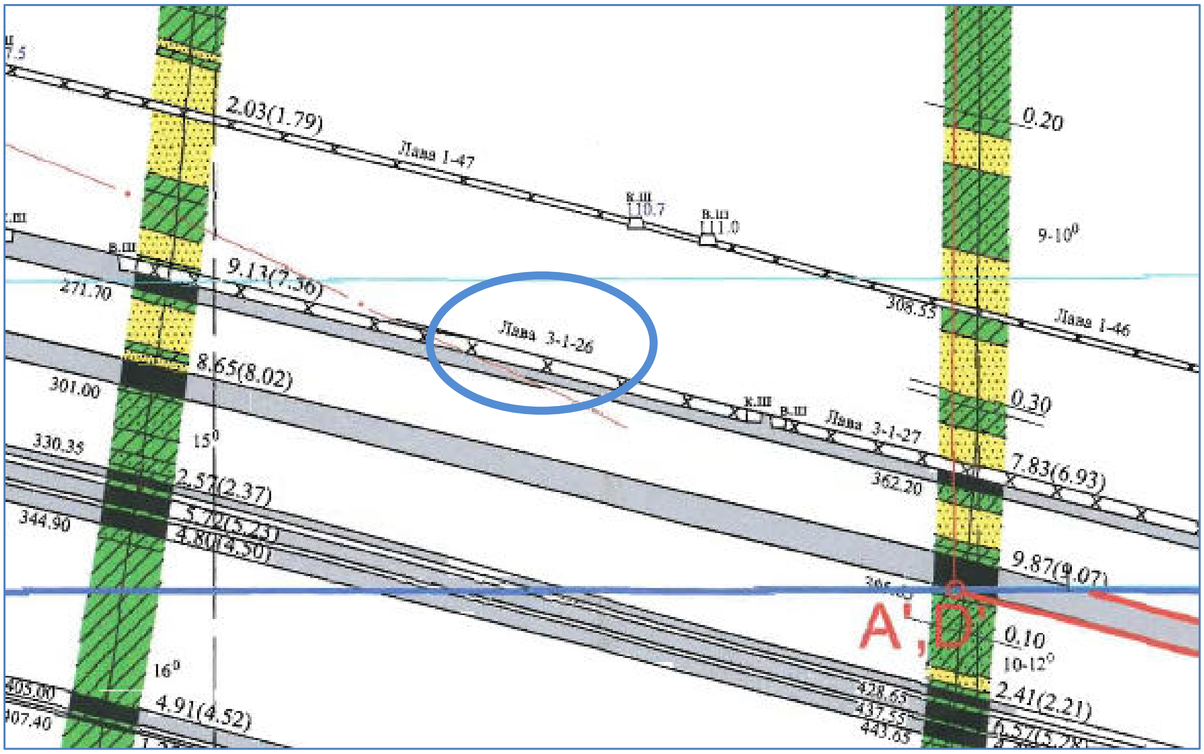
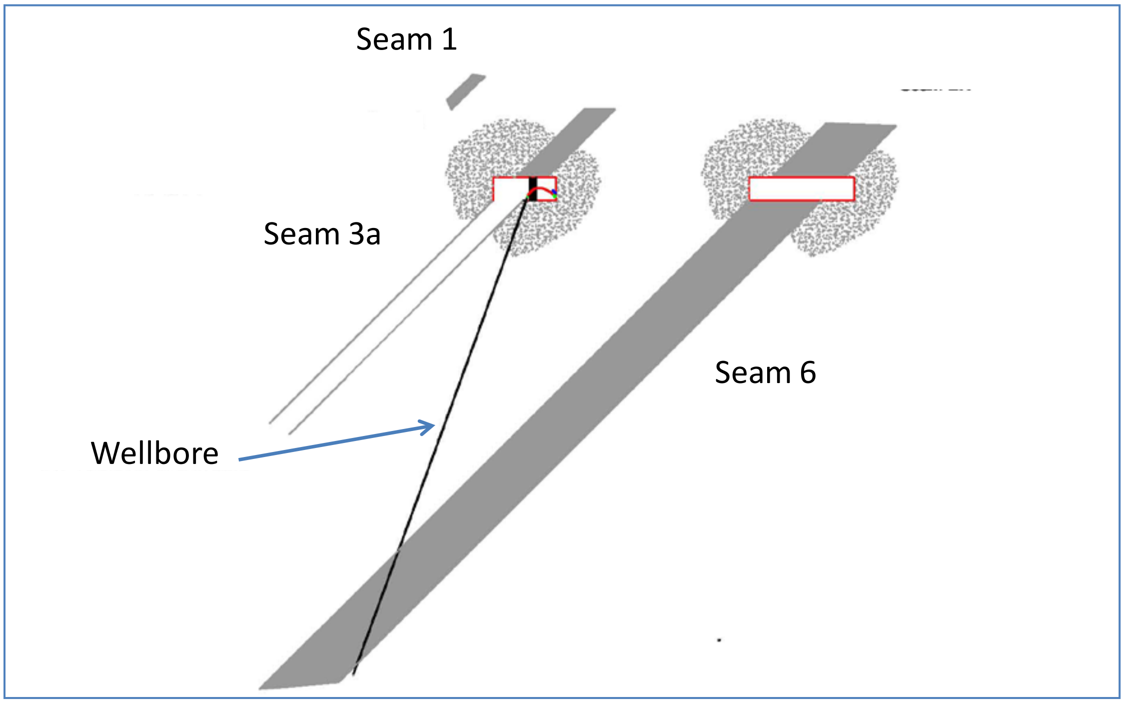


Figure 23. Pre-draining a lower seam while mining the upper seam to reduce methane migration to the gob of the upper seam



5.5 Observations and Recommendations

Below are some initial observations based on review of the data, along with recommendations for further investigations at the Alardinskaya mine.

5.5.1 Observations

- There is considerable uncertainty in the range of methane content at the bleeder shaft, as well as at the PGM-Lennetal pumping station. The high frequency variability of these parameters can significantly affect the performance of any project that might be proposed.
- The study relied on the data reported for 2010 at the PGM-Lennetal pumping station for the low, mid-, and high volumes and methane content in order to conclude that a power generation project could produce 3 MWs. 2010 is the year of lowest degas volume as reported in **Table 4** (14.7 m^3/min CH_4). The following year reported more than double that volume (37.3 m^3/min CH_4). If the 2011 value remains consistent, the project could be significantly larger (assuming adequate gas quality).
- Because the seam is too thick for the longwall machine to mine, a significant amount of coal is left in the panel's floor. This floor coal potentially releases significant amounts of gas into the gob area after the panel has been mined. Also, seam 6 is within 30 m of seam 3a and could also release gas into the gob.

5.5.2 Recommendations

- A more robust electronic data collection effort from the bleeder shaft and PGM-Lennetal pumping station would enable a much better defined analysis of methane content (data is currently recorded manually in notebooks). Daily sampling from these locations for at least a month would provide better definition of the variability of the methane concentration and flow rate.
- Experimentation with drilling into the seams below the actively mined panel before mining might degas the seam to some extent, and result in increasing gas into the gob area, and significantly degas the seam rapidly after the panel has been mined and the floor has heaved (i.e., relaxing the seam below). The 30 m separation of the primary seams (i.e., 30 m between 3a and 6, and also between 6 and 7) is well within the mechanical influence produced by mining of the coal on either side.

6.0 Uskovskaya CMM Project Evaluation

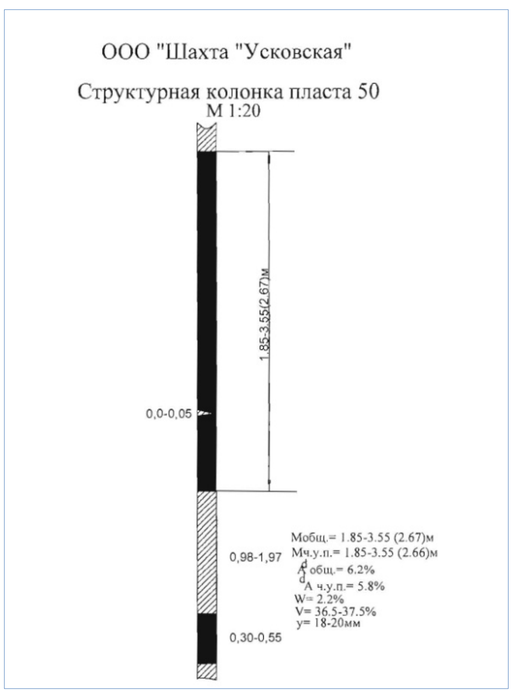
6.1 Summary of Mine Characteristics

The coal measures in the Uskovskaya mine area are approximately 260 m thick and contain approximately 13 m of coal within six thick seams. The coal is Carboniferous in age and is low-ash, low-sulfur, and high-heat content coking and thermal coal. **Table 14** shows some of the characteristics of the coal seams in the area. Mining began in 1966 and currently only seam 50 is being mined; at the time of the study future mining of other seams was uncertain. **Figure 24** shows the stratigraphic column of seam 50.

Table 14. Characteristics of the coal seams in the Uskovskaya mine area

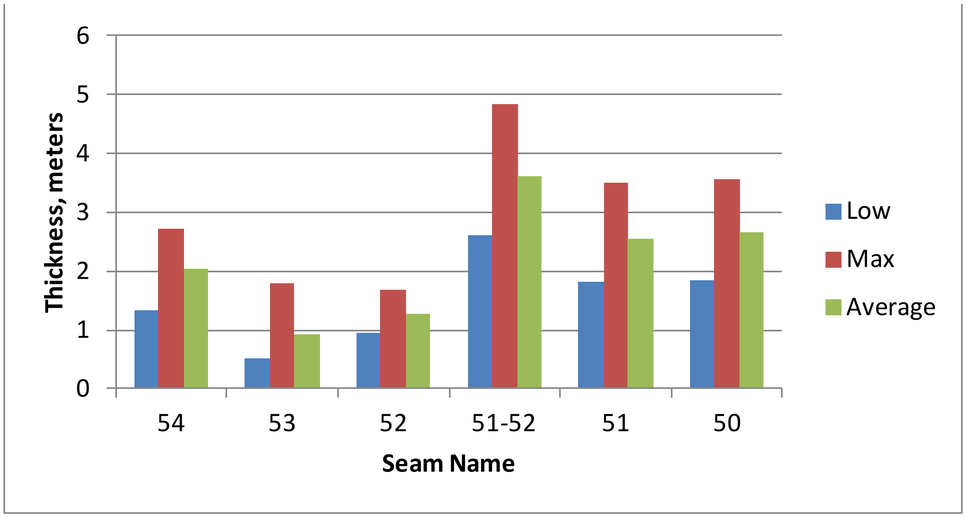
Seam Number	Thickness, m			Density t/m^3	Ash %	Moisture %	Volatile %	Sulfur %	Phosphorus %	HV, kcal/kg
	Low	Max	Avg.							
54	1.33	2.7	2.03	1.33	6.6	7.1	35.9	0.62	0.032	8,177
53	0.5	1.8	0.92	1.30	7.9	4.0	37.4	0.80	0.027	8,188
52	0.96	1.67	1.28	1.28	6.6	5.0	37.7	0.51	0.049	8,181
51–52	2.61	4.83	3.6	1.40	7.3	5.5	36.4	0.48	0.034	8,224
51	1.82	3.49	2.56	1.38	7.3	5.3	37.4	0.42	0.040	8,226
50	1.85	3.55	2.67	1.26	5.8	5.8	37.5	0.40	0.042	8,340
Total or Avg.	**9.07**	**18.04**	**13.06**	**1.33**	**6.9**	**5.5**	**37.1**	**0.54**	**0.037**	**8,223**

Figure 24. Representative stratigraphic column of seam 50 in the Uskovskaya mine area



The variation in seam thickness is shown in **Figure 25** by seam name. One longwall panel is being mined in seam 50. The mine is recovering about 2.5 MMT of coal per year at about a 300-meter depth. The mining depth is not expected to increase in the future.

Figure 25. Coal seam thickness by name in stratigraphic order from top to bottom



6.2 Gas Resources

The gas content of the mined coal varies from 5 to 20 m^3/tonne. Annual emissions data are presented in **Table 15**. The percent degas column is the percentage of total emissions from the degasification system. The last column, specific emissions, is based on the average yearly production rate over a five-year period of 2.763 MMT of coal per year.

Table 15. Annual average emission numbers for Uskovskaya mine

Year	m^3/min CH_4				% Degas	Specific Emissions, m^3/t
	VAM	Degas	Bleeder	Total		
2011	53.9	23.6	29.1	106.6	22.1%	44.14
2010	47.5	22.2	18.3	88.0	25.2%	36.44
2009	57.8	13.1	0	70.9	18.5%	29.36
2008	60.3	0.5	0	60.8	0.8%	25.17
2007	62.5	1.3	0	63.8	2.0%	26.42

6.2.1 Ventilation Air System

There are three ventilation fans in operation, two are positive pressure and one is negative pressure. The rates for two of the fans are shown in **Table 16**. The gob bleeder shaft is estimated to run from 0.80% to 1.5% methane, with an average of 1.2%.

Table 16. Uskovskaya ventilation fans

Air Rate, m^3/min			
Fan	**Min.**	**Max.**	**Avg.**
No. 1	8,200	12,000	10,400
No. 2	6,100	9,200	7,800
Bleeder	4,200	4,200	4,200

6.2.2 Pre-Mining Gas Drainage System

The in-mine drainage wells are networked together with a piping system and the gas transported to three pre-mine gas pumping stations: Lennetal 2-229, MIIV-RB, and MIIV-RB 50-40. The MDU 110RB (4 RB-DV105) is a water ring pump that applies a very high suction pressure. It is believed that mine air is entering the pipe at the in-mine methane drainage boreholes and diluting the gas to the low values shown in **Table 17.** The Lennetal 2-229 and the MIIV-RB pumps are standard dry pumps set up as a methane extraction system with inlet methane concentration control, which uses a methane concentration sensor and speeds up or slows down the pump on a proportional, integral, and derivative hysteresis loop to ensure that a target of greater than 25% methane is achieved. The system also initiates pump startup and shutdown, and controls a recirculation valve for fine concentration and suction control. This system manages suction and prevents over-draining.

The three pump stations drain gas from a series of boreholes drilled into the developed longwall panels about 12 to 18 months before the panels are mined. Currently, in-mine boreholes are drilled only into the seam to be mined and no cross-measure boreholes are used for post-mine gob drainage.

The reported pump station total gas rates, methane concentrations, and methane rates are shown in **Table 17**, **Table 18**, and **Table 19**.

Table 17. Uskovskaya pump station total gas rates

Total Gas, m^3/min			
Pump Station	**Min.**	**Max.**	**Avg.**
Lennetal 2-229	40	52	46
MIIV-RB	50	64	57
MDU 110RB (4 RB-DV105)	110	120	115
Total	**200**	**236**	**218**

Table 18. Uskovskaya pump station methane concentration

$\%CH_4$			
Pump Station	**Min.**	**Max.**	**Avg.**
Lennetal 2-229	25.0	30.0	25.0
MIIV-RB	25.0	29.0	27.0
MDU 110RB (4 RB-DV105)	3.1	3.5	3.3

Table 19. Uskovskaya pump station methane rates

m^3/min CH_4			
Pump Station	**Min.**	**Max.**	**Avg.**
Lennetal 2-229	10	16	12
MIIV-RB	13	19	15
MDU 110RB (4 RB-DV105)	3	4	4
Total	**26**	**38**	**32**

6.2.3 Post-Mining Gas Drainage System

It was discovered during the site visit that vertical gob wells are being drilled from the surface. These wells are 150 millimeters in diameter and spaced about 120 m apart. Mine management estimates that—together with the pre-mine drainage wells—they account for 70% of the total liberated emissions (including VAM), with 20% attributed to pre-mine drainage and 50% attributed to post-mining gob well drainage. Given those values and using the reported VAM, bleeder, and pre-mine drainage values for 2011, significantly more drainage is occurring than what was reported in the pre-site visit questionnaire (**Table 15** above) as shown in **Table 20.** Methane drainage rates by system

Table 20. Methane drainage rates by system

Drainage System	**m^3/min**
VAM	54
Bleeder	29
Gob drainage	138
Pre-mine	55
Total	**277**

Because actual gob well rates and the number of wells operating were not reported, these are rough estimates only and should be verified. One gob well rate was reported as being 36 m^3/min at 57% methane for a rate of 21 m^3/min, which is within the range of initial gob well production in the United States.

6.3 Technical Possibilities for CMM Usage

The study considered and evaluated three options for using drainage gas at the Lennetal 2-229 and MIIV-RB drainage stations to determine their initial technical and economic feasibility: 1) power generation, 2) ventilation air heating using drainage gas, and 3) VAM destruction for greenhouse gas mitigation.

For the power generation option (1), the project was determined not feasible unless the methane content of the gas is improved to 35% or greater (see Table 18 for CH_4 concentrations). The data provided showed no concentrations from the pump stations greater than 35%[10]; therefore, a pro forma economic analysis was not performed. Option 2 is possible with drained gas replacing the ventilation air heating system (which currently uses coal-fired furnaces) if the pump stations are relatively nearby, (the distances from the pump stations to the intake air shafts were not available at the time of study).

There is also potential for capture and utilization of gas from the gob wells, if properly configured, so this option should be considered for evaluation (see "Recommendations").

6.3.1 CMM Usage Option 1: Ventilation Air Heating Using Drainage Gas

Because power generation cannot be achieved at the currently reported methane concentrations, drainage gas for use as a heat source was selected for evaluation and a pro forma economic analysis of a mine air heat source project using gas from both pump stations was conducted. The CMOP Cash Flow Model for an enclosed flare was used, because this type of project is analogous to a flare project.

To heat the ambient ventilation air by 20 degrees C in fans #1 and #2, approximately 7.43 MWth is needed (based on the average flow rate of each fan in **Table 16**, which requires about 11.9 m^3/minute of methane—less than half of the combined flow of methane from the two pump stations, per **Table 18**). If the mine air heating is only required for six months of the year, the approximate savings in coal burned is about 3,400 tonnes/year. Assuming that the mine air heaters are used throughout the year (as simple flares for the six months that the mine air is not heated), 265,878 tCO_2/year emission reductions could be realized (not counting approximately 9,100 tCO_2e not generated by coal displaced by the CMM). **Table** 21 shows the results of the analysis which showed that a carbon price of \$1.00/tCO_2e provided an IRR of 13.8% and that a carbon price of \$1.80/tCO_2e would achieve a 25% IRR; making the project economical.

Table 21. Parameters used to calculate economic analysis for mine air heaters

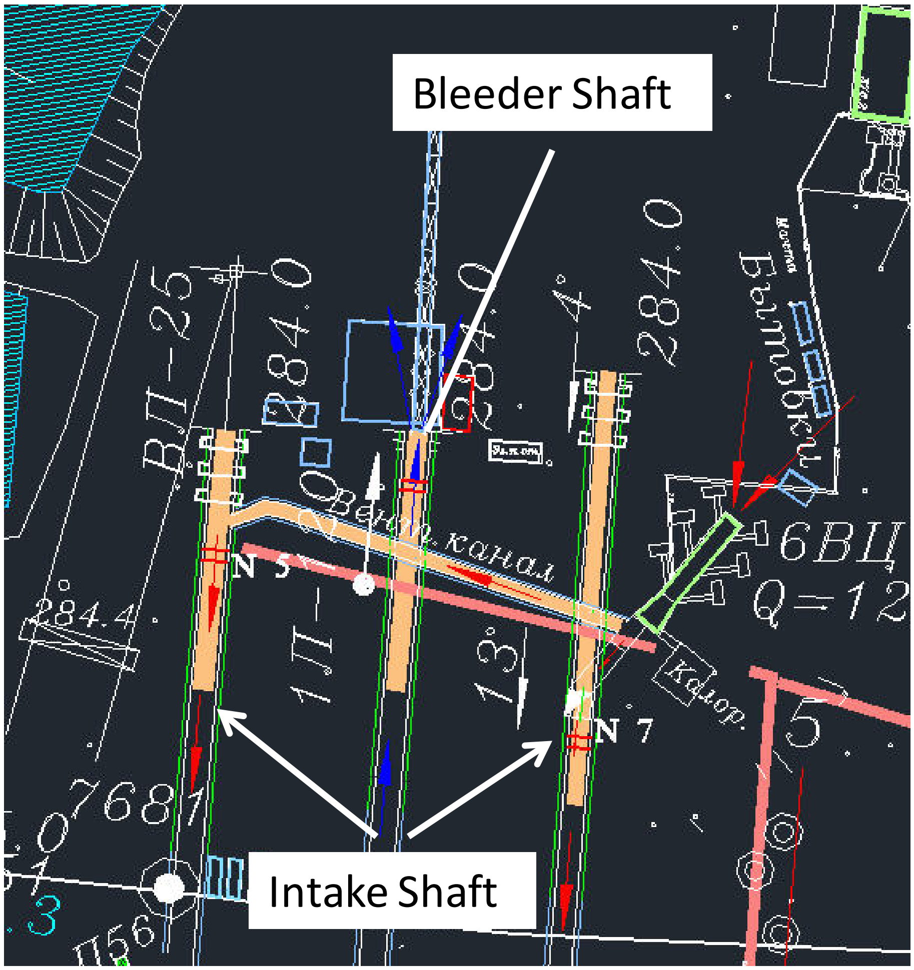
Total capital cost (\$)	1,250,000
Total annual cost (\$/year)	15,000
Coal saving at \$57/tonne (\$/year)	195,000
Carbon price (\$/tCO_2e)	1.00
Project life (years)	10
Carbon credits earned per year (tonne/year)	140,000
Internal rate of return (%)	13.79
10% net present value (\$)	200,000

[10] According to "Instruction on the Degasifying of Coal Mines No. 679" (a rule for CMM utilization issued on December 1, 2011, by Russian federal regulatory authority RozTechNadzor), the methane concentration should be higher than 25% for gas flaring, 30% in boilers, 35% in gensets, and 50% when methane is utilized for domestic purposes.

6.3.2 CMM Usage Option 2: VAM Destruction for Greenhouse Gas Mitigation

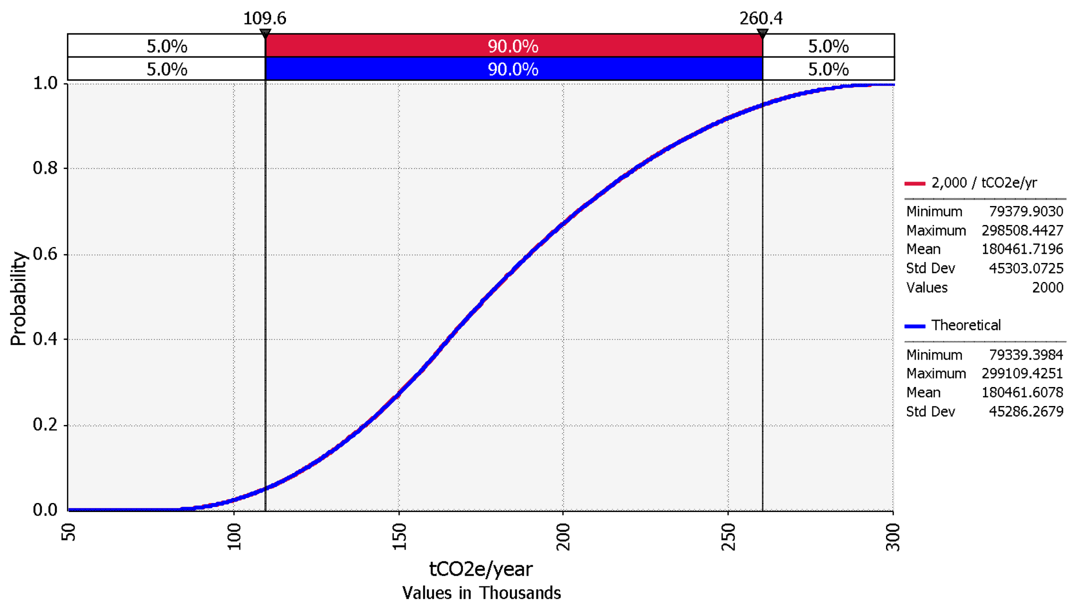
Figure 26 shows the relative locations of fan 1 and fan 2, which are positive pressure fans, and the bleeder fan on the gob drainage bleeder shaft.

Figure 26. Intake and exhaust (bleeder) fans in the northern area of Uskovskaya



In order to justify the installation of VAM destruction devices, it will be necessary to have a price on the emission reductions that can economically justify the project cost. This value would be considerable as shown in **Figure 27**, where between 109,000 tCO_2e/year and 260,000 tCO_2e/year could be destroyed at a 90% probability (based on information made available for the study).

Figure 27. Cumulative probability distribution for emission reductions from the bleeder shaft



CMOP's Cash Flow Model was used to investigate the carbon price that would enable a profitable project based on a price of carbon. The program inputs are shown in **Table 22**.

Table 22. Parameters used to calculate pro forma economic analysis

Percent methane in the ventilation air	1	%
Recoverable ventilation air flow	105	Mcf/min
Planned project operational lifetime	10	years
Carbon credit unit sale price	1.00	$/tCO_2E$
Installed capital cost of the VAM oxidation system	22	$/cfm
Annual operating and maintenance of the VAM system	1.3	$/cfm-yr
Electrical load of the oxidizer blowers	0.075	kWh/mcf
Cost of electric power used by the project	68	$/MWhr
Inflation rate	2.5	%
Real discount rate	10	%
Royalty, severance tax, and negotiation fees	0	%
Contingency factor	5	%
Hours per year the VAM system will operate	8,000	hrs/year
Annual escalation rate for carbon credits	5	%

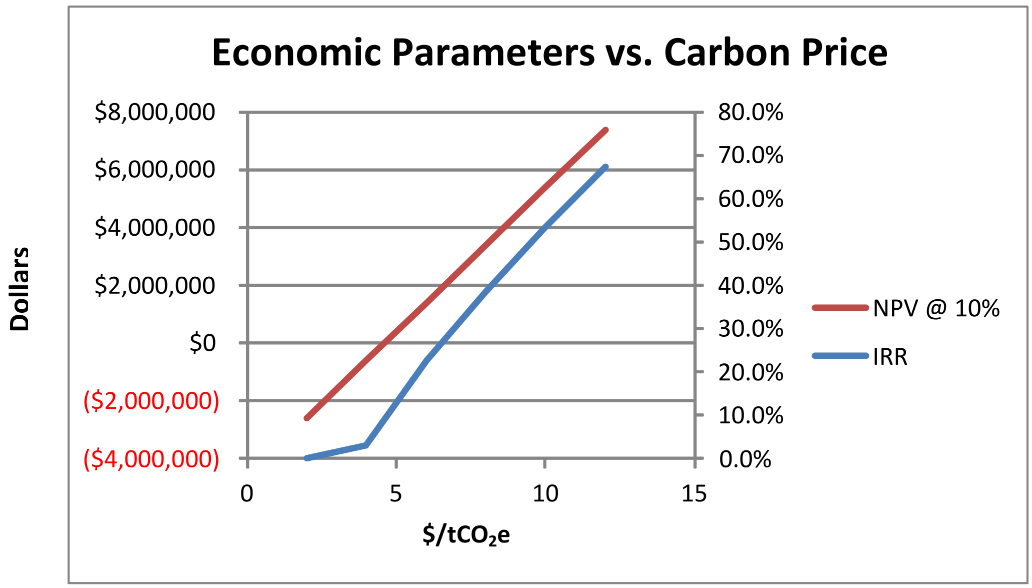
Table 23 shows the results of the pro forma economic analysis.

Table 23. Results of pro forma economic analysis

Total capital cost ($)	2,426,000
Total annual cost ($/year)	394,000
Carbon credits earned per year (tonne/year)	199,725
Internal rate of return (%)	0
Net present value ($)	2,576,000

The goal seek function of the program was used to determine the carbon price necessary (i.e., $5.21/t$CO_2$e) to provide a 25% IRR. **Figure 28** shows the relationship of NPV and IRR to the carbon price.

Figure 28. NPV at 10% discount rate and IRR as functions of carbon price



This VAM economic analysis shows better-than-average performance for VAM projects relative to carbon price because of the richness of the VAM from the bleeder shaft (evaluated at 1%).

6.4 Observations and Recommendations

The following are some initial observations regarding the review of data and recommendations for further investigations at the Uskovskaya mine.

6.4.1 Observations

Because of the alternating use of two underground degasification systems, there is considerable uncertainty in the range of methane content at the bleeder shaft as well as at the Lennetal 2-229 and MIIV-RB pumping stations. A more robust electronic data collection to determine exactly what months each system is operating would enable a better defined analysis (data is currently recoded manually in notebooks). However, the continued use of two systems that compete for the same gas will negatively affect the economics of any recovery and use project.

6.4.2 Recommendations

- Improving the methane content of the drained gas so that it is consistently above 35% will allow evaluation of a power generation project. This could possibly be done through improved procedures to ensure piping integrity to reduce leaks (mine air ingress). Grouting procedures could also be modified to ensure borehole integrity. Actively managing the suction pressure might also improve methane concentration.
- The mines should monitor and record the volumes and methane concentrations from the pump stations and the bleeder shaft more regularly, and forecast the expected time of use of each degas system. The high frequency variability of these parameters can significantly affect the performance of any project that might be proposed.
- Analyze the potential for capturing gas from the surface gob wells. Gob gas production per well along a panel can be short-lived, and capturing and transporting the gas from each well can be expensive and problematic in cold weather. However, some mines in the United States plug and abandon all but one strategically located well, which is operated to manage the gas buildup in the sealed gob area. These wells can be networked with buried pipe to a central facility for use over several years. Such a scheme should be investigated to determine how the mine should be managed to allow for capture and utilization of the recovered gob gas via surface gathering system.

7.0 Summary and Conclusions

The objective of this pre-feasibility study, commissioned by the U.S. Environmental Protection Agency, is to preliminarily evaluate two of Yuzhkuzbassugol United Coal Company's eight coal mines operating in the Kuzbass coal basin for a potential methane recovery and utilization project. Methane emissions from the Kuzbass coal basin account for about 70% of total methane emissions from the entire coal mining sector of Russia. The Alardinskaya and Uskovskaya mines are gassy underground mines and are mining high-grade thermal and coking coal. Both mines operate degasification systems using central extraction pumps, and both are classified as "Super Hazardous," with CMM emissions greater than 15 m^3/t. The mines were selected for a pre-feasibility study due to their favorable characteristics and operations, and because most of the drainage gas produced is higher in methane than at other Yuzhkuzbassugol mines.

7.1 Alardinskaya Mine

The study found potential for the technical and economic feasibility of using drainage gas at the PGM-Lennetal drainage station and heat from VAM destruction at the bleeder shaft. The MDU 195RB (4 RB-DV105) station was not considered due to its consistently low methane content (i.e., less than 5%). Enriching the gas to commercial pipeline quality is not economically feasible because upgrading this gas for even low Btu applications would exceed the price of high-quality natural gas available in the region; therefore, gas sale was eliminated from further consideration.

Analysis shows that the PGM-Lennetal pump station provides a fairly stable gas rate and methane concentration, and can support a 3-MWe power project. Gensets evaluated for this study comprised 1.48 MWe units running at 43% electrical efficiency. The results of the analysis support the installation of two gensets without overbuilding the power station (i.e., about a 60% chance of being able to consistently supply a 2.96-MWe station or larger). Based on two units running 90% of the time, 77,000 tCO_2e/year would be destroyed and the power produced would offset grid power by another 10,000 tCO_2e/year.

The pro forma economic analysis is based on power generation using the reported cost of power for the mines ($68/MWhr) with no inflation or real price escalation. Economic analysis was first based on a carbon price of $1.00/$tCO_2e$, which is the average voluntary market price paid for CMM projects in the United States in 2012. The rate of return at that carbon price was 12.1%. Because the future of carbon prices are very uncertain, a price of carbon was determined that would, together with power sales, produce an acceptable rate of return for typical oil and gas development projects of 25%. This was also done for VAM destruction assuming that the carbon price would be the only income stream aside from coal saved that was being burned for shaft air heating. Even a modest price for emission reductions plays a significant role in making the project economical. A carbon price of $5.20/$tCO_2e$ would provide a 25% IRR for a power generation project. For a VAM heat generation project, it is also necessary to have a suitable price on the emission reductions for project economic feasibility. In this case, a carbon price of $5.21/$tCO_2e$ is necessary to provide a 25% IRR.

7.2 Uskovskaya Mine

The study found potential for the technical and economic feasibility of using drainage gas at the Lennetal 2-229 and MIIV-RB drainage stations if the methane content of the gas is improved. Since the data provided showed no concentrations from the pump stations greater than 35%, a pro forma economic analysis for power generation was not performed for these stations.

There is the possibility of using either drained gas or VAM to replace the ventilation air heating system that is currently using coal-fired furnaces. The location of the bleeder fan located near the intake shafts suggests that a VAM heat recovery system might be advantageous; however, if the pump stations are relatively nearby (the distances from pump station to intake air shafts was not available), heating by drained gas may be more economically advantageous. In the heating by drained gas scenario, if the mine air heating is only required for six months of the year, the approximate savings in coal burned is about 3,400 tonne/year. Assuming that the mine air heaters are used throughout the year, 265,878 tCO_2e/year in emission reductions could be realized (not counting approximately 9,100 tCO_2e not generated by coal displaced by the CMM). A carbon price of \$1.80/tCO_2e would improve the IRR from 13.8% to a preferred 25% IRR; making the project economical.

Economic analysis shows better-than-average performance for VAM projects relative to carbon price because of the richness of the VAM from the bleeder shaft (1%). Between 109,000 tCO_2e/year and 260,000 tCO_2e/year in emission reductions could be realized. Although the analysis found heat from VAM destruction at the bleeder shaft might be used for ventilation air heating, a carbon price of \$1.00/tCO_2e produced a 0% IRR. For this project to be economically feasible with a 25% IRR, a carbon price of \$5.21/tCO_2e is necessary.

8.0 Recommendations/Next Steps

It is recommended that both mines collect and store digital data daily for gas rates and methane content at each pumping station and bleeder shaft to document the variability of flow rates and methane concentration at each location (data is currently recorded manually in notebooks). This knowledge would allow for a more accurate and robust feasibility assessment for investment consideration.

It is also recommended that the Alardinskaya mine try in-mine long-hole drainage tests and cross-measure drilling to see if it leads to more rapid degasification and reduces emissions into the gob of active seams. The mine should also analyze gas volumes from the mine to see if they have remained consistently high since 2011, and if so, consider increasing the size of the projects being considered.

For the Uskovskaya mine, minimizing the amount of time that drainage systems are competing is recommended to improve the methane content of pre-mine drainage gas. Also, the mine may want to hire consultants to review a surface gob well drainage program, as there may be ways to improve the capture and utilization of the recovered gob gas. More information regarding the exact location of the drainage stations needs to be gathered to determine if piping the gas to the intake air shafts for mine air heating is feasible. This option shows better economic return for mine air heating than the VAM option based on assumptions on how far the pump stations are from the shafts (1.5 km).

9.0 References

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UNFCCC: http://unfccc.int/di/DetailedByParty/Event.do?event=go

10.0 2014 Addendum

A draft of this report was transmitted in early 2014 to the Yuzhkuzbassugol United Coal Company for review and comment. Additional information and clarifications were provided and addressed as follows:

- Comments received by the ERG team noted that the shafts with high VAM concentrations, which would be targeted for VAM oxidation, are not located near the intake air shaft heating system (approximately 4 kilometers). As a result, shaft heating with heat from VAM oxidation would not be feasible. The ERG team decided to include and maintain the economics of VAM oxidation in the original report in order to determine a suitable carbon price ($/tCO2e) to justify installation of such a system.
- The percent methane in the drainage gas is significantly lower than what was reported for 2012. The methane content of the drainage pump systems at the two mines were updated (original **Table 24** and **Table 25** were revised):

Table 24. Alardinskaya pump station methane rates

CONTENT OF METHANE AT DEGASING UNITS AT ALARDINSKAYA MINE FOR THE YEAR 2013			
% CH_4			
Pumping unit	Min.	Max.	Avg.
PGM-Lennetal	2.89	3.1	2.99
MDU 195RB (4 RB-DV105)	9.85	11.3	10.58

Table 25. Uskovskaya pump station methane rates

CONTENT OF METHANE AT DEGASING UNITS AT USKOVSKAYA MINE FOR THE YEAR 2013			
% CH_4			
Pumping unit	Min.	Max.	Avg.
PGM-Lennetal	10.9	12.5	11.7
MDU 110RB (4 RB-DV105)	10.8	12	11.40
MDU 110RB (4 RB-DV105)	18.4	21	19.7

The Alardinskaya and Uskovskaya coal mines are currently over-draining the boreholes, which results in air being drawn into the neck of the holes (i.e., suction on the drainage boreholes is not being effectively controlled). Each borehole requires a measuring point (for gas concentration monitoring) and a valve to control suction where methane concentration is low (below 40% CH_4). Where suction is reduced, methane concentration will increase, as the methane within the coal is at approximately 100% concentration.

It is essential that the methane concentration at each individual borehole is measured regularly and throttled back by closing the valve to reduce suction, as necessary. Where a borehole is not delivering gas, and is not throttled back, it is capturing suction capacity and pipeline flow capacity away from successful holes. As a result, the bad holes are reducing the effectiveness of the good boreholes (i.e., inaccurate that the higher the suction applied the higher the gas flow).

The higher the suction on an individual borehole the higher the air ingress. Applying *too much* suction to boreholes results in air being transported through the system. By applying *reduced* suction to boreholes, less air will be drawn into the system, and consequently the extraction pump system will use less electricity. A 20% increase in suction will result in significant savings in electricity purchased over a year, which should offset the extra time involved in a drainage engineer controlling and managing the holes.

Where methane is extracted and transported through the mine in the explosive range, the mine is exposing itself to risk that a lightning strike could ignite the gas, which could transition to an explosion passing underground, endangering personnel. While flame arresters are fitted, they will not always work as expected due to poor positioning or endurance burning. Lightning protection installed around extraction plants is not designed to prevent gas being ignited on the extraction plant vent, but is there to prevent structural damage to the extraction plant. This means that the extraction plants are not protected from lightning igniting the gas being vented. The structure of their extraction plant is protected, but the energy in lightning can jump for more than 100 m with more than enough energy to ignite methane.

For the safety of the Alardinskaya and Uskovskaya coal mines, the methane concentration in the transportation system could be better managed and increased. In parallel with the safety benefit, it will also enable the gas to be utilized. The ERG team recommends that the mines carry out a trial period of gas management (as outlined below) including measuring gas flows before and after management.

In addition, the values reported above in **Table 24** and **Table 25**, which are all at or very near the explosive range, negate the viability of utilizing the methane from these pump stations. The ERG team recommends the following gas management steps be initiated to address this situation:

- Identify reasons for the reduction of methane concentration in 2013 (e.g., geology, drilling techniques, mixing too much air, leaks in the system, regulatory).
- Identify solutions to correct the problem(s) and implement low cost corrective actions immediately, including:
  - Measure methane concentration at each borehole to identify any ineffective holes.
  - Reduce suction on these boreholes or block them off completely.
  - Manage the gas concentration by measuring, then reducing suction as necessary.
  - Monitor results of corrective actions.
  - Develop a long-term methane drainage plan.
- Because methane content is at or very near the explosive range (as well as minimizing pumping efficiency) increasing these concentrations should be a high priority.