ArcelorMittal Coal Mines
Karaganda Coal Basin, Kazakhstan

Pre-feasibility Study for
Coal Mine Methane Drainage and Utilization

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Sponsored by:
US Environmental Protection Agency, Washington, DC USA

Prepared by:
HEL-East Ltd
Ruby Canyon Engineering Inc.
Eastern Research Group, Inc.

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CONTENTS

CONTENTS (Continued)

APPENDICES

TABLES AND FIGURES

ACRONYM LIST

AM	JSC ArcelorMittal Temirtau Coal Division
AMM	abandoned mine methane
CAPEX	capital expenditure
CBM	coalbed methane
CBP	closed borehole pressure
CDM	clean development mechanism
CER	Certified Emission Reduction
CH_4	methane
CHP	combined heat and power
CMM	coal mine methane
CMOP	Coalbed Methane Outreach Program
CNG	compressed natural gas
GHG	greenhouse gas
HEL	higher explosive limit
id	internal diameter
IRR	internal rate of return
JI	joint implementation
km	kilometer
kPa	kilopascal
LEL	lower explosive limit
LNG	liquefied natural gas
LRVP	liquid vacuum pumps
M	million
mBarG	millibar (gauge) =100Pa (gauge)
mD	millidarcy
MJ/m^3	million joule per cubic meter
mm	millimeter
Mt	million tonnes
Mtoe	million tonnes oil equivalent
MWe	Megawatt electrical
OPEX	operational expenditure
PD	positive displacement
PDD	project design document
p.m.e.	pure methane equivalent
RH	relative humidity
Tonne	metric tonne
UNDP	United Nations Development Program
U.S. EPA	United States Environmental Protection Agency
VAM	ventilation air methane
VCS	verified carbon standard
WHRB	waste heat recovery boiler

ACKNOWLEDGEMENTS

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EXECUTIVE SUMMARY

This pre-feasibility study was sponsored by the U.S. Environmental Protection Agency (EPA) under the auspices of the Global Methane Initiative (GMI), of which both the United States and Kazakhstan are partners. The study was conducted by Eastern Research Group, Inc. (Massachusetts, United States), with support from HEL-East Limited (United Kingdom) and Ruby Canyon Engineering (Colorado, United States).

The objective of this study is to investigate the feasibility of a CMM recovery and utilization project at six mines owned and operated by JSC ArcelorMittal Temirtau Coal Division (AM). The gas resource data provided by AM are analyzed to determine the current and future projected gas resource from the six mines. Availability factors, which take into account fluctuations in gas flow and concentration, were calculated from historical data and applied to the projected resource data to calculate the realistic future gas resource.

Various CMM end-use scenarios were considered within this study, and a cost benefit analysis was performed on the most suitable end use. Economic sensitivity analyses were also performed to demonstrate the sensitivity of the project to various economic assumptions made by the ERG team.

ArcelorMittal Overview

ArcelorMittal (AM) owns and operates eight underground coal mines located in the Karaganda coal basin in Kazakhstan. Due to high gas drainage rates and significant methane concentrations, AM is considering six of the eight coal mines for gas utilization. These six mines that are the focus of this study include: Kuzembaeva, Saranskaya, Abayskaya, Kazakhstanskaya, Lenina, and Tentekskaya.

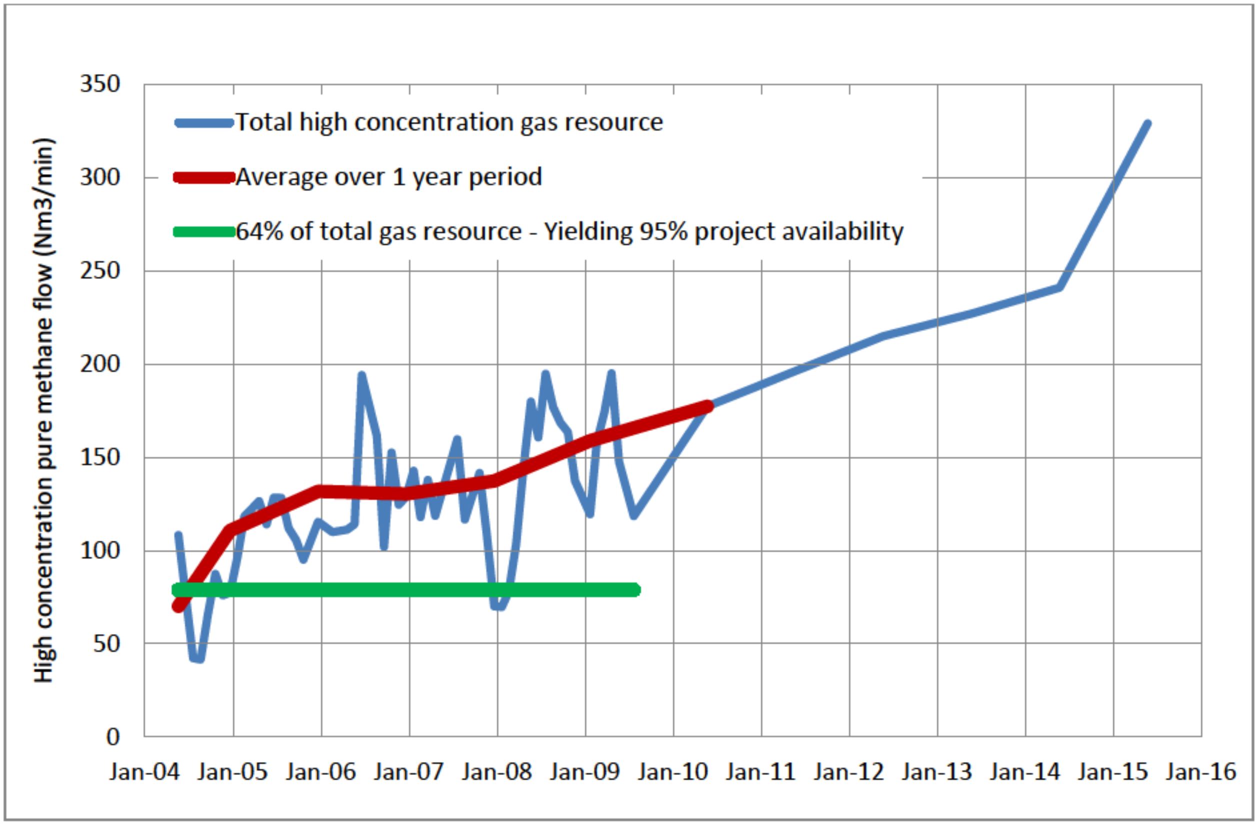
The coal seams mined by AM are considered to be highly gassy, with in-situ methane contents of 8.5 – 27 m^3/tonne. The management at AM has been active in implementing advanced methane drainage techniques in order to improve drainage capture efficiency and mine safety. AM is also active in the field of CMM utilization— first utilizing CMM in modified coal boilers to generate hot water for shaft heating in winter months. In 2011, AM installed a 1.4 MWe reciprocating gas engine generator set at its Lenina mine to demonstrate the feasibility of CMM-fueled power generation in Kazakhstan. The success of this demonstration project lead the development of this preliminary feasibility study on the six AM mines with high CMM flows.

Gas Resource

The AM coal mines within this study use a variety of gas drainage methods to capture methane and bring it to the surface via multiple surface extraction plants. Due to a combination of difficult geological conditions and drainage methods employed, a majority of the drained CMM is captured at low concentration (5-20% methane) and is considered unsafe to utilize. However, where coal seam geology allows, more effective methods of drainage enable methane to be captured at higher concentration (>25%). This study focuses on utilizing the methane that is in the safe concentration range for CMM projects (>25%).

When assessing the gas resource, it is vital to be conservative and identify the gas resource portion that is available at least 95% of the time. AM provided detailed gas flow data on the drainage systems that would be considered for a CMM project. This data is summarized in Figure E-1. The blue line represents the high concentration CMM flow measurements, the red line represents an annual average CMM flow rate, and the green line represents the high concentration gas resource that would reliably provide a 95% project availability over the time period between June 2004 and August 2009.

Figure E-1. Total historical and projected high concentration gas



Options for CMM Utilization

There are many commercially proven options for utilizing CMM. Based on an evaluation of ten options, power generation using reciprocating gas engines with waste heat recovery is recommended at AM mines where a heat load exists, and simple reciprocating engines without heat recovery is recommended where no heat load exists.

This assessment concludes that the CMM quality is not sufficient at current gas market prices to support projects based on CMM enrichment for pipeline, CNG or LNG applications. The distributed nature of the AM mines and lack of necessary local infrastructure make CMM projects that are based on district heating, industrial raw CMM use, slurry drying, and domestic raw CMM use, impractical. The CMM quality is a mismatch for use in gas turbines. Colliery hot water use is too seasonal, and the flaring or oxidation of CMM provides little revenue stream at current carbon prices.

The recommended power generation project would comprise several distributed power plants, each utilizing fuel collected from several gas extraction stations at a specific mine. In this way, the plants would optimize having the benefits associated with collection of gas from several stations, to accommodate variations in gas flow and quality from different faces of the mine. This method also ensures that minimal gas transportation pipeline infrastructure is required.

Evaluated Project Design

Where high concentration gas is being drained by multiple sources at one mine, those sources could be connected using a gas pipe grid. Based upon the quantity of electricity that can be produced with an availability of 95%, the net energy production is estimated to be 19 MWe.

An effective method to capitalize on an increasing projected gas resource is to split a CMM project into phases. The modular nature of reciprocating gas generator sets suitable for utilizing CMM means that it is easy and cost effective to increase the capacity of an installed power plant by simply installing additional generator modules. This assessment is based on the development of a power generation project in two phases: phase 1 would be sized based on accurate drainage data through 2009 and sized conservatively at 19 MWe. The timing of phase 2 would be approximately 2 years from the start of the implementation of phase 1 and sized for an additional 21 MWe.

The individual coal mine contributions to the overall project installed capacity are summarized in Table E-1.

Table E-1. Contribution of each mine to Phases 1 and 2

	Phase 1 Installed capacity (MWe)	Phase 2 Installed capacity (MWe)	Total Installed capacity (MWe)
Kuzembaeva	3	4	7
Saranskaya	2	10	12
Abayskaya	8	3	11
Kazakhstanskaya	2	0	2
Lenina	3	3	6
Tentekskaya	1	1	2
Total	**19**	**21**	**40**

Economic Analysis

A standard discounted cash flow model was used to evaluate the economic performance of the two CMM power project phases discussed in the previous section for the six AM mines. The key economic parameters used in the discounted cash flow model are presented in Table E-2.

Table E-2. Input parameters for the discounted cash flow model

Parameter:	units	value
2011 power price	$(USD)/MWh	50.00
Rate of inflation for power	% pa	11.4
Rate of inflation for O&M	% pa	7.4
Tax rate	% pa	15.0
Discount rate for NPV	% pa	10.0
Engine Capacity Factor	% pa	75.0

The capital cost of the proposed project is detailed in Table E-3. These costs were obtained from the engine suppliers. The O&M costs were obtained from the suppliers, as well, and are presented in the form of an O&M fee per kilowatt hour of electricity generated ($/kWh): $0.01377/kWh.

Table E-3. Project capital costs

Project CAPEX Estimate	Cost (USD)
Project Management (two phases)	$450,000
Design	$150,000
Design Institute	$3,000,000
Safety Institute	$50,000
Phase 1 Power Generation 19 MWe	$13,919,345
Phase 2 Power Generation 21 MWe	$15,384,539
Gas Transport	$15,000,000
Grid Connection for 6 sites	$6,060,000
CAPEX Total for Phase 1 & 2	**$54,013,885**
CAPEX Phase 1	$38,629,345
CAPEX Phase 2	$15,384,539

The results of the discounted cash flow analysis are shown in Table E-4. Table E-5 presents the summary financial performance parameters. The cumulative cash flow becomes positive in the 5th year and results in a 10 year return on investment of 13.3%.

Table E-4. Discounted cash flow analysis

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Nat cash flow ($k USD)	**-$38,629**	**$3,026**	**-$11,804**	**$9,136**	**$10,709**	**$12,132**	**$13,733**	**$15,532**	**$17,554**	**$19,825**
Cumulative net cash flow ($k USD)	**-$38,629**	**-$35,603**	**-$47,407**	**-$38,271**	**-$27,562**	**-$15,430**	**-$1,697**	**$13,835**	**$31,389**	**$51,214**

Table E-5. Financial summary

NPV (10% discount rate)	$7,634,000 (USD)
10 yr IRR (Equity financed)	13.3%
Project payout, years	6

Sensitivity Analysis

There is considerable uncertainty in three of the input variables: gas availability factor, power price inflation, and the Kazakhstan tax rate. Therefore, a sensitivity analysis was conducted on these three variables to test the economic results of one of the extreme values occurring. The ranges of uncertainty used in the sensitivity analysis for gas availability, power price inflation, and the Kazakhstan tax rate are based on experience with similar projects in the region. The results of the sensitivity analysis are shown in Figures E-2 and E-3.

Figure E-2. Results of the sensitivity analysis on NPV ($k)

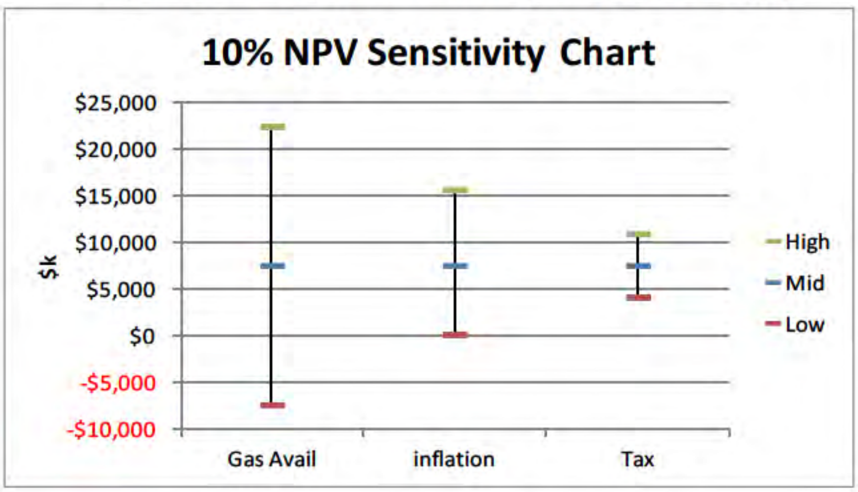
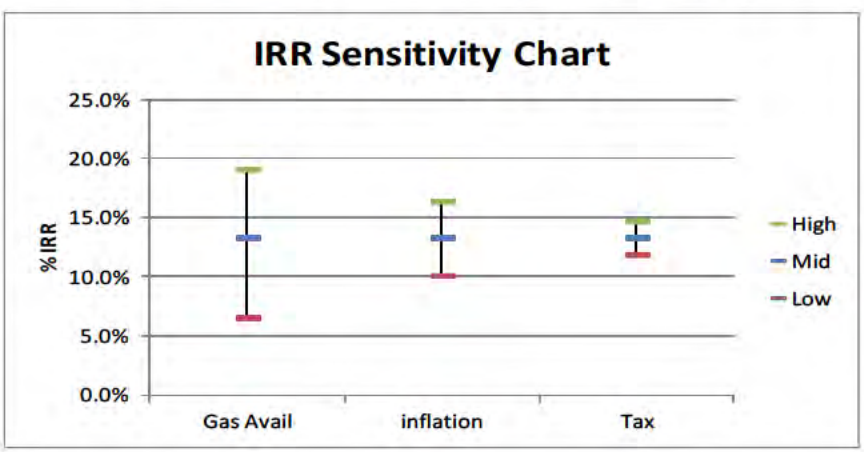


Figure E-3. Results of the sensitivity analysis on IRR (%)



Conclusions and Recommendations

Based on a technical and commercial evaluation, power generation using reciprocating gas engines with waste heat recovery is recommended at AM mines where a heat load exists, and power generation using simple reciprocating engines without heat recovery is recommended where no heat load exists. Current infrastructure and market constraints limit the practicality of employing other types of projects for the use of CMM from the AM mines. Developing the project in phases will reduce the economic risk of the project. The first phase would be based on a conservative assessment of current gas flow rates, and a second phase would be based on the performance of the first phase and proven CMM flow rates as the mines expand operations.

As a next step, it is recommended that ArcelorMittal conduct a full economic feasibility analysis of an electric power generation project for the six mines investigated in this report that is based on the most up to date mining plans and actual contract prices for gas pipelines, power generation equipment, and site construction/installation. The full economic analysis would optimize the number, size and location of the power generating plants and evaluate the sites where combined heat and power may be economically attractive.

It is also recommended that the project owner investigate the current strategy of the Kazakhstan Government regarding climate change regulation and carbon emissions reduction mechanisms. The project owner should investigate whether this project can be assisted by any national incentives provided by these future strategies. In parallel with this activity the project owner should investigate voluntary emission reduction mechanisms to determine whether carbon revenue can be generated from these sources. If additional incentives are identified, they may also change the results of the project options analysis discussed in Section 3.0 of this report and the full feasibility study should reinvestigate these options.

1.0 PROJECT OVERVIEW

1.1 Background

This feasibility study was sponsored by the U.S. Environmental Protection Agency (EPA) under the auspices of the Global Methane Initiative (GMI) (formerly Methane to Markets Partnership), of which both the United States and Kazakhstan are members. The study was conducted by Eastern Research Group, Inc. (Massachusetts, United States), with support from HEL-East Limited (United Kingdom) and Ruby Canyon Engineering (Colorado, United States).

The objective of this study is to investigate the feasibility of a CMM recovery and utilization project at the following 6 AM mines: Kuzembaeva, Saranskaya, Abayskaya, Kazakhstanskaya, Lenina, and Tentekskaya. The gas resource data provided by AM are analyzed to determine the current and future projected gas resource from the six mines. Availability factors, which take into account fluctuations in gas flow and concentration, were calculated from historical data and applied to the projected resource data to calculate the realistic future gas resource.

Various CMM end-use scenarios were considered within this study, and a cost benefit analysis was performed on the most suitable end use. Economic sensitivity analyses were also performed to demonstrate the sensitivity of the project to various economic assumptions made by the ERG team.

1.2 ArcelorMittal Overview

JSC ArcelorMittal Temirtau Coal Division (AM) owns and operates eight underground coal mines located in the Karaganda coal basin in Kazakhstan. Due to high gas drainage rates and significant methane concentrations, AM is considering six of the eight coal mines for gas utilization. These six mines that are the focus of this study include: Kuzembaeva, Saranskaya, Abayskaya, Kazakhstanskaya, Lenina, and Tentekskaya.

The coal seams mined by AM are considered to be highly gassy, with in-situ methane contents of 8.5 – 27 m^3/tonne. To facilitate safe mining practices, comprehensive pre- and post-mining methane drainage schemes are operated at each coal mine. The management at AM has been active in implementing advanced methane drainage techniques in order to improve drainage capture efficiency and mine safety. AM is also active in the field of CMM utilization— first utilizing CMM in modified coal boilers to generate hot water for shaft heating in winter months. In 2011, AM installed a 1.4 MWe reciprocating gas engine generator set at its Lenina mine to demonstrate the feasibility of CMM-fueled power generation in Kazakhstan. The success of this demonstration project is discussed further in Section 1.6.

1.3 Production Summary

In 2010, six AM mines depicted in this study produced 10.87 million tonnes of coking bituminous coal, which was utilized as fuel for steel production in the nearby Temirtau Steel Works. Coal production for the six coal mines considered in this study are summarized in Table 1. For a more detailed summary of individual coal characteristics, see Appendix C.

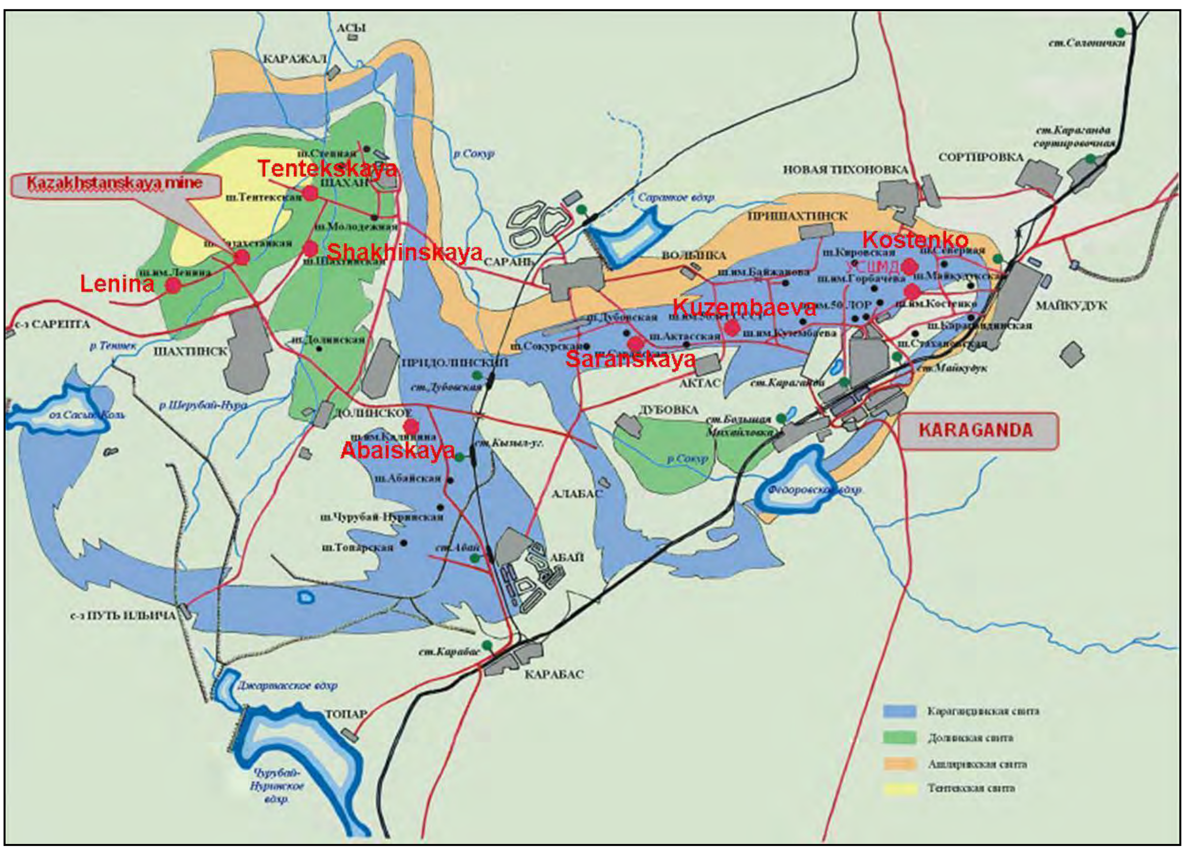
Table 1. Historical Coal Production

Mines	Annual coal output (Mt)											
	1970	**1975**	**1980**	**1985**	**1995**	**2001**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Kuzembaeva	1.64	2.16	1.83	1.69	0.80	1.22	1.29	1.87	1.19	1.56	1.72	1.64
Saranskaya	0.91	0.82	0.87	1.26	0.47	1.51	1.51	1.29	1.50	1.11	1.42	1.29
Abayskaya	0.76	1.03	1.17	1.35	0.62	0.81	1.21	1.28	1.29	0.77	1.20	1.16
Kazakhstanskaya	1.08	2.49	2.24	1.95	0.57	1.26	0.97	1.45	1.85	1.28	0.95	1.43
Lenina	2.55	2.90	2.38	2.43	1.57	1.28	1.53	1.60	1.82	1.49	1.45	1.26
Tentekskaya	-	-	1.67	2.54	1.05	0.90	1.25	0.91	1.50	0.86	0.93	0.91
TOTAL	**9.43**	**13.74**	**15.51**	**16.66**	**7.55**	**9.69**	**11.16**	**11.54**	**12.20**	**11.03**	**11.10**	**10.87**

1.4 Location

The mines of AM are located in the Karaganda coal basin. Due to structural peculiarities, the coal basin is divided into three geology-based mining areas: Karagandinskiy, Sherubay-Nurinskiy, and Tentekskiy. These mining areas are shown in Figure 1. The geological plan of the mining area belonging to AM is shown in Appendix C, Figure C-1.

Figure 1. Map of Karaganda Mining Region



The Kuzembaeva and Saranskaya mines operate in the Karagandinskiy area, located in the Saran district of Karaganda. In accordance with the geological mining area division, it is identified in the northwest and partially southwest limbs of the Karaganda syncline. In terms of administration arrangements, the mines report to the town of Saran in the Karaganda region.

The Abayskaya mine operates in the Sherubay-Nurinskiy area located in the southern part of the northeast limb of the Sherubay-Nurinskiy syncline (Brachy syncline). In terms of administration, the mine reports to the Bukhar-Zhyrau city district of the Karaganda region.

Kazakhstanskaya, Lenina and Tentekskaya mines operate in the Tentekskiy area. Tentekskaya is located in the northwest part of the Sherubay-Nurinskiy syncline. In the west, coal production is bounded by the Tentekskiy fault, and in the east by Sherubay-Nurinskiy upcast fault. The mould is of asymmetrical form and slightly outstretched in a southwest direction. It is 15 kilometers (km) long and 10 km wide. In terms of administration, the mines report to the Bukhar-Zhyrau city district in the Karaganda region.

1.5 Geological Summary

The Karaganda coal basin is more than 3,000 kilometers square (km^2) and is formed by strata of Upper Devonian and Carboniferous ages, Mesozoic and Cenozoic formations. Their thickness is about 4,500 m, with approximately 4,000 m being coal-bearing formations. The basin is divided into three large synclines (from west to east): Sherubay-Nurinskaya, Karagandinskaya, and Verkhnesokurskaya. Coal formations are defined by commercial coal-bearing strata in four suits: Ashlyarikskaya, Karagandinskaya, Dolinskaya, and Tentekskaya seam sections, with a total thickness of about 2,400 m. The coal formation has up to 65 working seams with total thickness of 80-100 m.

Seam structures are usually of complex type; some seams are discontinuous both in structure and in thickness. All coals have good structure. The best quality coal is found in the Dolinskaya (D) seam section and in the top part of the Karaganda (K) seam section. Coking bituminous coals are spread within the boundaries of operating mines. There are also some discontinuous beds of brown coals. Table 2 summarizes the mine and coal seam characteristics of the six mines. A more detailed summary of individual coal seam characteristics is presented in Appendix C.

Table 2. Summary of Mine and Coal Seam Characteristics

Mine Name:	Kuzembaeva	Saranskaya	Abayskaya	Kazakhstanskaya	Lenina	Tentekskaya
2010 Coal production	1.64	1.3	1.16	1.43	1.26	0.91
Production seams	K7, K10	K7, K10, K12	K10, K12	D6, D11	D6, D10	D6, D12
Mining depth	540 - 600	541 - 600	550-620	351 - 480	350 - 480	352 - 480
Seam thickness	4.37 - 5.2	4.37 - 5.3	4.2 - 4.6	1.1 - 5.7	1.1 - 5.6	1.1 - 5.8
Coal gas content (m3/tonne)	15-25	15-25	8.5-27	20.7-25.4	20.7-25.3	20.7-25.5
Coal calorific value (GJ/tonne)	35.3	35.3	35.5	35 - 37	34 - 37	36 - 37
Average H2 content	4.7	4.7	4.6	5.3 - 5.10	5.3 - 5.9	5.3 - 5.11
Average Carbon content	90.3	90.3	90	88 - 89	87 - 89	89 - 89
Sulphur content	0.26 - 1.34	0.26 - 1.35	0.64-1	0.36 - 0.46	0.36 - 0.45	0.36 - 0.47
Dirt content in ROM (%)	19.4 - 21.6	19.4 - 21.7	16.3 - 21.4	15.4 - 20.8	15.4 - 20.7	15.4 - 20.9

1.6 Lenina Electric Project

In 2011, AM commissioned a 1.4 MW engine-generator CMM project at their Lenina coal mine. This was the first CMM fueled generator in Kazakhstan and was used to demonstrate the practicality and performance to CMM fueled electric power. The unit has achieved a 95% availability and has produced almost 9 million kWh of electric power. This has resulted in a 20% reduction in purchased power for the mine. Power is provided by a containerized high efficiency, spark ignition, lean burn engine that was installed for a capital cost of $1.5 million (US). The CMM is provided by surface and in-mine drainage of pre-mine and gob CMM produced by longwall mining operations.

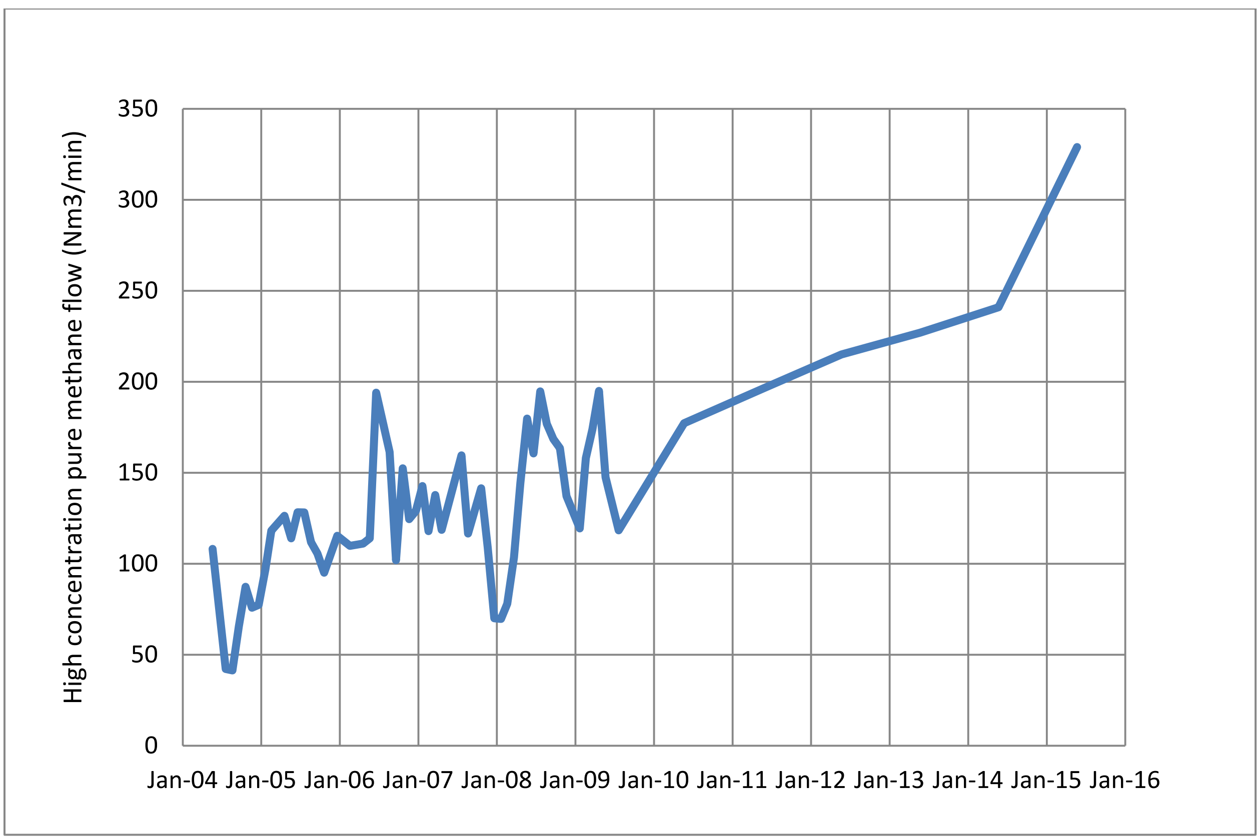
2.0 GAS RESOURCE ASSESSMENT

2.1 Calculation of Gas Resource Profile

The AM coal mines within this study use a variety of gas drainage methods to capture methane and bring it to the surface via multiple surface extraction plants. These are discussed further in section 4.0. Due to a combination of difficult geological conditions and drainage methods employed, a majority of the drained CMM is captured at low concentration (5-20% methane) and is considered unsafe to utilize. However, where coal seam geology allows, more effective methods of drainage enable methane to be captured at higher concentration (>25%). This study focuses on utilizing the methane that is in the safe concentration range for CMM projects (>25%).

Historical and projected gas drainage data for every methane extraction station within the six mine group was provided by AM based upon gas analysis that they conducted in 2010. This historical data, presented in Figure 2, contains actual measured monthly methane concentration and flow for the period June 2004 to August 2009. These historical data were analyzed in detail to validate the projected gas data provided by AM for the period of 2012 through 2015.

Figure 2. Historical and projected gas resource

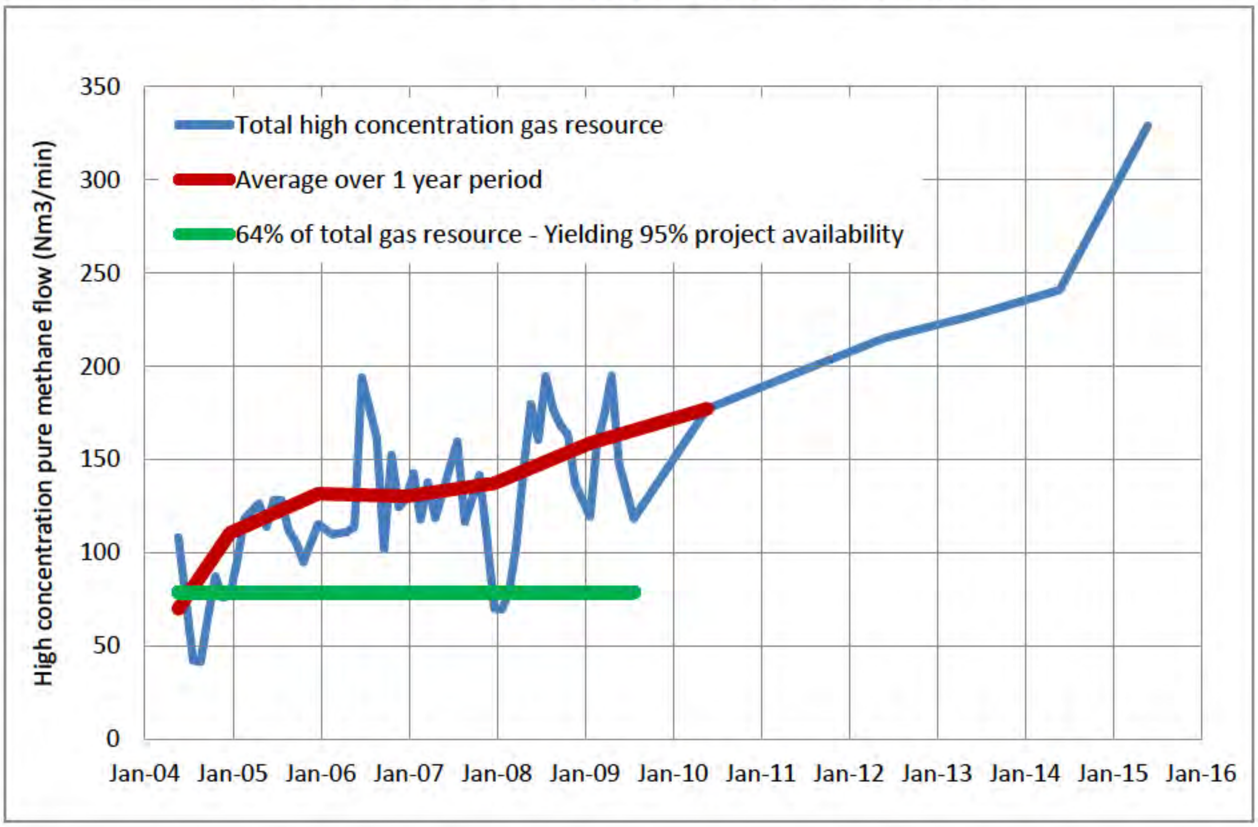


The historical measured gas resource data are in agreement with the projected gas resource. The projection shows an almost constant increase in gas resource from 2010 to 2014. The gas resource increase beginning in 2015 is attributed to the Abayskaya mine beginning production in the K10 seam.

2.2 CMM Utilization Project Sizing

When assessing the gas resource, it is vital to be conservative and identify the gas resource portion that is available at least 95% of the time. That is, at no more than 5% of the time would the project output be reduced due to gas shortage. AM provided detailed gas flow data on the drainage systems that would be considered for a CMM project. This data was summarized to create the curves in Figure 3. The blue line represents the high concentration CMM flow measurements provided by AM and the red line represents an annual average CMM flow rate. The green line on Figure 3 represents the high concentration gas resource that would reliably provide a 95% project availability over the time period between June 2004 and August 2009.

Figure 3. Total historical and projected high concentration gas



3.0 OPTIONS FOR CMM UTILIZATION

There are many commercially proven options for utilizing CMM. This section considers the factors associated with various utilization options as compared to the available CMM resource, AM energy needs and local energy infrastructure at the six AM mines included in this study.

3.1 Enrichment to Pipeline Gas, LNG, or Compressed Natural Gas (CNG)

The CMM gas being generated by the AM mines is a combination of pre- and post-drainage gas, but because the coal is low permeability, and over-draining is common, typical methane concentrations are in the 3% to 60% range, with the majority of methane being in the 15% to 40% range. While it is technically possible to clean this type of gas to the quality required by pipeline, LNG, or CNG applications, the variability of the gas and the high oxygen content make it difficult and expensive. Generally, gas processing to pipeline quality is not commercially practical below 50% methane (the typical threshold for gas cleaning in the United States is 70% methane).

3.2 District Heating

There are district heating network pipelines close to all of the mines and co-generated power at the mine portal would be able to deliver top-up waste heat into these lines, thus displacing coal fired hot water. The coal fired boilers tend to be inefficient; therefore, use of waste heat for district heating could be an attractive option. The power generation plants could be located at different places, some near the mine portal and some at remote drainage sites. Where the generators are at mine portals, the waste heat would be easy to use (low cost of infrastructure connection), but where the generators are remote, the heat connection would have a long and costly infrastructure connection. The remote sites also have shorter installation life compared to the mine portals, since the remote sites move with the advancing mining operations.

3.3 CMM-fueled Reciprocating Engine Generating Sets with Waste Heat Recovery

Reciprocating gas engines are frequently cost effective at the low CMM flowrates and the rapidly changing gas quality experienced at many coal mines. It must be considered whether to opt for centralized power plants housed in buildings or in semi-mobile containerized packages. The variability in post drainage CMM from mine to mine and from face to face, means that the scale of the gas resource can be unpredictable. The level of variability from different extraction plants and their relative locations, require a mix of distribution and centralization, with the ability to move equipment between locations. For this type of installation, containerized generating sets are ideal, because there are minimum costs associated with permanent infrastructure, de-mobilization and re-installation. This means that there will be a number of separate generating plants.

The variable quality and pressure of CMM is a challenge for reciprocating engines and requires special gas/air mixing equipment in the fuel train and an appropriate control governor system. In selection of a gas engine for a CMM project, it is necessary to confirm that the unit has a specially designed gas train, including a specialist fuel mixing valve, governor and flame arrester.

The use of waste heat recovery from the generating sets should be considered where there is a heat load in close proximity that can use the heat. Local heat loads are located at the mine portal, and many of the generators may be used to provide heat, thus reducing the amount of steam coal required for heating by the mine.

Waste heat recovery can be carried out in three alternative design modes:

1) Jacket and cooling water heat recovery,
2) Exhaust heat recovery, and
3) Combined jacket, cooling water and exhaust heat recovery.

The heat loads in the Karaganda region are almost entirely seasonal with an extremely high demand in the winter (5 month cold season) and a very low demand for the remaining 7 months of the year. It is possible to use either container-mounted waste heat recovery boilers (WHRB) or separate waste heat recovery boilers. A container mounted WHRB is really only suited to continuous heat loads, because extended periods of non-use can overheat the system. Therefore, separate WHRB are recommended for the cyclic loads present at AM mines; however, they are not particularly portable.

The lowest capital cost per unit of heat is the use of jacket and cooling water heat. It is common practice during the initial 12 month of plant operation that only waste heat from this source be installed. After 12 months of operation, the power plant load profile is better defined and a detailed cost benefit analysis of using exhaust waste heat could be undertaken.

3.4 CMM-fueled Reciprocating Engine Generating Sets Without Waste Heat Recovery

The previous analysis on reciprocating gas engine generators with waste heat recovery applies similarly to engine generators without waste heat recovery. However, where no heat demand is present, waste heat recovery is unnecessary and would be eliminated from the design.

3.5 Gas Turbines

Standard gas turbine generators are technically suitable for CMM only where the methane concentration is above 40%. Specialized gas turbines can be used below this minimum threshold, but capital costs rise dramatically. Gas turbines typically require an inlet gas pressure of 15 BarG which raises the higher explosive limit to 41%. Because the typical gas concentration across the Karaganda mines is 25% to 90% methane, it is likely that for a significant proportion of the time, the fuel would be compressed into the explosive range. This creates an unacceptable safety risk; therefore, gas turbines are an inappropriate technology for this application.

It should also be noted that gas turbines are relatively inefficient in simple cycle. Gas turbines can be semi-mobile in simple cycle, but when waste heat recovery boilers and steam turbines are added to bring efficiency to above 55%, then the installation becomes permanent and inflexible. However, the flexibility to relocate power generation to new CMM drainage areas is very important.

3.6 Use in Industrial Applications

The sale of CMM for use in industrial boilers and furnaces is an entirely appropriate use for the CMM; however, because there are no such industrial applications nearby, the cost of transportation of the fuel means that this option is not commercially viable.

3.7 Use on Colliery Site for Hot Water or Steam Generation

Use of CMM for onsite heat would require some of the existing coal fired boilers to be retrofitted for CMM, or alternatively for new boilers to be installed specifically for CMM. At many international coal mines where CMM is retrofitted to a boiler originally designed for coal firing, gas train design standards and maintenance standards have been inadequate. Typical problems include: damaged pressure governor, flame arrester removed; methane concentration slam shut over-ridden resulting in a boiler explosion; and no pressure control, flame failure or flame arresters.

While this method represents the least cost option for CMM utilization, the lack of demand for heat during the summer months would mean a poor overall utilization rate, and therefore should be lower in the selection hierarchy than power generation with waste heat recovery, or straight power generation.

3.8 Use On-site for Slurry Drying

AM has one centralized washing plant, therefore only CMM local to this plant could be utilized. This technology requires specialist engineering skills and exhibits low conversion efficiency. For these reasons, this technology is not well suited for AM mines.

3.9 Domestic Gas Distribution in Raw State

Though domestic use of raw gas is technically possible, significant distances (typically >3km) between the location of the CMM and the domestic housing closest to the mines would make domestic gas distribution more expensive. Furthermore, the variability of the gas quality would cause difficulties when injected into the local gas network because domestic appliances are designed for much higher quality gas. The cost of modifying the local infrastructure and delivering the gas to the network will reduce commercial viability.

3.10 Flaring and Oxidation

Generally speaking, neither flaring nor commercial oxidation technologies produce a marketable product. However, these technologies are methods for greenhouse gas (GHG) mitigation. But because Kazakhstan does not have any Designated National Authority or other administration system to allow Joint Implementation (JI) projects, the only carbon credits that could be generated are via Voluntary Emission Reduction schemes, which currently have very low value. Though technical challenges and capital costs are low, the lack of revenue stream means that this method is not viable. A brief economic analysis was performed on oxidation of ventilation air methane (VAM) to confirm that it is not economical at current carbon prices. This analysis is presented in Appendix B.

3.11 Recommendations on a CMM Utilization Project

Based on the above technical and commercial evaluation, power generation using reciprocating gas engines with waste heat recovery is recommended at AM mines where a heat load exists, and simple reciprocating engines without heat recovery is recommended where no heat load exists.

The CMM quality is not sufficient at current gas market prices to support projects based on CMM enrichment for pipeline, CNG or LNG applications. The distributed nature of the AM mines and lack of necessary local infrastructure make CMM projects impractical that are based on district heating, industrial raw CMM use, slurry drying, and domestic raw CMM use. The CMM quality is a mismatch for use in gas turbines. Colliery hot water use is too seasonal, and the flaring or oxidation of CMM provides little revenue stream at current carbon prices.

The recommended power generation project would comprise several distributed power plants, each utilizing fuel collected from several gas extraction stations at a specific mine. In this way, the plants would optimize having the benefits associated with collection of gas from several stations, to accommodate variations in gas flow and quality from different faces of the mine. This method also ensures that minimal gas transportation pipeline infrastructure is required.

Reciprocating gas engine generators achieve around 40% net electrical efficiency in simple cycle. There are many manufacturers of gas engines suitable for CMM projects. The size of the unit required for this project must match both the size of the resource and the variability of the resource quality and pressure. Due to the potential for the CMM quality to drop to 25% methane, engines in the range of 1.2 MWe to 2 MWe would be optimum for this application.

Power generation packages at this size can easily be containerized and moved as the drainage and mining locations vary over time. They can also have either low cost jacket/cooling water heat recovery, or a combination of jacket/cooling and exhaust waste heat recovery for use in heating mine air, space heating, and providing domestic hot water. Because the heating loads are cyclical, it would be necessary to have a separate exhaust heat recovery system.

3.12 Introduction to the AM Electrical Power System

Currently electrical power used by AM is generated by both the local government power company, and by AM themselves, both predominantly from coal fired steam-electric power generators. The external high voltage distribution system is owned by the local government power company. AM owns and operates an internal electric distribution system. The electric power generation by AM with CMM would be embedded within the AM distribution grid. For the initial project phases, almost all power would be utilized within the AM power demand for the mines. It is likely that during certain weekend shutdowns or national holidays, where production slows, there will be export of power onto the local HV distribution network. The frequency of this would need to be evaluated more fully at the engineering stage, but the strong expectation is that the volume of this export would be minimal, at least for the first two phases of power generation. As the CMM power generation network increases, the likelihood of export increases. It is recommended that as part of a commercial development phase, discussions with the local power generator/distribution company are opened.

AM owns, operates, and maintains the distribution system that conveys power from the import network connection into the coal mine medium voltage network. Because the project is based on embedded generation only, grid import and export mechanisms are not applicable to the first phase.

4.0 AM DRAINAGE SYSTEM DESIGN AND SUITABILITY FOR ELECTRIC POWER GENERATION

4.1 Gas Drainage Techniques Employed by AM

A variety of gas drainage techniques are employed across the AM coal mines. Methane drainage block diagrams are presented for each mine in Appendix D. Figure 4 shows a schematic of the drainage employed at Abayskaya mine's K32 face, including in-seam boreholes, vertical surface boreholes, and overcast 3rd gate methane drainage techniques. Other forms of drainage that are also practiced but not shown in Figure 4 include surface pre-drainage boreholes and underground cross-measures drainage. Table 3 summarizes the characteristics of the various drainage techniques employed by AM.

Figure 4. Methane drainage at Abayskaya's K32 face

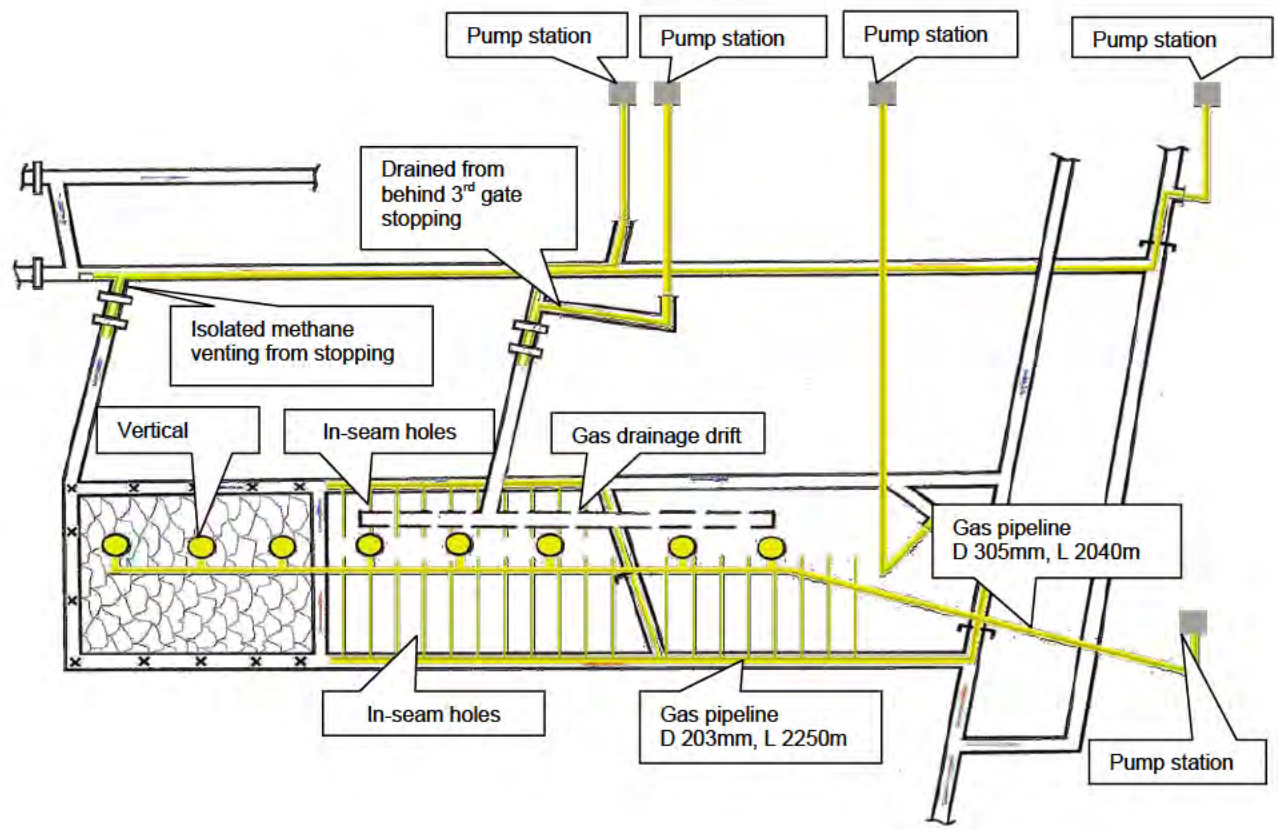


Table 3. Characteristics of drainage techniques employed by AM

Drainage name	Purpose	Method	Gas concentration characteristics
In-seam boreholes	To capture gas from coal before it is de-stressed by mining. Also reduces the risk of outburst in certain coal seams.	Horizontal boreholes drilled into the coal seam from the intake and return gates.	5 – 20% methane (CH_4). Low coal permeability and high vacuum mean that flow of gas into the boreholes is low and significant in-leakage of air dilutes the methane to low concentration.
Vertical surface gob wells	To capture gas from the gob as the face passes underneath; methane is desorbed through the de-stressed strata.	Vertical gob wells drilled from the surface to follow the line of the coal face; they come on stream as the face passes under them and the de-stressed strata becomes permeable.	5 – 80% CH_4. Performance varies widely depending on geological conditions. Well-positioned gob wells intersect with the fractured gob and successfully draw the methane away without much air leakage.
Overhead 3rd gate	To draw gas upwards from the coal face just before the front abutment, where the strata becomes de-stressed.	A roadway driven usually in rock above the coal face (10 – 20m separation). Roadway stopped off at outbye end with drainage applied behind the stopping.	5 – 20% CH_4. The 3rd gate connects into the gob where air can be drawn into the gate in an uncontrolled manner causing dilution of captured methane.
Cross-measures drainage	Targeted boreholes to capture gas at source from the de-stressed gob and overlying coal seams (measures).	Boreholes drilled into the roof of the return gate behind the face line, the angle and length of the borehole is selected to avoid large shear stresses and intersect with overlying coal seams within 50m vertical distance of the working seam.	20 – 50% CH_4. Well-placed boreholes target areas of high permeability in the de-stressed strata. Vacuum must be carefully regulated to minimize air intrusion.
Surface pre-drainage boreholes	To pre-drain gas from virgin coal to de-gas it before mining operations commence.	Boreholes drilled from the surface into virgin coal deposits.	50 – 90% CH_4. Limited air ingress means the gas is high concentration, however flow rate is very low due to the low permeability of the coal.

4.2 Methane Extraction Stations

Across the AM coal group methane is drained using surface methane extraction stations. These stations use two types of extraction equipment:

1. Liquid ring vacuum pumps (LRVP)
2. Positive displacement (PD) blowers

4.2.1 Liquid ring vacuum pumps

Approximately 28 separate LRVP extraction stations are installed across the AM coal group. The individual extraction stations vary in design and size, consisting of anywhere from two to 10 pumps to generate the vacuum that enables drainage (Figure 5). These stations are a combination of large permanent stations located at mine portals and small temporary stations that are used intermittently to drain gas from surface gob wells.

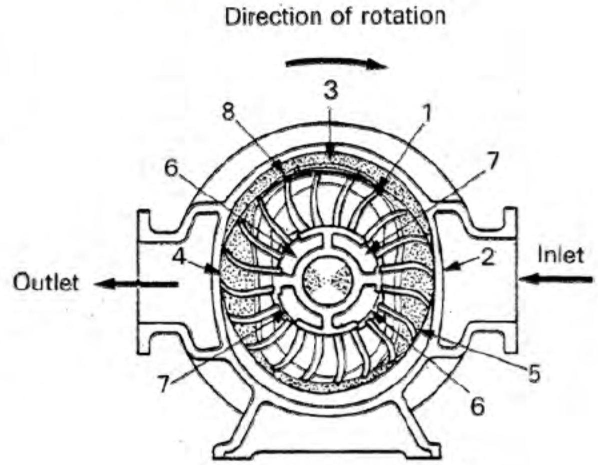
Figure 5. LRVP extraction station

LRVPs use a continual flow of water that is centrifuged around the offset casing (liquid ring) to provide a seal that enables a vacuum to be generated. To ensure effective operation of the pump, the back pressure on the outlet must be carefully maintained to prevent the liquid seal from being drawn out of the casing; this is normally achieved by an automatic pressure control valve—either a mechanical or electrical diaphragm. However, in Kazakhstan this is achieved manually by the station attendant.

LRVPs are robust, reliable pumps that can generate significant levels of suction and tolerate large quantities of dirt in the drained gas stream. Figure 6 shows a cross section of a LRVP. The LRVPs currently installed at the AM coal mines are manually regulated and controlled; as a result, they would require upgrades to various levels of automation and system integration to enable safe drained methane utilization.

The drained gas delivered by LRVPs is warm, 100% humid, and contains entrained water droplets. As a result, it is not suitable for utilization without pre-treatment to remove water and dirt.

Figure 6. Cross section of LRVP



4.2.2 Positive displacement blowers

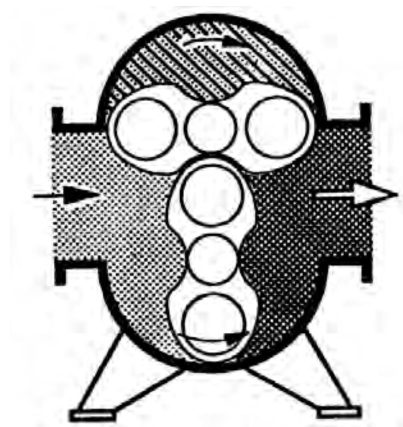
Eight positive displacement (PD) blower extraction stations are installed across the AM coal mines. The stations are containerized units that employ PD blower technology to generate a vacuum. Figure 7 shows a PD blower extraction station.

Figure 7. Positive displacement (PD) blower extraction station

These PD blower stations are automatically controlled and require very little modification to enable safe utilization of drained gas. The PD blower pumps can be configured to vary the speed to maintain a variety of parameters such as methane concentration, vacuum, or back pressure.

PD blowers do not require water to produce an internal seal within the pump. The blowers rely on close tolerances between the internal lobes inside the pump and as a result PD blowers are much less tolerant of dirt in the gas stream. Therefore, PD stations include inlet dirt filtration to 50 micron. PD blowers cannot generate high suction, which causes them to overheat and potentially fail. They can generate back pressure up to 100 millibar (gauge) = 100Pg (gauge) (mbarG); however, this may not be sufficient for transporting gas over distances > 50 m or for utilization for power generation. Figure 8 shows a cross section of a PD blower.

Figure 8. PD Blower Cross Section



With no requirement for a water seal, the drained gas from PD blowers contains far less water than gas from LRVPs. Typically, the relative humidity (RH) of gas from a PD blower is less than 20%. Depending on the duty (suction) of the pump, the exhausting gas can be hot (60–120^{o}C), and therefore would require cooling before utilization.

Table 4. Comparison of LRVP and PD methane extraction stations

Parameter	Liquid Ring Vacuum Pump station	Positive Displacement blower station
Plant automation	No automatic control or safety systems; modification required to enable safe utilization.	Fully automatic control; very little modification required to enable safe utilization.
Drained gas water content	High: Water is carried over from the pump, hence 100% RH and entrained water droplets.	Low: No water carryover from the pump, only water from the drainage source is present as vapor.
Drained gas dirt content	Dirt will be carried over through the pump, levels of dirt will depend on the drainage type. Dirt filtration prior to utilization will be necessary.	Dirt is filtered at the inlet to the pump, possible requirement for additional dirt filtration before engine, dirt levels in gas will be less than LRVP.
Drained gas temperature	40 – 70^{o}C. Warm gas will require some cooling, this would form an integral part of the water removal process.	60 – 120^{o}C. Hot gas will certainly require cooling before utilization; this may cause condensation of water vapor.
Gas pre-treatment requirements	Comprehensive gas cooling, coalescing and filtration to condense vapor, filter out water droplets and dirt particles before utilization.	Basic gas cooling and filtration before utilization.

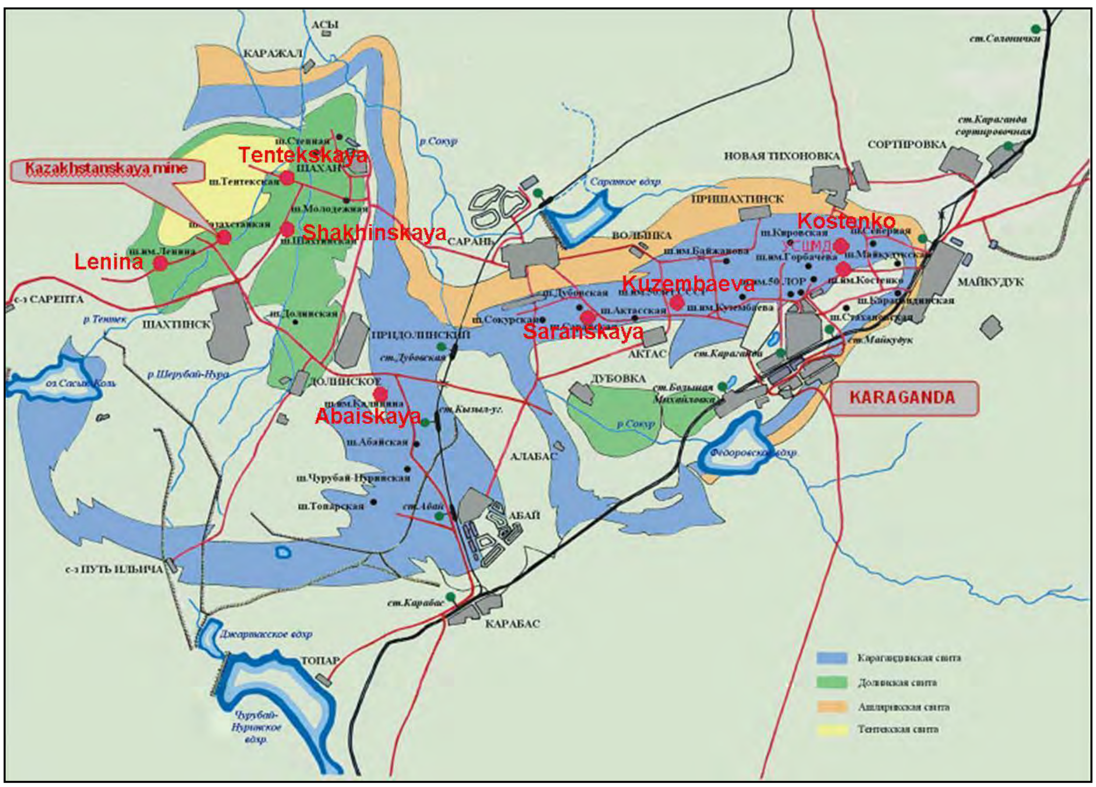
Table 4. Comparison of LRVP and PD methane extraction stations

Parameter	Liquid Ring Vacuum Pump station	Positive Displacement blower station
Drained gas delivery pressure	Back pressure between 200 – 300mBarG must be generated to maintain effective operation of the pump. This pressure can be used to send gas over medium distance for utilization without booster pumps.	Back pressure of only 100 mbarG can be generated; this may require the installation of additional booster pumps to send gas over medium distance for utilization.

4.3 Distribution of High Concentration Gas Sources

The AM sources of high concentration drained methane are distributed over a large area of around 3,000 square km (Figure 9). Thus, the distributed location of the six coal mines and the further distribution of multiple extraction plants on the surface of each mine mean that it is not feasible from an infrastructure perspective to install a single central generating plant.

Figure 9. Regional map showing location of mines



Instead of a single central generating plant, each mine would require its own power plant. Where high concentration gas is being drained by multiple sources at one mine, those sources should be connected using a gas pipe grid. Appendix A details the individual gas resource analysis, which is used to develop the recommended initial installed power capacity presented in Table 5. This summary is presented in units of MWe based upon the quantity of electricity that can be produced with an availability of 95%. The net energy production is estimated to be 19 MWe. The 19 MWe generating capacity is a 36% reduction from the average gas resource, giving an overall gas utilization factor of 64%.

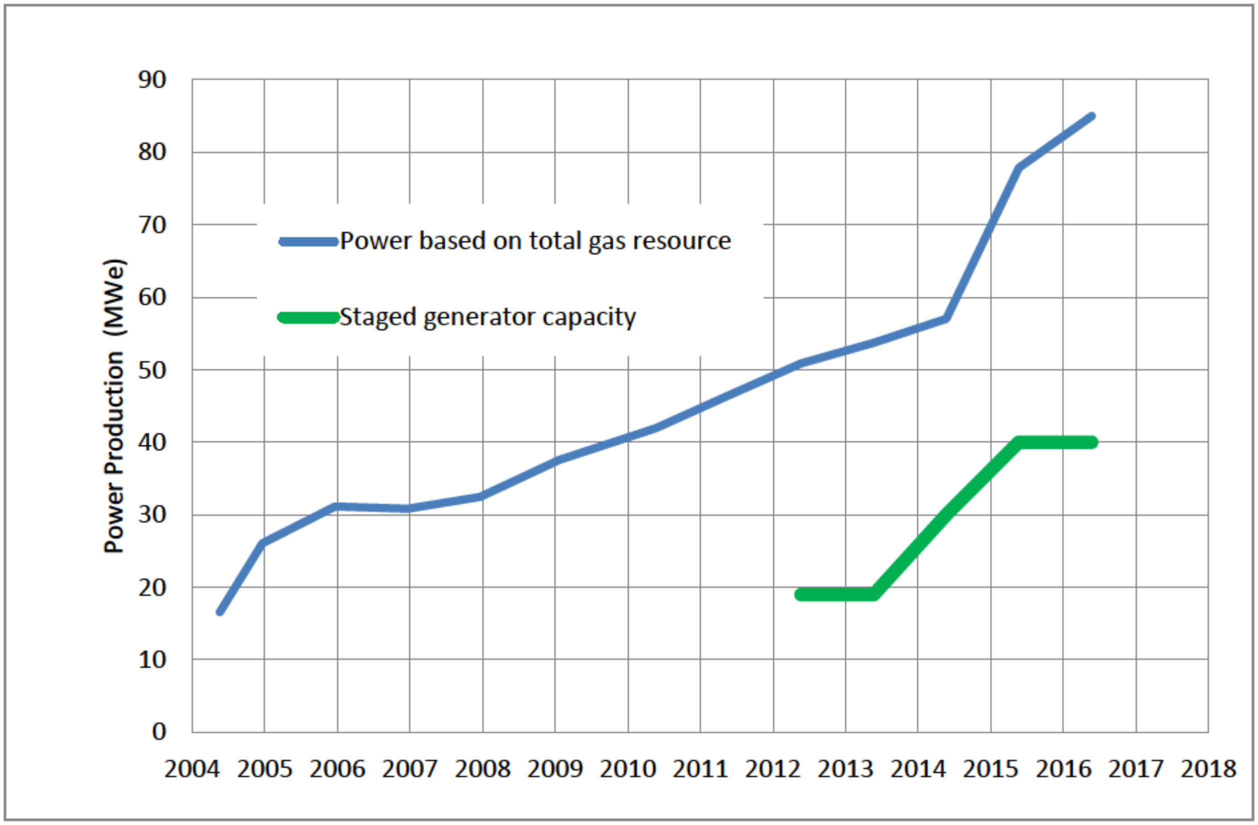
Table 5. Summary of Individual Mine Gas Resource Availability

Mine	Power Plant Location	Initial Installed capacity (MWe)
Kuzembaeva	BHC 95	3
Saranskaya	BHC 31	2
Abayskaya	Central	8
Kazakhstanskaya	Skip Shaft	2
Lenina	VFVS	3
Tentekskaya	Central W	1
		19

4.4 Future Projection of Utilization Project Size

The blue curve in Figure 10 shows the potential power production if all CMM were used to generate electricity.

Figure 10. Average gas resource trend



4.5 Phasing of Power Generation

An effective method to capitalize on an increasing projected gas resource is to split a CMM project into phases. The modular nature of reciprocating gas generator sets suitable for utilizing CMM means that it is easy and cost effective to increase the capacity of an installed power plant by simply installing additional generator modules.

The green curve in Figure 10 demonstrates the development of a power generation project in two phases that are sized to maintain at least 95% project availability. Phase 1 would be sized based on accurate drainage data through 2009 and sized conservatively at 19 MWe. The timing of phase 2 would be approximately 2 years from the start of implementation of phase 1 and sized for an additional 21 MWe (providing gas production measurements continue to track the resource projection of Figure 10 as shown with the blue curve).

Typically, the initial phase would take 6 months to complete planning and final approval; followed by 12 months to manufacture, install, and commission the equipment. Then, 6 months would be allowed for accurately determining the additional gas resources available for a second phase. Phase 2 could be implemented by 2015. Based on projected data in Figure 10, the size of Phase 2 could be an additional 21 MWe to bring the total project size to 40 MWe. Table 6 summarizes the project phasing.

Table 6. Phasing of power generation

2009	2010	2011	2012	2013	2014	2015
Historical data analysis from 2004 – 2009 shows Phase 1 should be sized at 19 MWe			Phase 1 commercial development, order equipment	Install Phase 1 and operate as generation is commissioned	Phase 2 order equipment and install, operate as generation is commissioned	Phase 2 in full operation
Projected year end capacity>>			0 MWe	19 MWe	30 MWe	40 MWe

The individual coal mine contributions to the overall project installed capacity are summarized in Table 7.

Table 7. Contribution of each mine to Phases 1 and 2

	Phase 1 Installed capacity (MWe)	**Phase 2 Installed capacity (MWe)**	**Total Installed capacity (MWe)**
Kuzembaeva	3	4	7
Saranskaya	2	10	12
Abayskaya	8	3	11
Kazakhstanskaya	2	0	2
Lenina	3	3	6
Tentekskaya	1	1	2
Total	**19**	**21**	**40**

5.0 COST BASIS FOR THE ECONOMIC ASSESSMENT OF A POWER GENERATION PROJECT

5.1 Capital Costs

Generating sets constitute the major cost of the proposed power generation project. The lowest cost option is to procure bare generating sets from manufacturers. Bare generating sets comprise a gas engine, synchronous AC alternator, AVR, and radiator on a skid mounted package, with a gas engine panel, generator controller in a separate panel. The generator skids are then installed in a permanent building complete with weather protection, ventilation, water cooling systems, and safety systems. However, the extraction of CMM gas resource across a mining group can be unpredictable, and frequently require the relocation of generating sets to extraction stations where the gas quantities and qualities meet the needs of the generating sets. Therefore, containerized packaged generators, though more expensive, are considered a superior solution and were used in the economic assessment.

The additional major cost items for this project are as follows:

- Gas transportation pipeline
- Gas compression system
- Gas holder acting as a manifold for CMM collection and concentration blending
- Gas treatment system
- Reciprocating gas engine-generator set, containerized
- Electrical connection equipment

The project encompasses six coal mines, therefore the cost estimate focuses on the largest value items for which the greatest uncertainty lies, i.e., the generator unit procurement. The following sections describe the equipment specified for each major infrastructure component.

5.2 Gas Transportation Pipeline

A detailed cost estimate was conducted for the Kazakhstanskaya Mine CMM drainage design and collection system. The cost details for this design were then used as the basis for a pro-rata estimate across the other five coal mine power plants.

5.3 Gas Compression System

Each of the methane extraction stations is designed to maximize gas extraction and therefore is unable to deliver gas at the pressures required for transportation without affecting suction pressure. The methane extraction stations are typically able to deliver gas at pressures between 0 BarG and 0.1 BarG without affecting suction pressure. Because there are several methane extraction stations in each coal mine power plant gas grid, it is more cost effective to install one gas compression system at the power generation plant than to install a separate gas compressor system at each methane extraction station. The cost of the gas compressor system at the Lenina CMM project was used to estimate the cost of compressor systems for this analysis.

5.4 Gas Holder Acting as Manifold for CMM Collection and Concentration Blending

Because the gas is coming from several methane extraction stations, with varying qualities, it is necessary to blend the various sources to provide a more stable gas resource. This blending is achieved in a gas holder, installed after the gas compression system and prior to the gas treatment system. The gas holder acts as a mixing tank to smooth out gas pressure and quality. The gas holder also ensures that gas transport velocity is reduced, allowing water and solids to drop out, thereby minimizing loading on the gas treatment system.

5.5 Gas Treatment System

The gas coming from the methane extraction plants will be wet and laden with particulates. However, the gas engine generator packages require dry and clean gas. The gas treatment system will remove water and filter the gas to ensure that engine operating conditions are met. One system should be installed per power plant site.

5.6 Engine Generator Set

The fuel will be relatively variable in concentration and flow rate, therefore it is necessary to select reciprocating engines capable of this type of modulation. For the gas flow and power outputs required, it is necessary to size units in the 1 to 2 MWe range. The units need special coal mine methane gas modulation/mixing valves to cope with fast changing gas quality.

Equipment suppliers with local Kazakhstan distributors were contacted to obtain a range of prices for engine generator sets. The prices used in this analysis represent an average cost based on the mean of the three suppliers that provided pricing. The same approach was used to obtain operation and maintenance cost estimates.

5.7 Electrical Connection

The pilot project at Lenina mine provided a solid cost basis for estimating electrical connection costs associated with a larger scale project. These costs were based on actual costs from this project, projected on a pro-rata basis per MW installed.

5.8 Waste Heat Recovery

The project design specified for this analysis does not include waste heat recovery. Although waste heat recovery is the recommended system design, waste heat recovery systems will be very site specific. They will vary for each site, based on the heat loads of the site and the current energy prices being paid by the site. As a result, addressing waste heat recovery is not practical for the purposes of this study, but should be a component of the full feasibility study that would be conducted if AM decides to proceed with developing a project.

5.9 Summary of Economic/Engineering Inputs into a Cash Flow Model

A standard discounted cash flow model was used to evaluate the economic performance of the two CMM power project phases discussed in the previous section for the six AM mines. The key economic parameters used in the discounted cash flow model are presented in Table 8.

Table 8. Input parameters for the discounted cash flow model

Parameter:	units	value
2011 power price	$(USD)/MWh	50.00
Rate of inflation for power	% pa	11.4
Rate of inflation for O&M	% pa	7.4
Tax rate	% pa	15.0
Discount rate for NPV	% pa	10.0
Engine Capacity Factor	% pa	75.0

The $50.00/MWh power price for 2011 was provided by the AM, based on local Kazakh rates. The 7.4% general inflation rate for O&M is based on the average general inflation rate for Kazakhstan from 2002 through 2009 (except for 2007, considered an outlier)[1]. The 11.4% expected rate of inflation for the power price is based on past performance relative to the general inflation rate for Kazakhstan from 2002 through 2009 (except for 2007, considered an outlier)[1]. The Kazakhstan tax rate is an assumed income tax rate on profits, based on typical rated experienced across Europe. The 10% discount rate for the time value of money is a generally accepted value for safe corporate investments in the current global market. Engine capacity factor accounts for the fraction of time that the gas collection system and power generation equipment will be offline due to infrastructure, climatic and maintenance factors.

The capital cost of the proposed project is detailed in Table 9. The power plant sizes and locations were presented in Table 5. Because this is a pre-feasibility study, the costs are estimates only and are not based on detailed bid values solicited from suppliers for this specific project recommendation. The costs for operating and maintaining the generating equipment were also obtained from the engine suppliers when obtaining the capital cost estimates. The O&M costs are presented in the form of an O&M fee per kilowatt hour of electricity generated ($/kWh) that is paid to an O&M contractor. This is standard industry practice as it incentivizes the O&M contractor to maximize power generation. The O&M rate used in the economic analysis of this study is $0.01377/kWh; which is the mean of three quotations that were obtained during the budgetary tendering exercise. This rate includes for the cost of a major engine overhaul, which is typically required every 60,000 hours of operation and thus represents the true lifecycle O&M cost of the project.

[1] Electricity tariffs, power sector modernization and energy efficiency investments. http://kazseff.kz/Downloads/Article_Development_of_power_tariffs_in_Kazakhstan_eng.pdf

Table 9. Project capital costs

Project CAPEX Estimate	**Cost (USD)**
Project Management (two phases)	$450,000
Design	$150,000
Design Institute	$3,000,000
Safety Institute	$50,000
Phase 1 Power Generation 19 MWe	$13,919,345
Phase 2 Power Generation 21 MWe	$15,384,539
Gas Transport	$15,000,000
Grid Connection for 6 sites	$6,060,000
CAPEX Total for Phase 1 & 2	**$54,013,885**
CAPEX Phase 1	$38,629,345
CAPEX Phase 2	$15,384,539

6.0 PRELIMINARY ECONOMIC FEASIBILITY ANALYSIS

6.1 Results of Economic Analysis

The results of the discounted cash flow analysis are shown in Table 10. Table 11 presents the summary financial performance parameters. The cumulative cash flow becomes positive in the 5th year and results in a 10 year return on investment of 13.3%.

Table 10. Discounted cash flow analysis

Cost Components (USD)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
CAPEX Outlay ($k)	(38,629)		(15,384)							
Power capacity installed (MWe)	-	19.0	30.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
Revenue from power ($k)	-	6,473	11,386	16,912	18,840	20,988	23,381	26,046	29,015	32,323
Operational cost ($k)	-	(2,309)	(3,916)	(5,608)	(6,022)	(6,468)	(6,947)	(7,461)	(8,013)	(8,606)
Taxable profit ($k)	-	4,164	7,470	11,305	12,818	14,520	16,434	18,585	21,002	23,717
Tax payable ($k)	-	(625)	(1,121)	(1,696)	(1,923)	(2,178)	(2,465)	(2,788)	(3,150)	(3,558)
Free cash flow to the firm ($k)	-	3,026	5,942	9,136	10,709	12,132	13,733	15,532	17,554	19,825
Nat cash flow ($k)	**-$38,629**	**$3,026**	**-$11,804**	**$9,136**	**$10,709**	**$12,132**	**$13,733**	**$15,532**	**$17,554**	**$19,825**
Cumulative net cash flow ($k)	**-$38,629**	**-$35,603**	**-$47,407**	**-$38,271**	**-$27,562**	**-$15,430**	**-$1,697**	**$13,835**	**$31,389**	**$51,214**

Table 11. Financial summary

NPV (10% discount rate)	$7,634,000 (USD)
10 yr IRR (Equity financed)	13.3%
Project payout, years	6

6.2 Sensitivity Analysis

There is considerable uncertainty in three of the input variables: capacity factor, power price inflation, and the Kazakhstan tax rate. Therefore, a sensitivity analysis was conducted on these three variables to test the economic results of one of the extreme values occurring.

The ranges of uncertainty used in the sensitivity analysis for gas availability, power price inflation, and the Kazakhstan tax rate are based on experience with similar projects in the region. The ranges of values chosen for these three parameters are shown in Table 12.

Table 12. Parameters for sensitivity analysis

Economic favorability of parameter	Capacity Factor	Power Price Inflation	Tax rate
Mid range	75.0%	11.4%	15.0%
Low Favorability	55.0%	9.4%	20.0%
High favorability	95.0%	13.4%	10.0%

In Table 12, the 'low economic favorability' value for the tax rate is the high tax rate, while the reverse is true for the capacity factor and the power price inflation.

The baseline case occurs when the mid value of all variables are used in the discounted cash flow calculations. The sensitivity to each variable can be demonstrated by applying the low to high values of a variable while retaining the baseline case value for the other two variables. The results of this analysis for NPV and IRR are summarized in Tables 13 and 14, respectively.

Table 13. Results of the sensitivity analysis on NPV ($k USD)

Economic favorability of parameter	Capacity Factor	Power Price Inflation	Tax rate
Mid range	$7,634	$7,634	$7,634
Low Favorability	-$7,322	$233	$4,229
High favorability	$22,589	$15,792	$11,038

Table 14. Results of the sensitivity analysis on IRR (%)

Economic favorability of parameter	Capacity Factor	Power Price Inflation	Tax rate
Mid	13.3%	13.3%	13.3%
Low	6.5%	10.1%	11.9%
High	19.1%	16.4%	14.7%

Diagrammatic representations of the sensitivity analysis are shown in Figures 11 and 12.

Figure 11. Results of the sensitivity analysis on NPV ($k USD)

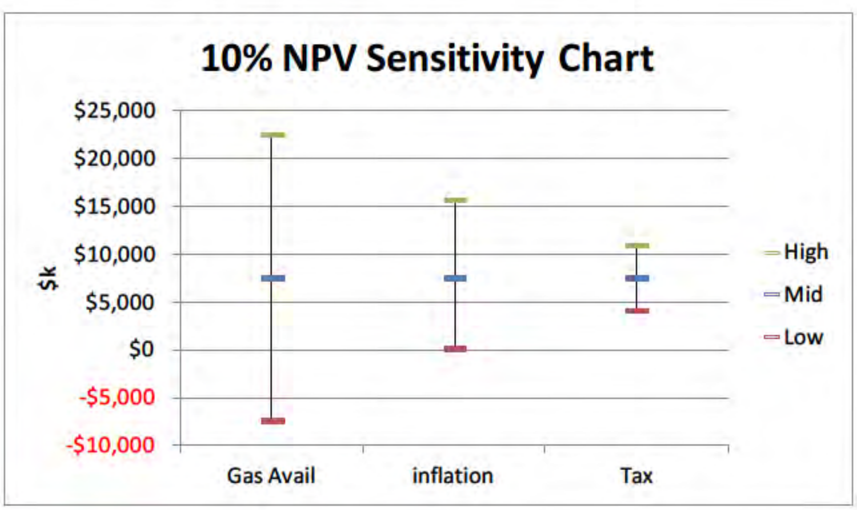
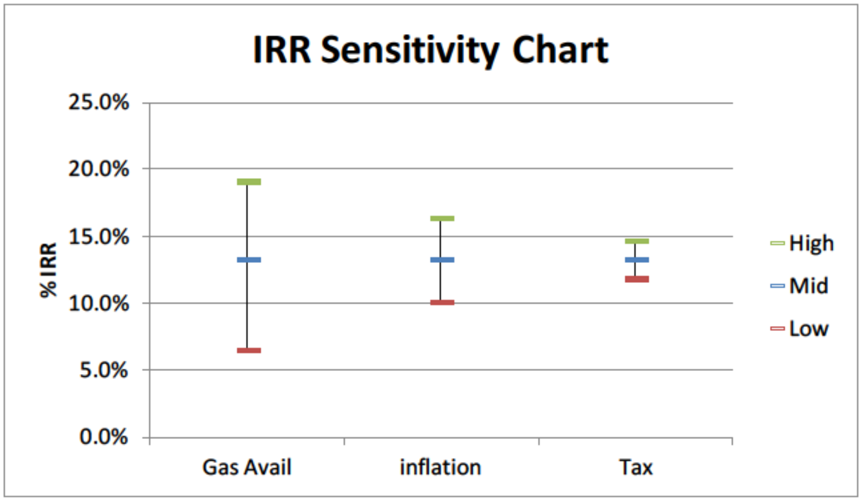


Figure 12. Results of the sensitivity analysis on IRR (%)



The sensitivity analysis shows that the project economics are most sensitive to the capacity factor of the combined gas collection system and the power generation sets. Everything that the plant can do to keep equipment in top operating condition and to keep the gas quality within the optimum range for the engines will greatly affect the economic performance of the system. The project was less affected by inflation and tax rate uncertainties, with the latter having little affect on economic performance.

Another way to analyze a project's sensitivity to various parameters is through Monte Carlo simulation. Triangular probability density functions are used in the sensitivity analysis to assess the sensitivity of the project to the three key parameters: capacity factor, power price inflation, and the Kazakhstan tax rate. Table 15 shows the probability density values assumed for each key parameter.

Table 15. Monte Carlo simulation probability distributions

	Probability				
Key parameter	Min	Mean	Max	5th percentile	95th percentile
Power price inflation rate, % pa	9%	11%	13%	10%	13%
Tax rate	10%	15%	20%	12%	18%
Gas availability	55%	75%	95%	61%	89%

The probability distributions are randomly sampled and used in the discounted cash flow spreadsheet to test random combinations of the three key parameters. This sampling was performed 5000 times for this analysis. The resulting values of NPV and IRR are then combined in a probability density function that can then be displayed as a cumulative probability function as shown in Figures 13 and 14 for NPV and IRR, respectively.

Figure 13. Cumulative probability for NPV

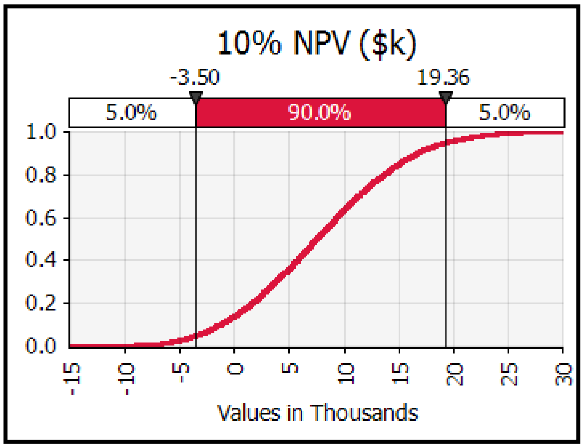
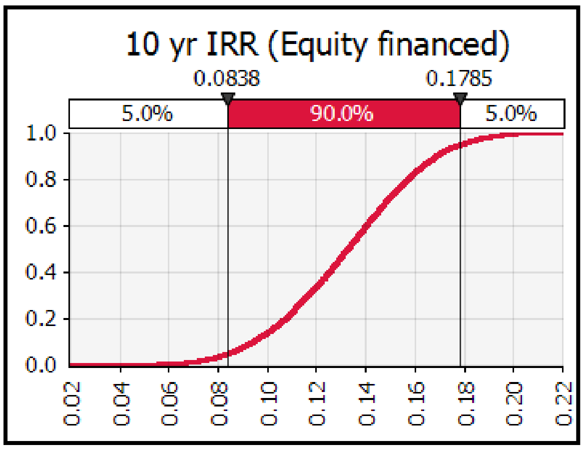


Figure 14. Cumulative probability for IRR



Based on this analysis there is an 85% probability that the project will provide a positive 10% NPV and an 80% probability that the 10% NPV will exceed $2 million (USD). Similarly, there is an 85% probability that the IRR will meet or exceed the 10% discount rate and an 80% probability that the IRR will exceed 11%. As mentioned previously, the mean probability (i.e. 50%) is for a NPV (10% discount rate) of $7,634,000 (USD) and an IRR of 13.3%.

6.3 Inclusion of Carbon Credits within Analysis

Carbon credits for the reduction of methane emissions have not been included in this economic analysis, up to this point. The future price of carbon and whether or not this project will qualify as an emission offset project is very uncertain. The year 2012 was the last year for qualifying emission reduction offset projects under the Clean Development Mechanism (CDM), and this project was unable to qualify before the end of the year for UNFCCC administrative reasons. The project may qualify under a voluntary emission reduction program such as the Verified Carbon Standard (VCS), however the price of voluntary carbon offsets is currently only about $2/tCO_2e$. Should carbon prices return to previous levels they would have a significant impact on the profitability of the project. The following analysis shows the effect of a modest carbon price of $10/tCO_2e$ on project economic performance in Tables 16-18.

Table 16. Input parameters for carbon credit analysis with the discounted cash flow model

Parameter:	units	value
2011 power price	$ (USD)/MW.hr	50.0
Rate of Inflation for power	% pa	11.4
Rate of Inflation for O&M	% pa	7.4
VER carbon price	$ (USD)/tonne	10.0
KZ tax rate	% pa	15.0
Discount rate for NPV	% pa	10.0
Engine Capacity Factor	% pa	75.0

Table 17. Financial summary

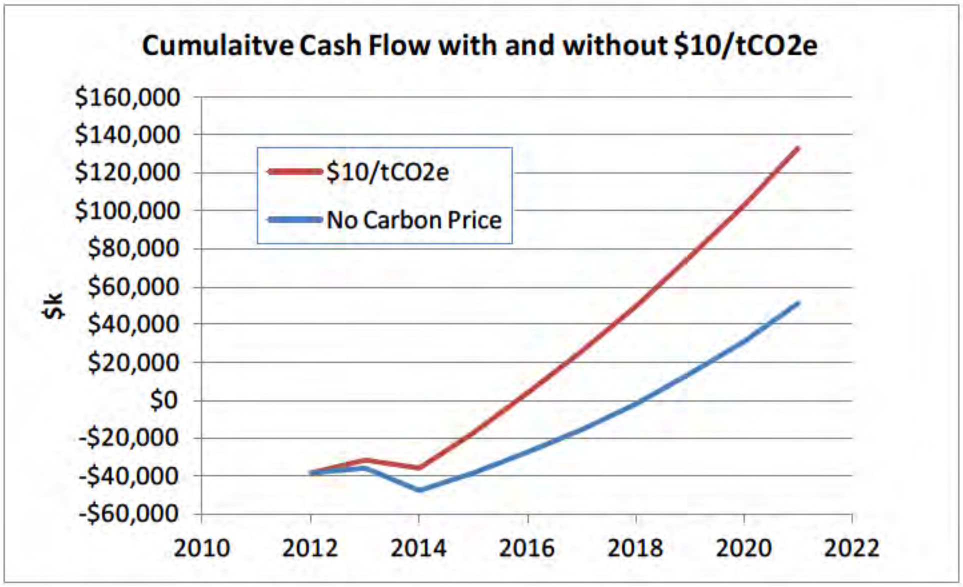
NPV (10% discount rate)	$53,336,000 (USD)
10 yr IRR (Equity financed)	30.9%
Project Payout, years	4

Table 18. Discounted cash flow analysis

Cost Components (USD)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
CAPEX Outlay ($k)	(38,629.3)		(15,384.5)							
Power capacity (MWe)	-	19.0	30.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
Revenue from power ($k)	-	6,473.3	11,386.1	16,912.2	18,840.2	20,988.0	23,380.6	26,046.0	29,015.3	32,323.0
Revenue from carbon ($k)	-	5,672.6	8,958.6	11,942.4	11,942.4	11,942.4	11,942.4	11,942.4	11,942.4	11,942.4
Total revenue ($k)	-	12,145.9	20,344.7	28,854.6	30,782.6	32,930.4	35,323.0	37,988.4	40,957.7	44,265.4
Operational cost ($k)	-	(2,309.2)	(3,915.9)	(5,607.5)	(6,022.5)	(6,468.2)	(6,946.8)	(7,460.9)	(8,013.0)	(8,605.9)
Taxable profit ($k)	-	9,836.7	16,428.9	23,247.1	24,760.1	26,462.2	28,376.2	30,527.6	32,944.7	35,659.5
Tax payable ($k)	-	(1,475.5)	(2,464.3)	(3,487.1)	(3,714.0)	(3,969.3)	(4,256.4)	(4,579.1)	(4,941.7)	(5,348.9)
Free cash flow to firm ($k)	-	7,148.5	13,151.8	18,919.4	20,859.6	22,283.1	23,883.8	25,683.2	27,705.0	29,975.9
Net cash flow ($k)	**-$38,629**	**$7,148**	**-$4,594**	**$18,919**	**$20,860**	**$22,283**	**$23,884**	**$25,683**	**$27,705**	**$29,976**
Cumulative cash flow ($k)	**-$38,629**	**-$31,481**	**-$36,075**	**-$17,155**	**$3,704**	**$25,987**	**$49,871**	**$75,554**	**$103,259**	**$133,235**

A price for carbon mitigation makes a very large difference in project economic performance, especially regarding the time that the project can recover its cost as shown below. A $10/tonne CO_2e price would reduce the payout time from 6 years to 4 years, increase the NPV by more than $45 million, and increase the IRR from 13.3% to 30.9%, making a marginal project an economically viable project. The impact of carbon credits on the cash flow of the project is presented in Figure 15.

Figure 15. Effect of carbon credits on project cash flow



7.0 CONCLUSIONS

Based on a technical and commercial evaluation, power generation using reciprocating gas engines with waste heat recovery is recommended at AM mines where a heat load exists, and power generation using simple reciprocating engines without heat recovery is recommended where no heat load exists. Current infrastructure and market constraints limit the practicality of employing other types of projects for the use of CMM from the AM mines.

The relatively large distances between extraction stations limit the technical and commercial viability of a centralized generating plant serving all of the AM mines. Though a centralized generating plant may be lower cost on an installed $/MWh basis, the cost and technical challenge of transporting the gas to a centralized plant is prohibitive. The variable nature of the CMM gas flow and quality means that individual methane extraction stations cannot sustain their own individual generating plants. However, combining the gas delivered from several extraction stations to power a central generating plant at each mine resolves these issues. Although gas transportation will still be necessary with a central mine generating station, the distances involved are substantially shorter and more manageable. Developing the project in phases will reduce the economic risk of the project. The first phase would be based on a conservative assessment of current gas flow rates, and a second phase would be based on the performance of the first phase and proven CMM flow rates as the mines expand operations.

While an electric project appears commercially viable, there are economic risks resulting from the variable gas resource. There is some uncertainty associated with the flow and quality of the CMM resource. This risk can be mitigated by manifolding gas from multiple extraction stations to a central mine power generation plant, and by using semi-mobile containerized generators that can be reallocated to optimize the gas use across all AM mines. However, the high investment cost of these generators, mean that the project IRR hurdle rate needs to be higher than a straightforward infrastructure project to incentivize project execution. On this basis it would be very beneficial for the project to receive carbon finance revenue from carbon prices stronger than the current price to enable investment.

Recommendations

It is recommended that ArcelorMittal conduct a full economic feasibility analysis of an electric power generation project for the six mines investigated in this report that is based on the most up to date mining plans and actual contract prices for gas pipelines, power generation equipment, and site construction/installation. The full economic analysis would optimize the number, size and location of the power generating plants and evaluate the sites where combined heat and power may be economically attractive.

It is also recommended that the project owner investigate the current strategy of the Kazakhstan Government regarding climate change regulation and carbon emissions reduction mechanisms. The project owner should investigate whether this project can be assisted by any national incentives provided by these future strategies. In parallel with this activity the project owner should investigate voluntary emission reduction mechanisms to determine whether carbon revenue can be generated from these sources. If additional incentives are identified, they may also change the results of the project options analysis discussed in Section 3.0 of this report and the full feasibility study should reinvestigate these options.

Appendix A

Projected CMM and VAM Data

Projected CMM and VAM data in Tables A-1 and A-2 were provided by Mr. Aleksandr Polchin, Gas Control Manager, AM Coal Division for six mines: Kuzembayeva, Saranskaya, Abayskaya, Kazakhstanskaya, Lenina and Tentekskaya.
Table A-1 shows future projections of drained methane average flow and average concentration of coal mine methane for each mine between 2012-2015. Table A-2 presents ventilation air methane concentrations for various mine shafts.

Table A-1. Projected CMM and VAM Data

Mine Longwall	Total methane release m^3/min	Ventilation m^3/min	Degassing m^3/min	Average methane concentration, %	Type of degassing
Kuzembayeva mine					
2012 – 33 $К_7$-w	44,0	15,0	29,0	25,0	HEL
2013 - 34 $К_7$-w	44,0	15,0	29,0	25,0	HEL
2014 – 37 $К_{10}$-e	88,0	16,0	72,0		
			5,0	10,0	seam.
			58,0	40,0	Gas dra.$К_{11}$
			9,0	6,0	v.heel
2015 – 41 $К_{10}$-w	90,0	16,0	74,0		
			5,0	10,0	seam.
			58,0	40,0	Gas dra.$К_{11}$
			9,0	6,0	v.heel
Saranskaya mine					
2012 - 61 $К_{12}$-e	56,0	12,0	44,0		
			5,0	10,0	seam.
			9,0	6,0	v.heel
			30,0	27,0	connection
2013 – 51 $К_7$-w	63,0	36,0	27,0	25,0	connection
2014 – 71 $К_{10}$-W	110,0	15,0	95,0		
			5,0	10,0	seam.
			60,0	50,0	Gas dra.$К_{11}$
			30,0	25,0	connection
2015 – 50 $К_{10}$-e	110,0	15,0	95,0		
			5,0	10,0	seam.
			60,0	50,0	Gas dra.$К_{11}$
			30,0	25,0	Connection
Abayskaya mine					
2012 – 33 $К_{10}$-N	141,0	17,0	124,0		
			10,0	15,0	seam.
			90,0	55,0	Gas dra.$К_{11}$
			24,0	8,0	v.heel
2013 – 331 $К_{10}$-S	146,0	17,0	129,0		
			10,0	15,0	seam.
			95,0	55,0	Gas dra.$К_{11}$
			24,0	9,0	v.heel

Table A-1. Projected CMM and VAM Data

Mine Longwall	Total methane release m^3/min	Ventilation m^3/min	Degassing m^3/min	Average methane concentration, %	Type of degassing
2014 – 221 К$_{18}$-N	40,0	12,0	28,0		
			10,0	50,0	vert. hole
			18,0	10,0	connection
2015 - 211 К$_{10}$-S	110,0	17,0	93,0		seam.
					Gas dra.К$_{11}$
			5,0	15,0	v.heel
			78,0	56,0	
			10,0	7,0	vert. hole
2015 - 321 К$_{18}$-N	40,0	12,0	28,0		connection
			10,0	50,0	
			18,0	10,0	
Kazakhstanskaya mine					
2013 – 312 d$_6$-1w	69,0	20,0	49,0		
			4,0	15,0	seam.
			20,0	50,0	vert. hole.
			25,0	20,0	connection
2014 – 334 d$_6$-1e	76,0	20,0	56,0		
			5,0	15,0	seam.
			20,0	55,0	vert. hole
			31,0	20,0	connection
2015 – 324a d$_6$-1e	72,0	20,0	52,0		
			4,0	15,0	seam.
			20,0	55,0	vert. hole
			28,0	20,0	connection
2016 – 322 d$_6$-1w	78,0	20,0	58,0		
			5,0	15,0	seam.
			20,0	55,0	vert. hole
			33,0	20,0	connection
Lenina mine					
2012 – 402 d$_6$-1e	68,5	25,0	43,5		
			6,0	27,0	seam.
			25,0	40,0	vert. hole
			12,5	15,0	Inst. chamb.
2013 – 403 d$_6$-1w	68,5	25,0	43,5		
			6,0	27,0	seam.
			25,0	40,0	vert. hole
			12,5	15,0	Inst.chamb.
2014 – 401 d$_6$-1e	88,0	25,0	63,0		seam.
			6,0	27,0	vert. hole
			25,0	40,0	Gas dra.D7
			17,0	25,0	Inst.chamb.
			15,0	15,0	seam.
2015 – 402 d$_6$-1e	88,0	25,0	63,0		vert. hole

Table A-1. Projected CMM and VAM Data

Mine Longwall	Total methane release m^3/min	Ventilation m^3/min	Degassing m^3/min	Average methane concentration, %	Type of degassing
			6,0	27,0	Gas dra.D7
			25,0	40,0	Inst.chamb.
			17,0	25,0	
			15,0	15,0	
Tentekskaya mine					
2012 – 212 d_6-s	55,0	26,0	29,0		
			2,0	15,0	seam.
			15,0	35,0	vert. hole.
			12,0	15,0	connection
2013 – 222 d_6-s	73,0	26,0	47,0		seam.
			2,0	15,0	vert. hole
			25,0	50,0	connection
			20,0	15,0	vert. hole
2014 – 253 T_1-n	45,0	15,0	30,0		connection
			15,0	50,0	
			15,0	15,0	
					seam.
					vert. hole
2015 – 231A d_6-s	73,0	26,0	47,0		connection
			2,0	15,0	
			25,0	50,0	
			20,0	15,0	

The use of PD blowers should be considered only for gas transportation. The following PD blowers are recommended for gas transportation and delivery to the energy plant:

Kuzembayeva mine – 1 vacuum pump system (VPS) and 1780 meters of gas pipe lines with diameter of 402 millimeter (mm) (with satelite)
Saranskaya mine – 1 VPS and 2420 meters of gas pipe lines with diameter of 402 mm (with satellite)
Abayskaya mine – 1500 meters of gas pipe lines with diameter of 402mm (with satellite)
Kazakhstanskaya mine – 1 VPS and 1700 meters of gas pipe lines with diameter of 402mm (with satellite)
Lenina mine – none
Tentekskaya mine – 1 VPS and 2500 meters of gas pipe lines with diameter of 402mm (with satellite)

Table A-2. AM Coal Division Mines Ventilation Shafts VAM Profiles

Name of shaft	Maximum permitted gas concentration according to SR	Q, M^3/min	K, %	I, M^3/min
Kuzembayeva mine				**56,81**
1. Central ventilation shaft	**0,75**	12552	0,2	25,72
2. Western ventilation shaft	**0,75**	4406	0,3	13,22
3. Ventilation shaft No6	**0,75**	8935	0,2	17,87
Saranskaya mine				**79,45**
1. Skip shaft No1 (Saran district)	**0,75**	9709	0,1	9,71
2. Skip shaft No2 (Aktas district)	**0,75**	11694	0,45	52,62
3. Eastern ventilation shaft	**0,75**	6263	0,1	6,26
4. Western ventilation shaft	**0,75**	5432	0,2	10,86
Abayskaya mine				**106,76**
1. Skip shaft	**0,75**	906	0,1	0,9
2. Central ventilation pit-hole	**0,75**	14115	0,75	105,86
Kazakhstanskaya mine				**61,97**
1. Skip-coal shaft	**0,75**	742	0,1	0,74
2. 1st cage shaft	**0,75**	4023	0,2	8,05
3. Skip-rock shaft	**0,75**	996	0,1	1,0
4. Western side ventilation shaft	**0,75**	9130	0,3	27,39
5. Eastern side ventilation shaft	**0,75**	9915	0,25	24,79
Lenina mine				**97,33**
1. Pit hole No2	**0,75**	9069	0,1	9,07
2. Side ventilation shaft	**0,75**	6830	0,26	17,75
3. ventilation shaft of southern section	**0,75**	12820	0,55	70,51
Tentekskaya mine				**76,96**
1. Southern ventilation shaft	**0,75**	10163	0,27	27,44
2. Northern pit-hole No2	**0,75**	7415	0,65	48,20
3. Main incline shaft	**0,75**	1317	0,1	1,32

Appendix B

AM Ventilation Air Methane Project Assessment

Appendix B. AM Ventilation Air Methane Project Assessment

Current ventilation data were provided by AM for all up-cast ventilation shafts within the group of six mines covered by this study. Average airflow rate and methane concentration data have been provided. Shafts with a VAM concentration of less than 0.2% methane have been discounted from the study because it is not feasible to abate methane below this threshold with the technologies available on the market.

B.1 Modeling of emission reduction

A very preliminary cost analysis was conducted based on data provided by AM and use of a two can Regenerative Thermal Oxidizer. The assumptions made for the analysis are explained below:

B.2 Calculation of the number of units

An 80% capture factor was applied to the air exhaust rate from the shaft because it is not technically feasible to capture 100% of the VAM resource. The VAM capture hood system must be designed to allow ventilation air to pass freely to the atmosphere so that if the VAM units stop for any reason, there is no backpressure being put upon the mine ventilation fan. The 80% of total airflow was divided by the flow rate of a single oxidizer unit to estimate the required number of units. To be conservative, this number was rounded down to the nearest whole number.

The technical specifications of a typical regenerative thermal oxidizer VAM unit used for the analysis, were as follows:

- Flow rate: 90,000 Nm^3/hr (1,500Nm^3/min)
- Parasitic load: 150 kWe
- Destruction efficiency: 97%
- Minimum auto-thermal VAM concentration: 0.2% CH_4

B.3 Consistency of VAM gas resource

The flow and concentration of VAM emitted from the coal group are expected to be very consistent over time based on the method of releasing gas from old workings employed by AM. Mined out areas are sealed off from the ventilation circuit by explosion-proof stoppings. These stoppings have pipes through them that enable gas from the mined out area to bleed into the ventilation circuit. This prevents any pressure build up that could cause gas to migrate in an uncontrolled manner. The methane bled from these stoppings provides a consistent supply of VAM as it represents a greater contribution than the gas from the working face. All the coal mines within the group of six mines are more than 60 years old with large quantities of coal having been extracted, resulting in large amounts of mined out areas to support consistent VAM emissions to level out VAM fluctuations caused by gaps in coal production. As a result, a realistic equipment availability of 95% has been used in the analysis. Table B-1 summarizes the analysis and Table B-2 shows all data analysis.

Table B-1. Summary of VAM Analysis

Mine name	Number of units	Annual emission reduction (tCO_2)
Kuzembaeva mine	12	213,861
Saranskaya mine	8	261,477
Abayskaya mine	7	449,561
Kazakhstanskaya mine	11	236,640
Lenina mine	9	345,710
Tentekskaya mine	8	278,877
	Total:	**1,786,126**

Table B-2. VAM Resource Table and Mitigation Analysis

Name of mine and shaft	Shaft airflow rate (m^3/min)	VAM concentration (%CH_4)	Number of VAM units (each rated at 1500 m^3/min)	Annual CO_2e reduction (tonnes CO_2e)
Kuzembayeva mine				
1. Central ventilation shaft	12552	0.2	6	98,230
2. Western ventilation shaft	4406	0.3	2	50,144
3. Ventilation shaft No6	8935	0.2	4	65,487
Saranskaya mine				
1. Skip shaft No1 (Saran district)	9709	0.1	N/A	-
2. Skip shaft No2 (Aktas district)	11694	0.45	6	228,734
3. Eastern ventilation shaft	6263	0.1	N/A	-
4. Western ventilation shaft	5432	0.2	2	32,743
Abayskaya mine				
1. Skip shaft	906	0.1	N/A	-
2. Central ventilation pit-hole	14115	0.75	7	449,561
Kazakhstanskaya mine				
1. Skip-coal shaft	742	0.1	N/A	-
2. 1st cage shaft	4023	0.2	2	32,743
3. Skip-rock shaft	996	0.1	N/A	-
4. Western side ventilation shaft	9130	0.3	4	100,288
5. Eastern side ventilation shaft	9915	0.25	5	103,609

Lenina mine				
1. Pit hole No2	9069	0.1	N/A	-
2. Side ventilation shaft	6830	0.26	3	64,775
3. ventilation shaft of southern section	12820	0.55	6	280,935
Tentekskaya mine				
1. Southern ventilation shaft	10163	0.27	5	112,309
2. Northern pit-hole No2	7415	0.65	3	166,568
3. Main incline shaft	1317	0.1	N/A	-
			Total tCO_2e reduction:	**1,786,126**

Using typical installation pricing, the CAPEX cost is estimated to be $48 million (USD). Using a current VER price of $2 per tonne, estimated revenues approach $3.6 million per annum for carbon only. Additional revenues from waste heat avoiding on-site coal use cost would be negligible. On this basis, until Kazakhstan sets up its own carbon mitigation scheme to provide financial incentives, VAM mitigation is not commercially viable.

Appendix C

Geological and Production Data for AM Mines

C.1 Overview of AM Mining Operations

ArcelorMittal (AM) owns and operates eight underground coal mines located in the Karaganda coal basin:

Kostenko Mine
Kuzembaeva Mine
Saranskaya Mine
Abayskaya Mine
Kazakhstanskaya Mine
Lenina Mine
Shakhtinskaya Mine
Tentekskaya Mine

Regionally the mines of ArcelorMittal Temirtau JSC, Coal Division are located in the territory of the Karaganda Coal Basin. Mining is ongoing in three production areas:

Area 1: Karagandinskiy – Kostenko Mine, Kuzembaeva Mine, Saranskaya Mine
Area 2: Sherubay-Nurinskiy – Abayskaya Mine, Shakhtinskaya Mine
Area 3: Tentekskiy – Kazakhstanskaya Mine, Lenina Mine and Tentekskaya Mine

The Kostenko Mine was put in operation in 1934. During World War II the mine operated on the basis of temporary schemes. It was re-commissioned in 1952 and was merged with No86/87 Mine in 1968. In 1996 the mine was acquired by Ispat-Karmet JSC, Coal Division (now ArcelorMittal Temirtau JSC, Coal Division) and in 1998 it merged with neighboring Stakhanovskaya mine. The field of Kostenko mine territorially belongs to Oktyabrskiy district of Karaganda city.

The Kuzembaeva Mine was established in 1998 by the merging of Kuzembaeva Mine and the 50th Anniversary of USSR Mine. In 1996, the mine was acquired by Ispat-Karmet JSC, Coal Division (now ArcelorMittal Temirtau JSC, Coal Division). The nearest communities are Saran, Abay, and Shakhtinsk towns that are located 18 km to the northeast, 15 km to the southeast and 12 km to the west from the site, respectively. The eastern part of the mine field territorially belongs to the regional centre - Karaganda City.

The Saranskaya mine was put in operation in 1955, and reconstructed between 1968 and 1974. In 1996 the mine was acquired by Ispat-Karmet JSC, Coal Division (now ArcelorMittal Temirtau JSC, Coal Division). It was merged with Sokurskaya Mine in the middle of 1997 and Aktasskaya Mine in 1998. The nearest communities are Saran, Abay, and Shakhtinsk towns that are located 18 km to the northeast, 15 km to the southeast and 12 km to the west from the site, respectively. The regional centre, Karaganda City, is located some 35km to the northeast.

The Abayskaya mine was put in operation in 1961. In 1996 the mine was acquired by Ispat-Karmet JSC, Coal Division (now ArcelorMittal Temirtau JSC, Coal Division) and merged with Kalinina Mine. The nearest communities are Saran, Abay, and Shakhtinsk towns that are located 18 km to the northeast, 15 km to the southeast and 20 km to the west from the site, respectively. The regional centre, Karaganda City, is located some 30 km to the northeast.

The Kazakhstanskaya Mine was put into operation in 1969. In 1996, the mine was acquired by Ispat-Karmet JSC, Coal Division (now ArcelorMittal Temirtau JSC, Coal Division). The nearest community is Shakhtinsk town that is located 7 km to the southeast of the site and the regional centre, Karaganda City, is located about 50km to the northeast. The railway station at MPS-Karabas is located about 35km away to the southeast.

The Lenina mine was put into operation in 1964 and was subsequently merged with Naklonnaya No1/2 mine in 1968. In 1996 the mine was acquired by Ispat-Karmet JSC, Coal Division (now ArcelorMittal Temirtau JSC, Coal Division). The nearest community is Shakhtinsk town that is located 7 km to the southeast of the site and the regional centre, Karaganda City, is located 50 km to the northeast. The railway station MPS-Karabas is located 35 km to the southeast.

The Shakhtinskaya mine was put in operation in 1973. In 1996, the mine was acquired by Ispat-Karmet JSC, Coal Division (now ArcelorMittal Temirtau JSC, Coal Division). The nearest community is Shakhtinsk town that is located 10 km to the southeast and Shakhan town that is located 7 km to the north. Saran city is located 18 km to the east. The regional centre, Karaganda City, is located about 35 km to the east.

The Tentekskaya mine was put in operation in 1979. In 1996 the mine was acquired by Ispat-Karmet JSC, Coal Division (now ArcelorMittal Temirtau JSC, Coal Division). The nearest community is Shakhtinsk town that is located 7 km to the southeast of the site and regional centre, Karaganda City, is located about 50 km away to the northeast. The railway station MPS-Karabas is located about 35 km to the southeast.

C.2 Description of Karaganda Basin and Relationship of AM Mines

Mine Relationship to Region

The mines of ArcelorMittal Temirtau, Coal Division are located in Karaganda Coal Basin.
Due to structural peculiarities the coal basin is divided into three geology-based mining areas: Karagandinskiy, Sherubay-Nurinskiy and Tentekskiy. The AM Coal Division Main Office is located in the regional centre - Karaganda city.

The Kostenko mine occupies the central part of the mining district of the Karaganda area. In the west and north-west it borders on Gorbacheva and Severnaya mines. In north-east and east it borders on Maykudukskaya and Karagandinskaya mines. All the mines with exception of Kostenko were closed down. In south and south-east the border goes through faults 2 and 67 forming the borders of Satakhanovskaya mine. In terms of location Kostenko mine field is within boundaries of Karaganda.

The Saranskaya and Kuzembaeva mines operate in Saran district of Karaganda area. In accordance with the geological mining area division it is identified in north-west and partially south-west wings of Karaganda sinclinal. In terms of administerial arrangement, the mines relate to Saran town of Karaganda region.

The Abayskaya and Shakhtinskaya mines operate in the territory of Sherubay-Nurinskiy, located in the south part of the north-east wing of Sherubay-Nurinskiy synclinal (brachysyncline). In terms of the administerial arrangement, the mines relate to the Bukhar-Zhyrau city district of Karaganda region.

The Lenina, Kazakhstanskaya and Tentekskaya mines operate in the territory of Tentekskiy, in the Tentekskaya mould. Tentekskaya mould is located in the north-west part of Sherubay-Nurinskiy synclinal. In the western part it is limited with the Tentekskiy fault, in the eastern part it is limited with the Sherubay-Nurinskiy upcast fault. The mould is of asymmetrical form and slightly outstretched in the south-west direction. It is 15km long and 10km wide. In terms of the administerial arrangement, the mines relate to the Bukhar-Zhyrau city district of Karaganda region.

Topography

Kostenko mine:
The surface of the mining district of the Karaganda area where the Kostenko mine is located is relatively flat. The surface is in 560-550m above sea level with exception of subsidence funnels formed due to mining operations.

Saranskaya and Kuzembaeva mines:
The surface of the mining district of Karaganda where Saranskaya and Kuzembaeva mines are located is slightly undulated. The surface is in 560-485m above sea level. The extreme south-east part the district is bisected by the Bolshaya Bukpa River. Its runoff within the district is regulated by an impounding reservoir used for farm irrigation. The Sokur River flows through the extreme north-west region.

Abayskaya and Shakhtinskaya mines:
The surface of mining district of Sherubay-Nurinskiy where the Abayskaya and Shakhtinskaya mines are locate is flat. The surface is in 469.3-481.4m above sea level. There are no reservoirs within the district.

The Sherubay-Nura River flows through the north-west part of the district. The river flows only for short period of the spring snow melt.

Lenina, Kazakhstanskaya and Tentekskaya mines:
The surface of the mining district of Tentekskiy where Lenina, Kazakhstanskaya and Tentekskaya mines are located is slightly undulating. The northern and eastern surfaces are 468-471m above sea level; the western and south-western surfaces are 475-785m above sea level.

There are no natural reservoirs within the district. The Tentek River that previously flowed from south to north in the eastern outskirt of the Tentekskaya mould, is now dammed in the area of Sasyk-Kol River. The Tentek River flows only during a short period of spring snow melt.

Climate

The climate is extremely continental. There is a stable snow cover in the winter months. The summer tends to be relatively dry, with a low amount of precipitation. The highest volume of precipitation occurs in spring and autumn. Average annual air temperature is +2.4 ^{0}C. The lowest temperatures are in January (-14.5 ^{0}C) and the highest are in July (+20.3 ^{0}C). In certain years, winter temperatures attained -40. ^{0}C and lower, summer temperature can reach +40. ^{0}C and above. The average annual precipitation is 304mm. Frequent and strong winds are typical for the area, with southwest winds predominating in the winter and northeast predominating in the summer.

The average annual wind velocity averages 5.1 m/sec and maximum velocity is 24 m/sec. Summer season duration is 3 months, the winter season - 5 months, autumn-spring - 4 months.
The local climate does not restrict the mine from operating throughout the year.

History

Milestones in the development of the mines in Karaganda Coal Basin are as follows:

1931-1936 – 16 small-scale operational exploring mines were constructed but all have been closed since then. These mines were built on outcropping areas.

1937-1941 – Construction of big-scale mines with more modern equipment and surface facilities began after detailied exploration of Karaganda Region.

1941-1945 – A lot of small-scale mines were constructed mainly on outcropping areas during Second World War for coal output expansion. In subsequent years these mines were closed or merged into bigger mines.

1946-1979 – Mining activity expanded. The exploration of Saranskiy, Sherubay-Nurinskiy and Tentekskiy coal-bearing areas began during this period. All of the mines within ArcelorMittal Temirtau JSC, Coal Division were put into operation during this period.

1979-1991 – The mining operations of the Karaganda basin consisted of 26 mines. During better years these mines produced up to 44.9 million tonnes(Mt) of coal (1977).

1991-1996 – Period of decline in production. During this period the level of production decreased from 36.0 Mt (1991) to 9.3 Mt (1999). Low producing and unpromising mines were abandoned during this period.

1996-2010 – 15 coal mines were transferred to ownership of Ispat-Karmet JSC (currently ArcelorMitall Temirtau JSC). There were several reorganizations, integrations, liquidations and stabilizations at mines during this period. As a result there are 8 existing mines of ArcelorMittal Temirtau JSC, Coal Division at the present time.

C.3 Geology and Resource Description

Geology

Area of the Karaganda coal basin contains more than 3000 km2 (Figure C-1) and it is formed by strata of Upper Devonian and Carbonic ages, Mesozoic and Cainozoic formations. Their thickness is about 4500 m, including approximately 4000 m of coal-bearing formations (Shakhanskaya, Tentekskaya, Dolinskaya, Nadkaragandinskaya, Karagandinskaya, Ashlyarikskaya and Akkudukskaya suits).

The Dubovskaya and Mikhailovskaya suits contain brown coal seams.

The Basin is divided into three large synclinals (from the West to the East): Sherubay-Nurinskaya, Karagandinskaya and Verkhnesokurskaya.

Verkhnesokurskaya synclinal is poorly explored because it is covered with mesozoic formations having thickness of 900-1000 m.

Productive formations are represented by the Ashlyarikskaya suit and bottom part of Karagandinskaya suit section.

Karagandinskaya synclinal occupies the central part of the coal basin.

The productive formations are represented by Ashlyarikskaya, Karagandinskaya and Dolinskaya suits.

The Sherubay-Nurinskaya synclinal is a highly complex fold. Productive formations are represented by Ashlyarikskaya, Karagandinskaya, Dolinskaya and Tentekskaya suits. Discontinuous faults are in all structures of the coal basin, but the most faulted formation is the South portion of the coal basin.

Coal formations are defined by four commercial coal-bearing suits: Ashlyarikskaya, Karagandinskaya, Dolinskaya and Tentekskaya. Their total thickness is about 2400m. Their section has up to 65 working seams with total thickness of 80-100 m.

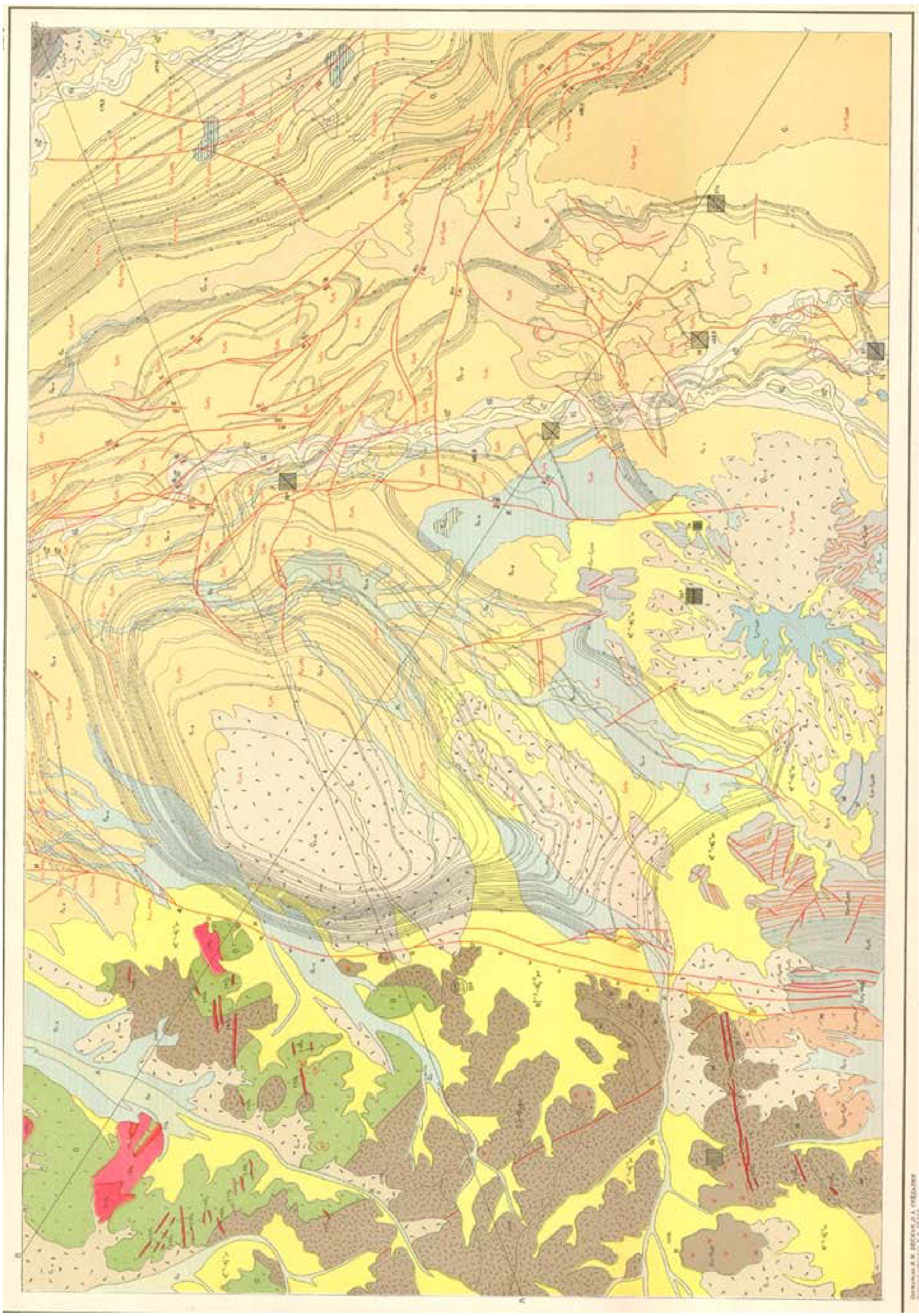
Thin and medium-thickness seams prevail in all coal-bering suits and only separate seams have a thickness of more than 5m in limited areas.

Seam structures are usually of complex type. Some seams are discontinuous both in structure and in thickness. All coals have good structure. The best quality coal is observed in coal seams of Dolinskaya suit and in top part of Karaganda suit section.

Zh, KZh, K and OS coal grades prevail according to grade composition. Metamorphism intensity increases from overlying seams to underlying seams, as well as within the area of coal basin from the north-east to the south-west.

At present the coal seams of the Ashlyarikskaya suit are not developed as they are highly ashy and difficult to wash.

Figure C-1. Geological plan of the Karaganda coal basin



Coal quality

Coking bituminous coals are spread within the boundaries of operating mines. There are some discontinuous beds of brown coals.

Central Karaganda area (Kostenko mine):

Material composition of coals – coal seams: K1, K2, K4, K13, K14 of Karagandinskaya suit are essentially composed of dull and semi-dull coals. Semi-bright coals are present in K5 seam. This type of coal typifies the K6 and K18 seams. The bright coal type is present only in K10 seam.

The average portion of mineral impurities in ROM is 12-26.5%. Their portion in clean coal is down to 8-10% except for K2 and K3 seams which contain 12-13% impurities.

Coal metamorphism – Metamorphism intensity increases along stratigraphic depth as well as in strike and on-dip. Coal metamorphism is an outgrowth of regional metamorphism.

Coal metamorphism of Karagandinskaya suit (K18 – K5) corresponds to coking coal grade almost over the whole area. Coals of K2 and K3 seams also have coke-ability but fall into the category of low-coking lean coals.

Saranskiy area (Saranskaya and Kuzembaeva mines):

Material composition of coals – coal seams: K1, K2, K4, K8-7, K13, K14 of Karagandinskaya suit are essentially composed of dull and semi-dull coals. Semi-bright coals are present in K5 seam. This type of coal typifies the K6 and K18 seams. The bright coal type is present only in K10 seam.

The average portion of mineral impurities in ROM is 12-26.5%. Their portion in clean coal is down to 8-10% except for K2 and K3 seams which contain 12-13% of impurities.

Coal metamorphism - Metamorphism intensity increases along stratigraphic depth as well as in strike and on-dip. Coal metamorphism is an outgrowth of regional metamorphism.

Coal metamorphism of Karagandinskaya suit (K18 – K5) corresponds to coking coal grade almost over the whole area. Coals of K2 and K3 seams also have coke-ability but fall into the category of low-coking lean coals.

Abayskaya mine field:

Material composition of coals – coal seams: K1, K2, K4, K8-7, K13, K14 of Karagandinskaya suit are essentially composed of dull and semi-dull coals. Semi-bright coals are present in K5 seam. This type of coal typifies the K6 and K18 seams. The bright coal type is present only in K10 seam.

The average portion of mineral impurities in ROM is 12-26.5%. Their portion in clean coal is down to 8-10% except for K2 and K3 seams which contain 12-13% of impurities.

AM Coal Resources

Table C-1 presents the mineral reserves of the AM mines in the Karaganda Basin as of 2011. Additional balanced coal reserves are presented in Table C-2. The historical coal production of the AM mines is presented in Table C-3 for 1965 through 2010.

Table C-1. Mineral Reserves Estimate as of 01.01.2011

		Kostenko		Kuzembaeva		Saranskaya		Abayskaya		Shakhtinskaya		Tentekskaya		Kazakhstanskaya		Lenina		TOTAL	
		K Tonnes	**A, %**	**K Tonnes**	**A, %**	**K Tonnes**	**A, %**	**K Tonnes**	**A, %**	**K Tonnes**	**A, %**	**K Tonnes**	**A, %**	**K Tonnes**	**A, %**	**K Tonnes**	**A, %**	**K Tonnes**	**A, %**
Reserves	**Proven**	**3425**	24.7	**2585**	24.1	**1915**	23.2	**1331**	25.7	**410**	18.5	**720**	21.3	**1823**	23.9	**1102**	20.0	**13311**	22.7
	Probable	**32722**	24.7	**24707**	24.1	**25235**	23.2	**17619**	25.7	**17500**	18.5	**18170**	21.3	**23537**	23.9	**20188**	20.0	**179678**	22.7
	Proven + Probable	**36147**	24.7	**27292**	24.1	**27150**	23.2	**18950**	25.7	**17910**	18.5	**18890**	21.3	**25360**	23.9	**21290**	20.0	**192989**	22.7
Resources	**Measured**	**37452**	24.9	**23499**	24.5	**55767**	24.1	**27642**	25.7	**12318**	18.5	**46928**	22.0	**39264**	20.0	**23501**	19.3	**266371**	22.4
	Indicated	**40082**	24.9	**35046**	24.5	**32029**	24.1	**35868**	25.7	**18118**	18.5	**69920**	22.0	**39321**	20.0	**21748**	19.3	**292132**	22.4
	Measured + Indicated	**107534**	24.9	**58545**	24.5	**87796**	24.1	**63510**	25.7	**30436**	18.5	**116848**	22.0	**78585**	20.0	**45249**	19.3	**588503**	22.4
	Inferred	**0**	0.0	**0**	0.0	**0**	0.0	**0**	0.0	**0**	0.0	**6530**	0.0	**0**	0.0	**1383**	27.5	**7913**	27.5

Table C-2. Additional Balanced Reserves

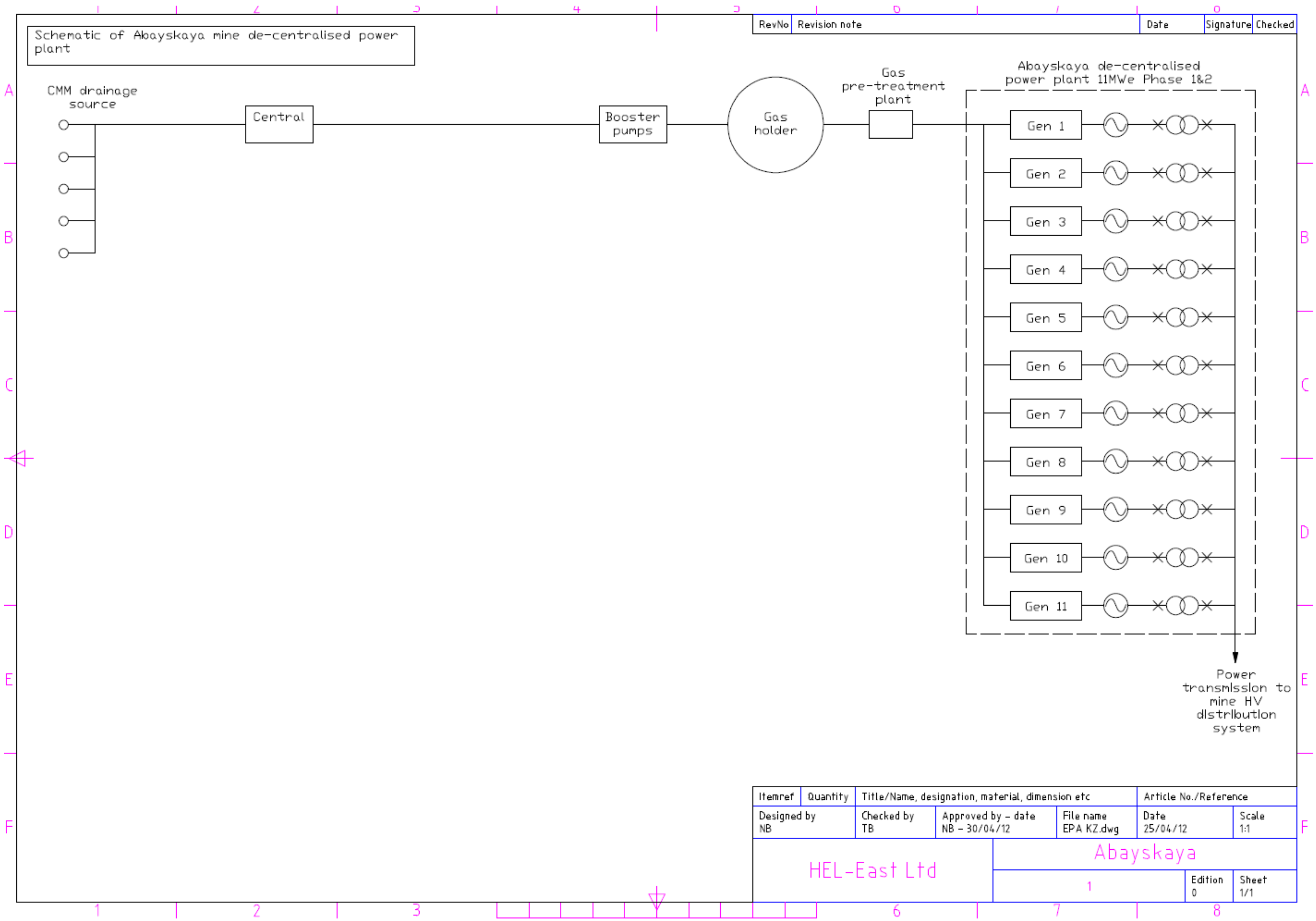
Deposit type	Property	Reserves				
		Categories				
		A	**B**	**C1**	**C2**	**A+B+C1+C2**
Stratified, Bituminous coal	Kostenko Mine	24387	70176	179079	0	273637
	Kuzembaeva Mine	24315	58489	122368	0	205172
	Saranskaya Mine	80005	95360	100780	0	276145
	Abayskaya Mine	7819	78037	148450	0	234306
	Shakhtinskaya Mine	3562	33652	54697	0	91911
	Kazakhstanskaya Mine	8845	65989	75878	0	150712

Table C-3. History of coal output at mines of coal division

Mines	Annual coal output, Mt												
	1965	1970	1975	1980	1985	1995	2001	2005	2006	2007	2008	2009	2010
Kostenko	1.969	2.481	3.104	3.820	3.777	1.847	1.681	2.005	1.586	1.886	2.560	2.472	2.278
Kuzembaeva	1.338	1.641	2.160	1.830	1.690	0.803	1.220	1.285	1.866	1.193	1.557	1.715	1.638
Saranskaya	0.881	0.909	0.820	0.869	1.262	0.473	1.507	1.506	1.289	1.500	1.110	1.416	1.289
Abayskaya	0.668	0.762	1.033	1.168	1.351	0.615	0.812	1.213	1.280	1.291	0.771	1.204	1.164
Kazakhstanskaya	-	1.082	2.486	2.239	1.945	0.565	1.262	0.971	1.447	1.845	1.284	0.951	1.434
Lenina	1.735	2.553	2.897	2.378	2.427	1.572	1.275	1.531	1.600	1.818	1.493	1.450	1.258
Shakhtinskaya	0.547	-	1.238	1.540	1.666	0.618	1.038	1.398	1.563	1.169	1.396	0.960	0.900
Tentekskaya	-	-	-	1.665	2.544	1.052	0.899	1.254	0.910	1.497	0.856	0.932	0.910
TOTAL	**7.138**	**9.428**	**13.738**	**15.509**	**16.662**	**7.545**	**9.694**	**11.163**	**11.541**	**12.199**	**11.027**	**11.100**	**10.871**

Appendix D

Methane drainage and utilization block diagrams for each site



Schematic of Abayskaya mine de-centralised power plant
RevNo
Revision note
Date
Signature
Checked
CMM drainage source
Central
Booster pumps
Gas holder
Gas pre-treatment plant
Abayskaya de-centralised power plant 11MWe Phase 1&2
Gen 1
Gen 2
Gen 3
Gen 4
Gen 5
Gen 6
Gen 7
Gen 8
Gen 9
Gen 10
Gen 11
Power transmission to mine HV distribution system
Itemref
Quantity
Title/Name, designation, material, dimension etc
Article No./Reference
Designed by NB
Checked by TB
Approved by – date NB – 30/04/12
File name EPA KZ.dwg
Date 25/04/12
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Abayskaya
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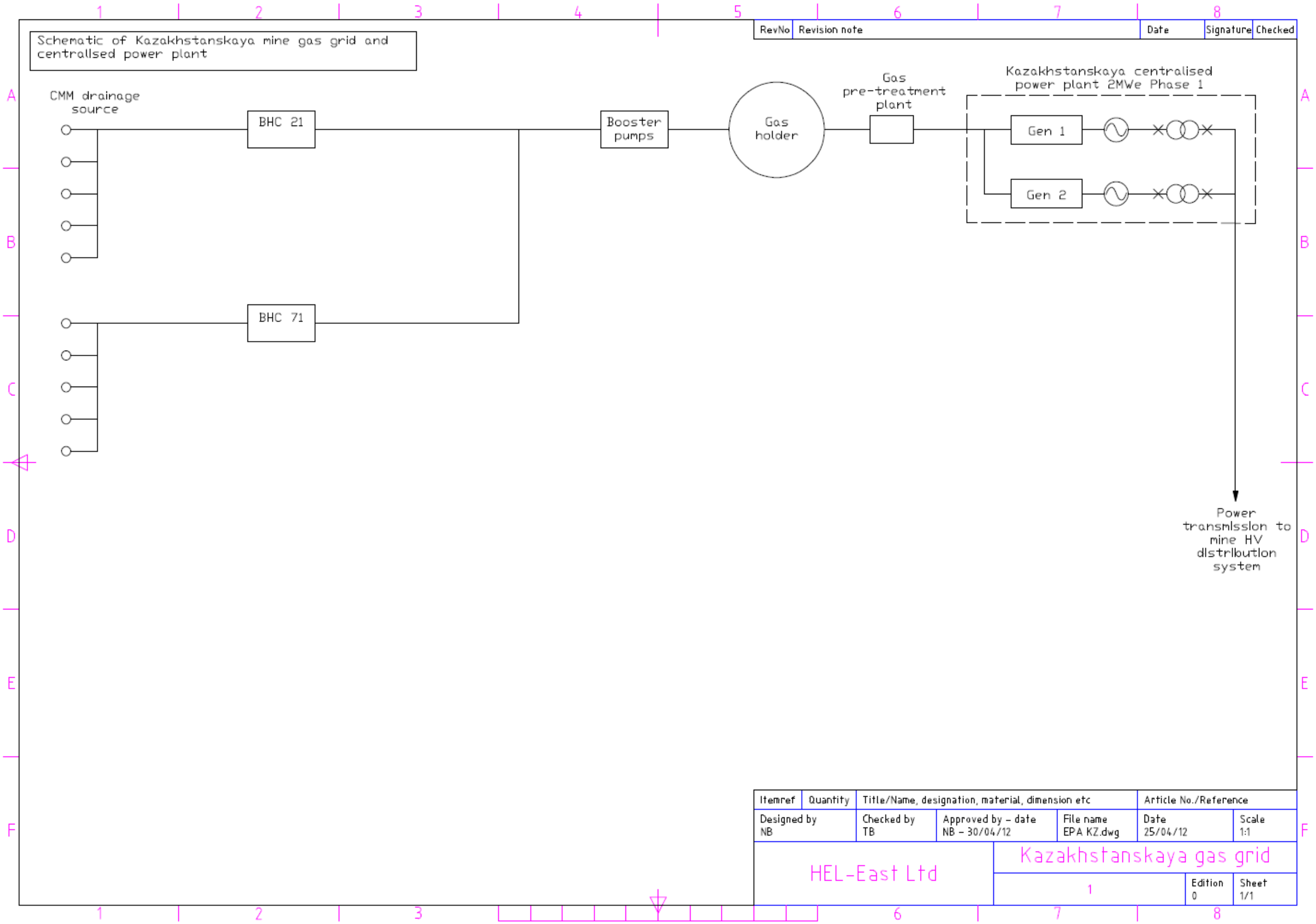
Sheet 1/1


Schematic of Kazakhstanskaya mine gas grid and centralised power plant
RevNo
Revision note
Date
Signature
Checked
CMM drainage source
BHC 21
BHC 71
Booster pumps
Gas holder
Gas pre-treatment plant
Kazakhstanskaya centralised power plant 2MWe Phase 1
Gen 1
Gen 2
Power transmission to mine HV distribution system
Itemref
Quantity
Title/Name, designation, material, dimension etc
Article No./Reference
Designed by NB
Checked by TB
Approved by – date NB – 30/04/12
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Date 25/04/12
Scale 1:1
HEL-East Ltd
Kazakhstanskaya gas grid
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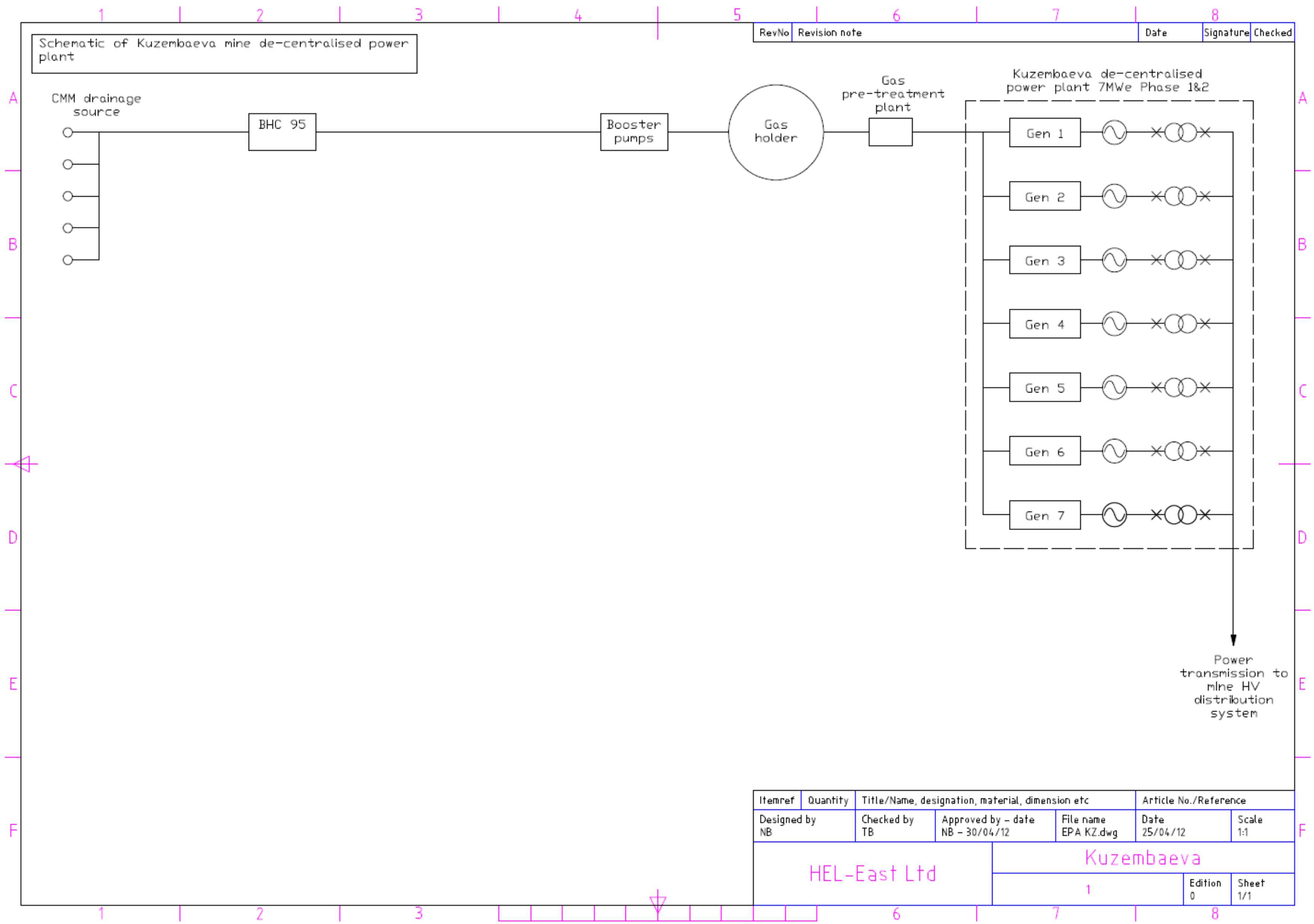
Edition 0
Sheet 1/1


Schematic of Kuzembaeva mine de-centralised power plant
RevNo
Revision note
Date
Signature
Checked
CMM drainage source
BHC 95
Booster pumps
Gas holder
Gas pre-treatment plant
Kuzembaeva de-centralised power plant 7MWe Phase 1&2
Gen 1
Gen 2
Gen 3
Gen 4
Gen 5
Gen 6
Gen 7
Power transmission to mine HV distribution system
Itemref
Quantity
Title/Name, designation, material, dimension etc
Article No./Reference
Designed by NB
Checked by TB
Approved by – date NB – 30/04/12
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Kuzembaeva
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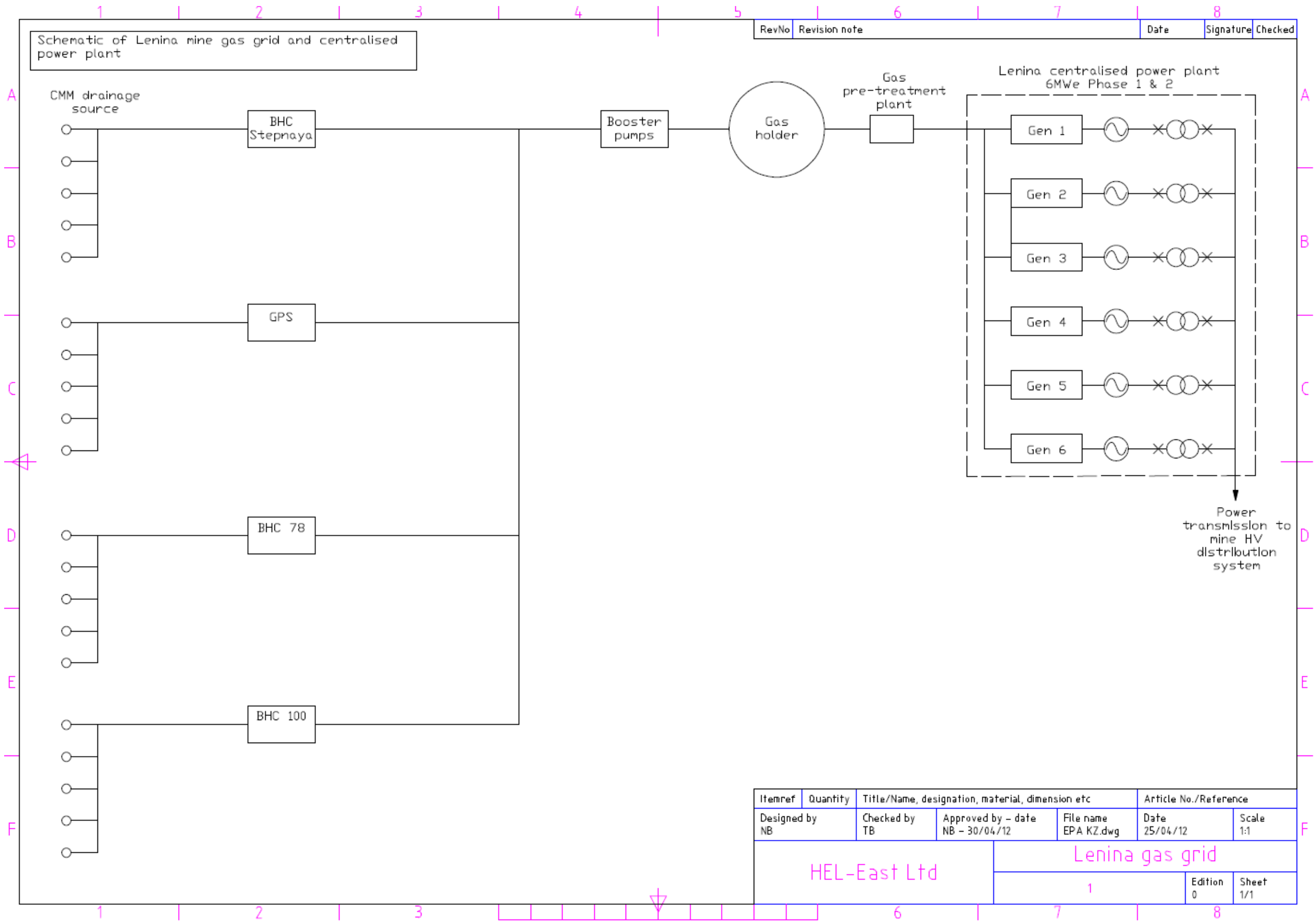
Schematic of Lenina mine gas grid and centralised power plant
CMM drainage source
BHC Stepnaya
GPS
BHC 78
BHC 100
Booster pumps
Gas holder
Gas pre-treatment plant
Lenina centralised power plant 6MWe Phase 1 & 2
Gen 1
Gen 2
Gen 3
Gen 4
Gen 5
Gen 6
Power transmission to mine HV distribution system
RevNo
Revision note
Date
Signature
Checked
Itemref
Quantity
Title/Name, designation, material, dimension etc
Article No./Reference
Designed by NB
Checked by TB
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Date 25/04/12
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HEL-East Ltd
Lenina gas grid
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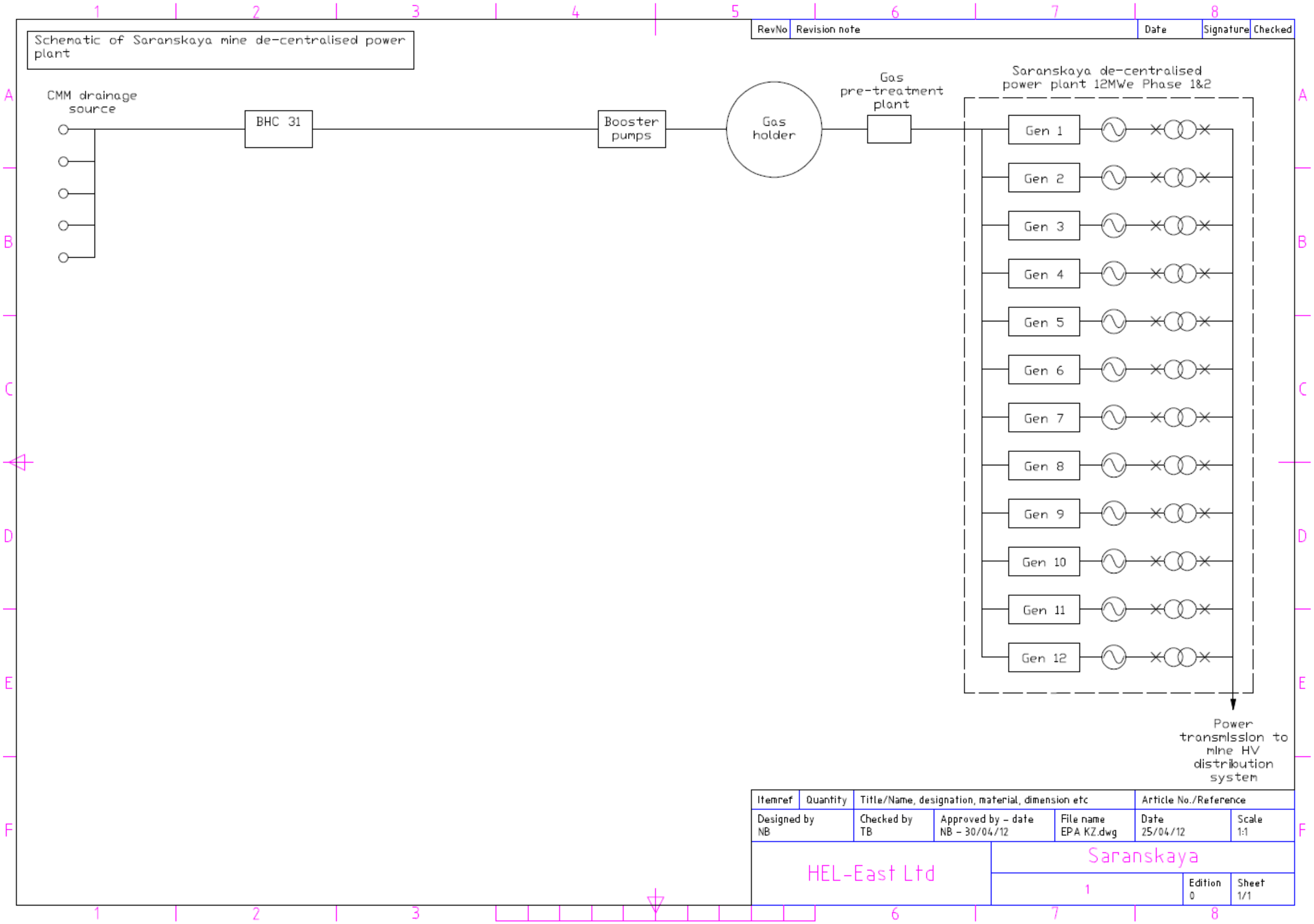
Edition 0
Sheet 1/1


Schematic of Saranskaya mine de-centralised power plant
RevNo
Revision note
Date
Signature
Checked
CMM drainage source
BHC 31
Booster pumps
Gas holder
Gas pre-treatment plant
Saranskaya de-centralised power plant 12MWe Phase 1&2
Gen 1
Gen 2
Gen 3
Gen 4
Gen 5
Gen 6
Gen 7
Gen 8
Gen 9
Gen 10
Gen 11
Gen 12
Power transmission to mine HV distribution system
Itemref
Quantity
Title/Name, designation, material, dimension etc
Article No./Reference
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Date 25/04/12
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Saranskaya
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Edition 0
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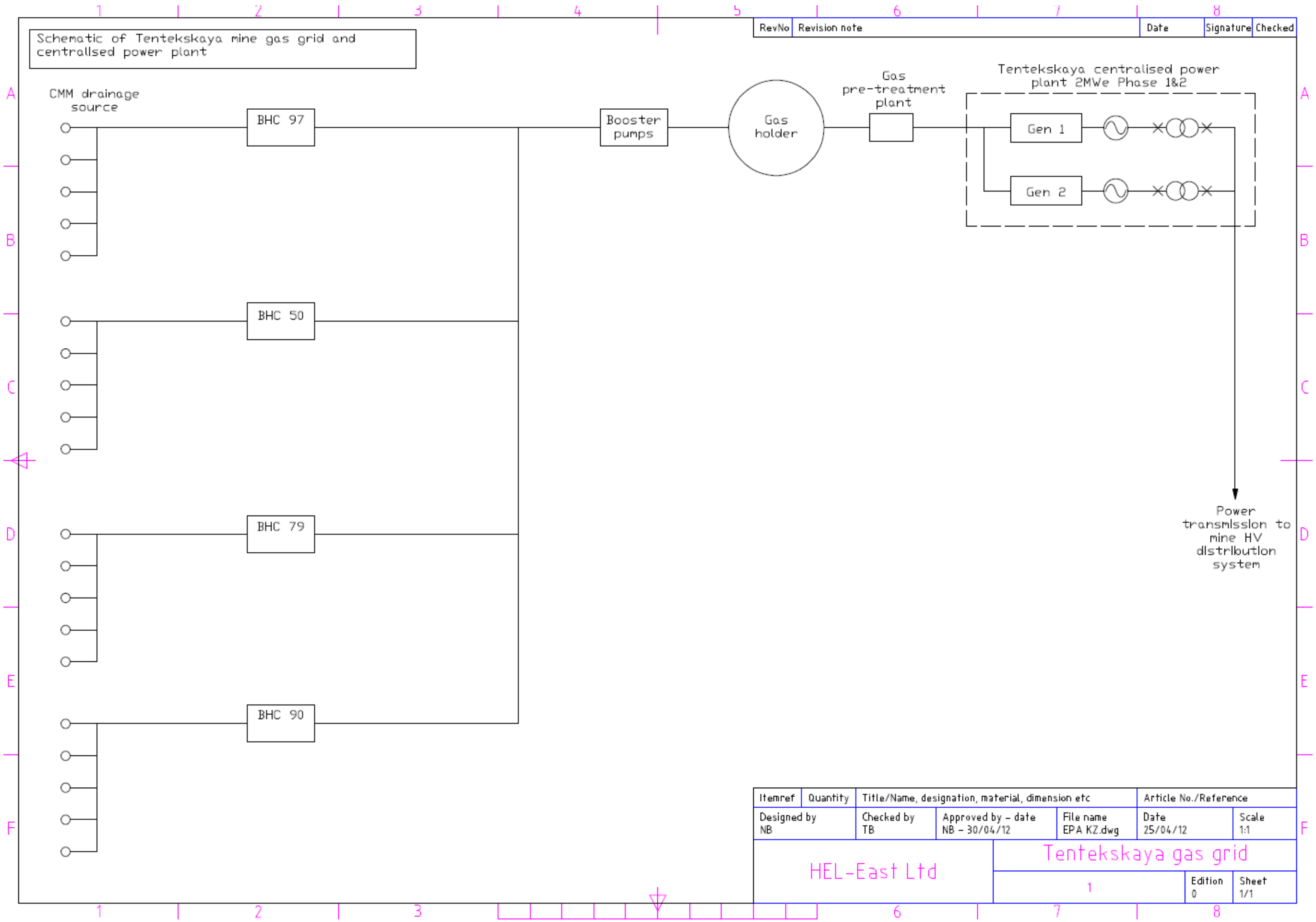
Schematic of Tentekskaya mine gas grid and centralised power plant
CMM drainage source
BHC 97
BHC 50
BHC 79
BHC 90
Booster pumps
Gas holder
Gas pre-treatment plant
Tentekskaya centralised power plant 2MWe Phase 1&2
Gen 1
Gen 2
Power transmission to mine HV distribution system
RevNo
Revision note
Date
Signature
Checked
Itemref
Quantity
Title/Name, designation, material, dimension etc
Article No./Reference
Designed by NB
Checked by TB
Approved by – date NB – 30/04/12
File name EPA KZ.dwg
Date 25/04/12
Scale 1:1
HEL-East Ltd
Tentekskaya gas grid
1
Edition 0
Sheet 1/1