Development of Two Case Studies on Mine Methane Capture and Utilisation in China

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Shi Su, Ting Ren, Rao Balusu, Andrew Beath, Hua Guo, Cliff Mallett

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CSIRO Exploration and Mining

PO Box 883, Kenmore, QLD 4069, Australia

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EXECUTIVE SUMMARY

The Methane to Markets Partnership is an international initiative that advances cost-effective, near-term methane recovery and use as a clean energy source in Partner Countries. The two case studies of this project aim at investigating the options for capturing and utilising methane from underground coal mines in China by implementing Australian innovative technologies, so that potential M2M projects could be developed to effectively capture and efficiently utilise coal mine methane.

China is the biggest coal producer in the world with annual coal output of 1.95 billion tonnes in 2004. China is also the world's largest coal consumer, with coal accounting for approximately 70% of China's total energy consumption. Currently, China is responsible for about 45% of the total global ventilation air methane emissions. Although gas drainage efficiency in China has been increased from 15% in 1998 to 26% in 2004, much of the captured gas is poor in quality. It is estimated that over 70-80% of the drainage gas has a methane concentration of less than 30%.

The principal objective of Case Study A is to provide an overview of gas drainage practices in a representative Chinese coal mine and those in Australian coal mines, and investigate how to effectively improve the recovery and utilisation of drainage gas in a Chinese coal mine by using some of the Australian technologies. The coal mine P1, located in Huainan mining area in Anhui Province of China, has been identified for this study. P1 is a gassy mine and as such a range of drainage methods have been practised, and more recently, part of the captured gas is being used for power generation. A review of the current drainage practices indicates that there is great potential for improving gas drainage efficiency and gas purity which are a bottleneck for power generation purposes in Huainan mining area. An integrated approach has been developed by CSIRO and demonstrated successfully in Australian coal mines for improved goaf gas drainage and management. The application of advanced Australian technologies and know-how, including those developed by CSIRO, will help the improvement of gas drainage and hence the development of gas utilisation projects in P1 mine and other areas of China. On the basis of field observations and analysis of available data, Case Study A also proposed a preliminary work plan for improving gas recovery at P1 mine, as well as an initial evaluation of project economics.

The Case Study B aims at investigating how to effectively capture and utilise ventilation air methane from a Chinese coalmine. For this case, existing and developing ventilation air methane (VAM) mitigation and utilisation technologies have been reviewed, and then the assessment of implementation of these technologies into a Chinese coal mine was carried out by conducting the system configuration and conceptual plant designs and determination of plant potential and operating status. In addition, an evaluation of preliminary economic benefit based on the mine methane emissions from this coal mine has been performed, so that best options were identified for the mine. The Case Study B indicated that no technology has been successfully demonstrated at a mine site for the utilisation of VAM. No single technology solution could be applied to the treatment of methane in mine ventilation air. As circumstances at mines are dependent on local conditions, a range of technology options would have to be combined to provide the optimum result for any particular site. Thermal flow reverse reactor (TFRR), catalytic flow reverse reactor (CFRR) and catalytic monolithic reactor (CMR) would be technically feasible for the VAM mitigation depending minimum CH_4 concentration of the ventilation air, but would not be economically beneficial without some form of carbon credit. The 1% CH_4 lean burn turbine would be the best option proposed so far for the utilisation of VAM. The combined lean burn turbine and gas engine system promises to maximally use both drainage gas and VAM with highest efficiency and output for many mines. Care should be taken for ventilation air cleaning. In addition, for Case Study B, the scenario would be different if the drainage gas quality could be improved to a CH_4 concentration of $\geq$25%. In other words, the combined lean burn turbine and gas engine power plant system would be chosen to achieve the maximum utilisation of drainage gas and VAM with highest efficiency and output.

1 INTRODUCTION

1.1 BACKGROUND

Australia, the United States, Japan and China co-hosted Methane to Markets regional workshop in China on 2 December 2005. The workshop aims focussed on coal mine methane project opportunities in China, including prospective areas, technologies, legal issues and markets. The AGO engaged the services of CSIRO to prepare, present and report on two case studies. The case studies focus on enhancing coal mine methane capture and utilisation in Chinese coalmines through improved gas drainage systems and /or ventilation air, and promote new Australian technologies and expertise.

The two case studies illustrate the procedures for and the economics of implementing coal mine methane (CMM) and ventilation air methane (VAM) projects in China, highlight Australian expertise in these areas, and facilitate commercial opportunities for Australian businesses. The case studies were developed in collaboration with relevant Chinese agencies and companies based on data obtained from two operational mines in China.

The case studies results were presented by the CSIRO at the Beijing Methane to Markets Workshop, with the aim of demonstrating to workshop participants the opportunities for CMM and VAM projects in China under the Methane to Markets Partnership (M2M) and to facilitate the establishment of coal mine methane capture and utilisation projects in China through M2M.

1.2 COAL MINE METHANE EMISSIONS IN CHINA

China is the biggest coal producer in the world with annual coal output of 1.95 billion tonnes in 2004. China is also the world's largest coal consumer, with coal accounting for approximately 70% of China's total energy consumption. The geological structure of Chinese coal mines is very complicated; huge amounts of methane often burst from coal seams, and many coal mines are very gassy. To date, the reserve of CMM in China is not accurately quantified, but the volume of explored resource appears to be around 35 trillion m^3, which is equal to the natural gas reserve in China. Recent statistics suggest that Chinese coal mines emit up to 13 billion m^3 of methane into the atmosphere annually. Ventilation air methane accounts for approximately 95% of the methane emitted. Hence, China is responsible for about 45% of the total global ventilation air methane emissions. Although gas drainage efficiency in China has been increased from 15% in 1998 to 26% in 2004, much of the captured gas is poor in quality. It is estimated that over 70-80% of the drainage gas has a methane concentration of less than 30%. Table 1 shows a snapshot of typical gas emissions from a Chinese coal mine on 10 October 2005, which shows the poor quality of the drainage gas.

Table 1 Methane emissions from a Chinese coal mine

Date	Ventilation air		Drainage gas												VAM, %
	CH_4, %	CH_4, m^3/min	Surface goaf		roof		Return fringe		Gas gate		In-seam		others		
			CH_4,%	CH_4, m^3/min	CH_4, %	CH_4, m^3/min	CH_4, %	CH_4, m^3/min	CH_4, %	CH_4, m^3/min	CH_4, %	CH_4, m^3/min	CH_4, %	CH_4, m^3/min	
10/10/05	0.22	57	50-80	9	8	2.5	6	1.5	26	27	10	2	12	13.6	50.8

The Chinese Government is currently implementing a strategy to control mine gas outbursts and improve mine safety through the efficient utilisation of mine methane, i.e. both using coal mine methane and draining the methane for safety. Accordingly, there is a need for technologies to manage coal mine methane through the improvement of gas drainage systems and utilisation of both drainage captured gas and diluted methane in ventilation air. This presents an opportunity to apply innovative, cost-effective methane capture and utilisation technologies in these coal mines, not only to tackle greenhouse gas emissions and recover waste energy, but also to improve coal mine safety.

World wide methane emissions in 2000 from mine ventilation air alone were over 237MMT CO_2-equivalent [1]. Moreover, underground coal mining is by far the most important source of fugitive mine methane, and approximately 70% of all coal mining related emissions are from underground ventilation air [2]. Ventilation air methane capture and utilisation is a major problem because (1) it represents the largest proportion of methane emissions from coal mines in China; and (2) the air volume flow rate is large and the methane resource is dilute and variable in concentration. VAM mitigation/utilisation requires either treatment in its dilute state, or concentration up to levels that can be used in conventional methane fuelled engines. Effective technology for increasing the concentration of methane is not available but is being researched. Most work has focussed on the oxidation of very low concentration methane. These processes may be classified as either thermal oxidation or catalytic oxidation, based on the combustion kinetic mechanism.

1.3 SCOPE OF CASE STUDY A

The study scope of Case Study A involves the investigation of the following aspects associated with coal mine gas drainage:

- Characteristic data of a typical Chinese mine site geological information, mine layout, mining plan etc.;
- Overview of mine methane enhanced recovery tools for both pre- and post-drainage gas systems;
- Project work program for development of optimum gas drainage techniques for a mine site in China;
- Results on the potential of efficient drainage gas power plants, and their preliminary economics (this will demonstrate how to efficiently utilise the drainage gas).

1.4 SCOPE OF CASE STUDY B

The study scope of Case Study B includes the following investigations:

- Characteristic data of methane emissions at the Case Study mine;
- Overview of existing and developing VAM mitigation and utilisation technologies;
- Identify technology options for the mine site application;
- System configuration and conceptual plant designs for determined feasible technologies, and investigation results on high efficiency system combinations;
- Results for plant capacity, operating status and parameters;
- Preliminary economic results.

2 CASE STUDY A

IMPROVEMENT OF DRAINAGE GAS AND ITS UTILISATION FROM A TYPICAL CHINESE COAL MINE

2.1 INTRODUCTION

The specific objective of Case Study A is to identify a representative Chinese coalmine, review its current methane drainage operations and investigate how to effectively improve coal mine methane recovery and utilise the drainage gas, by using some of the advanced technologies developed in Australia.

For this purpose, a Chinese coal mine P1 located in Huainan Mining Area of Anhui province, China, has been identified and an overview of methane drainage operations undertaken to identify potential areas for gas drainage improvements in view of the advanced gas drainage technologies in Australia.

This part of the report summarises the major work components for Case Study A.

2.2 REVIEW OF A REPRESENTATIVE COAL MINE IN CHINA

Initial review studies have been conducted to collate essential information from a typical coal mine in China. This coal mine, identified as P1 mine, is located in Huainan coal mining area, Anhui Province of China, as shown in Figure 1. The Huainan coalfield, about 3,260km^2 in area, spreads on the middle reaches of the Huaihe River, about 100 km from Hefei, the capital city of Anhui province, 300km from Nanjing and 500km from Shanghai. With large coal reserves, the Huainan Coal Mining Group (HCMG) has nine active mines, producing 29.8 million tonnes of coal in 2004. Gas drainage is practised in many of these coal mines, draining over 50 million m^3 of methane annually. This is creating opportunities for coal mine methane recovery and utilization projects. All the coal mines are classified as gassy and outburst-prone mines, with a mining depth up to 800m.

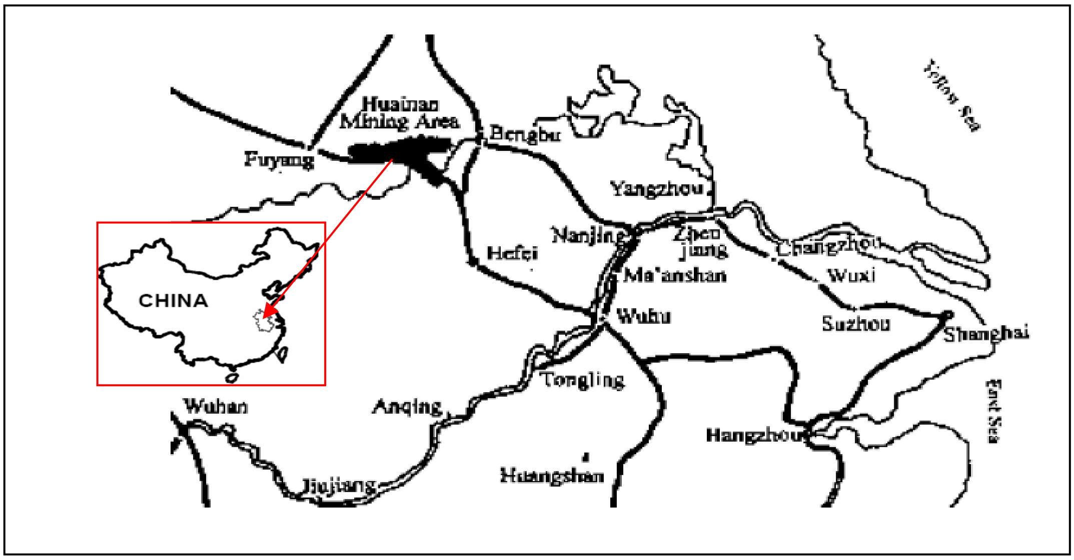


Figure 1 Location of the Huainan Mining Area

P1 mine started production in 1983 with a capacity of 4Mt annual output. P1 is a gassy mine, with a relative gas emission of 113m^3/min, absolute gas emission 23m^3/t, and as such a range of gas drainage techniques are used in this mine.

The following information/data was collected during field studies in this area:
- General information about the mine, including its location, area of mine take, production capacity, and production levels;
- Mine geology, including major geological structure, hydrogeology, faults;
- Stratigraphy, including seam sequences and characterisation, thickness, coal quality;
- Gas content – including measured and predicted gas contents for all the seams;
- Mine gas emission and predictions;
- Coal mine methane drainage – including drainage facilities, capacity and pipe lines, gas holders, drilling equipment, drainage methods and gas drainage data for selected panels;
- Gas utilisation – use of drainage gas for both domestic use and power generation;
- Mine ventilation - including main fans, mine ventilation systems and airflow rates to different panels/districts of the mine.

The above information/data was supported by mine plans, typical stratigraphy of the mine, and drainage borehole designs. In addition, a visit was made to the mine site on 5 December 2005, following the M2M workshop in Beijing.

It is important that every effort is made to collect detailed information/data from the mine sites as this pool of data/information forms the basis for any gas drainage and utilisation design in the mine.

2.3 OVERVIEW OF TOOLS AND TECHNOLOGIES FOR MINE GAS DRAINAGE

An overview study of available tools and technologies for coal mine methane drainage in P1 Mine and Australia has been conducted with the objective of understanding their applications and limitations under different mine conditions. The focus has been on techniques that are currently used in most gassy Chinese coal mines, such as those in P1 mine, and those in Australian underground coal mines that are applicable to the identified Chinese coal mine conditions. The overview study covered the following areas:

<u>Gas Drainage in P1 Mine, Huainan Mining Area, China</u>

- *Gas Emission Prediction Techniques* – Estimations of the expected gas emissions from the working area in a mine are needed for ventilation design and methane drainage requirements. Gas emission prediction techniques used in the mine include a combination of empirical, numerical, analytical or statistical techniques. Some of these methods/models are designed specifically to predict emissions in longwall sections, others to predict emissions in headings.

  The most commonly used approach for gas prediction is the <u>Specific Emission Method</u> – in which the specific emission value (termed relative emission in China) is derived from previous experience of a mine, a particular area of a mine or of neighbouring mines where similar mining methods are being used in similar geological conditions. District ventilation and gas drainage planning is often adequately served by this approach. For many practical mining purposes this simple method is considered satisfactory provided that factors which may lead to unusual emissions can be identified in advance. Implementation of the method is assisted by systematic measurement, recording and processing of mine environmental data.

  <u>Empirical methane prediction methods</u> are generally simple, requiring few input parameters and some are specific to a particular coalfield. The longwall gas emission prediction methods consider some or all of the following gas emission sources:
  - coal seams in a gas emission zone above and below the worked seam,
  - rock strata in the gas emission zone,

- the worked seam itself including the coalface and any unworked coal left in the roof and floor,
- coal on conveyors.

- *Mine Gas Drainage Methods* - A range of gas drainage methods have been developed and used in coal mines with varying geological and mining conditions in China. These include both pre- and post- drainage using surface and underground methods. Goaf drainage using surface goaf holes and pipes laid in the goaf areas are also being practised in some mines in China. Advanced underground inseam guided drilling techniques have been demonstrated by foreign contractors and are being applied with some success at a Sino-US joint venture coal mining operation in Shanxi Province.

  A study of the gas drainage methods practised in P1 Mine and other mines in Huainan Coal has been the focal of this overview as it is likely that these techniques will be used and integrated with any new techniques for improved gas recovery. A range of gas drainage methods are used in P1 mine, these include:

In seam pre-drainage, using
- Roof/floor boreholes
- In seam boreholes
- Development Drainage

Adjacent seam pre-drainage, using
- Cross-measure boreholes
- Surface borehole drainage

Goaf drainage, using
- Roof holes
- Gas drainage roadway in the roof strata (as shown in Figure 2)
- Goaf drainage pipes
- Tailgate drainage
- Surface goaf holes

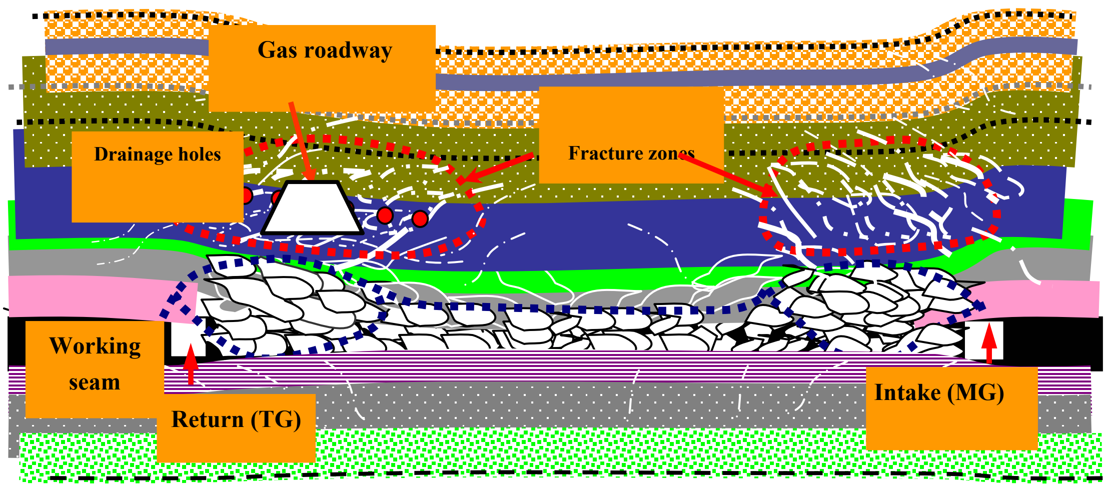


Figure 2 Schematic layout of roof drainage borehole /gas roadway in the roof – gas drainage method in P1 mine, Huainan area [3]

Figure 2 shows a schematic layout of gas drainage method using a gas roadway located in the roof strata on the tailgate side of the panel. This method basically involves the development of a roadway in the roof strata along the direction of face retreating direction, with the objective to intercept gas released from the goaf and adjacent gas reservoir in the roof. Some of the above gas drainage techniques are illustrated in Appendix A.

P1 mine has a total drainage capacity of 433m^3/min and presently recovering from the following three sources:

- Surface boreholes - 9m^3/min pure CH_4 (concentration 50-80%),
- Roof/floor holes and goaf drainage pipes – 15 m^3/min pure CH_4 (concentration 15%),
- Roof gas drainage roadway - 28 m^3/min pure CH_4 (concentration 23%).

It can be noted from the above drainage data that the average methane content of the captured gas is approximately 22%, which is well below the desired usable level of 30%, particularly for drainage gas coming from roof/floor holes and goaf drainage pipes.

During the field studies, it was identified that the low gas concentration of drainage gas (CH_4% by volume) and hence the low total pure gas flow rate (m^3/min) were largely attributed to the following factors:

- Borehole positioning and sealing – the improper sealing and borehole positioning (borehole length, spacing, standpipes, if any, and sealing procedures/materials) lead to high air leakage into the drainage systems. Excessive pump suction pressure and air leakages into the joints of the drainage pipelines are also contributing factors. It is necessary to ensure that the drainage network and the entire gas collecting ranges are as gas tight as practicable.

- Drainage techniques – there is a need to carry out a critical review and optimisation of the underground drainage practices, including roof/floor drainage and goaf pipes, so that the potential of these drainage holes/pipes can be maximised to obtain a constant and methane rich gas flow for utilisation. The use of surface goaf hole drainage techniques offers the potential for significantly improved gas flow rate and purity and as such it should be encouraged whenever the mining/geological conditions of longwall panels are suitable.

- On-line gas drainage monitoring and control – It is important to provide timely information on the purities of the drained gas, flow rates as well as suction pressures applied to different parts of the drainage network so that the gas drainage system can be managed and regulated most effectively. For this purpose, a real time on-line monitoring must be installed.

A number of advanced but practical approaches developed in Australia can be introduced to these mines in Huainan to improve gas drainage and subsequently, utilisation.

<u>Gas drainage in Australia</u>

- Gas Emission Prediction Techniques – Gas drainage and mine feasibility studies routinely incorporate mine gas reservoir assessment and simulations to define gas reservoir characteristics and longwall gas emission rates as well as gas drainage and utilisation potential. In addition to the statistical approach of European origin, i.e. the former British Coal model, a range of simulation tools are now available for gas emission prediction, these include CoalGas, SIMED II, ECLIPSE, FLAC, COMET and an in-house code COSFLOW developed by CSIRO.

- Mine gas drainage methods – Mine-wide gas drainage strategies are adopted as a response to outbursting and high gas emissions in Australian underground coal mines. Figure 3 shows a summary of the gas drainage techniques that are used in a typical Australian underground coal mine. In addition to some of these pre- and post gas drainage methods applied in Chinese coal mines, a range of innovative gas drainage methods have recently been developed and used in Australian mines. These include:

- Surface to seam directional drilling, in particular, the development of Medium Radius Drilling (MRD) technology for coal bed methane (CBM) and coal mine gas drainage, offers the potential to maximise gas recovery efficiency with minium interruption to mining operations. This technique has increasingly been used for pre-drainage in a number of Australian coal mines.

- Tight-radius drilling (TRD) to pre-drain methane from coal seams it intends to mine in the future. This technique involves the use of vertical wells drilled into the earth by conventional methods. A drilling apparatus, which has the ability to turn within an extremely tight (30cm) radius, can be lowered and raised to drill within multiple coal seams beneath the surface. In each coal seam it can drill outwards in any direction, producing as many lateral holes as required. The TRD method is not dependent on underground mining activities, and can therefore be deployed in a region prior to mine development.

- Surface goaf holes – this technique is now increasingly used by Australian coal mines to drain gas from the goafs behind longwalls.

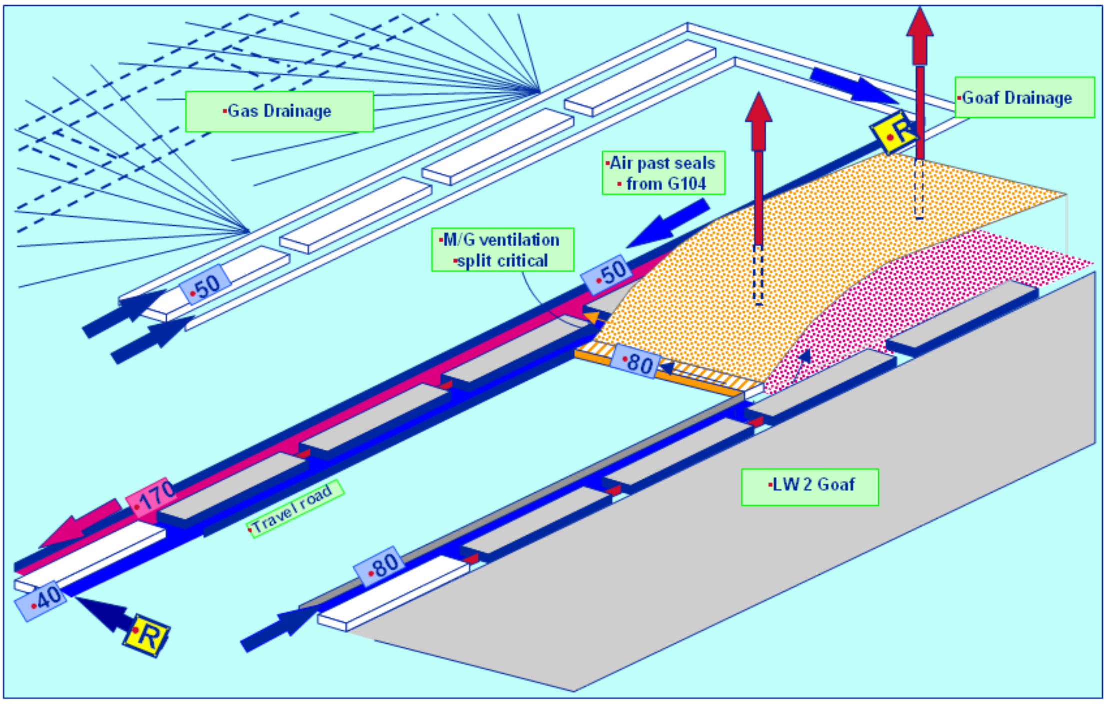


Figure 3 Gas drainage techniques used in a typical Australian underground coal mine

To address the complex goaf gas issues and subsequently develop effective gas management and drainage strategies, it is essential to obtain a fundamental understanding of the gas flow dynamics in longwall goafs under various conditions. An integrated approach has been developed by CSIRO to assist the development of optimum gas drainage strategies with improved gas recovery. This approach involves the application of several techniques, including:

- Tracer gas studies to enhance the understanding of the gas flow patterns;
- Computational Fluid Dynamics (CFD) models to study the goaf gas flow and effect of various parameters and control strategies;

- Fully coupled geo-mechanical and gas flow modelling to understand strata caving mechanisms and predict gas emissions;
- Field demonstrations of optimum goaf gas control strategies.

This approach has been applied to goaf gas drainage operations in several Australian coal mines and achieved excellent gas recovery results.

2.4 FIELD DEMONSTRATION STUDIES IN AUSTRALIA

Results of two field demonstration studies conducted in Australia using the above techniques to optimise goaf gas drainage operations were examined in this study.

Mine A

- Mine A, located in New South Wales, is one of the gassiest mines in Australia. The mine has a production capacity of 4 million tonnes per year and operates a single longwall face and 2 continuous miner sections. The coal seams of the working section, floor and immediate roof average a total of 20m in thickness. The depth of the workings ranges from 200 to 400m. The longwall faces are typically 200m wide with panel lengths in the range of 1,800 to 2,300m.

Gas control at this mine was very complicated due to the presence of the following conditions:

- Thick coal seam (>20m),
- Low in-situ permeability,
- Very high goaf gas emissions > 7,000 l/s,
- Proneness to spontaneous combustion.

The thick coal seam presented a huge gas reservoir close to the working section and resulted in very high goaf gas emissions, in the order of 7,000l/s to 9,000l/s, with specific gas emissions between $50m^3/t$ and $80m^3/t$. To control goaf gas emissions in the panel, about $100m^3/s$ of airflow was supplied to the face and a back-return ventilation system was adopted to control the gas levels at return end of the face.

The mine's initial gas control strategy was to pre-drain a larger proportion of gas to reduce gas emissions during longwall extraction. The most intensive pre-drainage programme ever undertaken in Australia was implemented to this effect, reaching 200km of drilling in the second year of operation. However, results revealed that even this extensive pre-drainage was not adequate or economically sustainable, due to the low permeability of the coal seam. There was a need to develop effective goaf drainage technologies suitable for these conditions.

The optimum gas drainage strategies implemented at the mine site include the following:

- New goaf hole designs to improve their performance particularly, in flat structure and strong roof areas and ensure that oxygen levels in the holes was below 5%;
- The relocation of operating boreholes;
- Uniform and continuous operation of goaf holes (sudden peaks and lows in goaf drainage flow rate increases the sponcom risk);
- Goaf holes located at least 80 to 100m away from the dyke/fault areas to improve their performance and also to minimise sponcom risk in these areas;
- Immediate sealing-off of the cut-through's behind the face (i.e. only one cut-through open for back-return);
- Reduction in air velocity on the intake side of the goaf.

During field studies, gas flows from individual goaf plants was around 1,500 to 3,000l/s and total gas flow rate from longwall 4 goaf holes was about 4,000l/s, with oxygen concentrations below 5% for most of the time. It is to be noted that actual goaf plants flow rates were considerably higher than 4,000 l/s. The total goaf flow from longwall 5 panel was around 4,500 to 5,000l/s. Analysis of the results showed that all goaf holes in longwall 5 also performed well, with oxygen concentrations below 5% for most of the time. All the goaf holes in first half of the longwall 5 panel were in operation for almost six months, until the face retreated to the finish line, without any spontaneous combustion problem.

Mine B

Mine B is located in the Bowen basin of Queensland. The mine extracts coal from the 2.0 to 3.0 m thick German Creek seam and produces about 2.5 million tonnes (Mt) annually. The depth of the current workings is about 400 m. The total gas content in the working longwall panel area is in the range of $12m^3/t$ to $14m^3/t$. The longwall panels are 230 m wide and approximately 2,000m long, with a cutting height around 2.8 m.

Over the years, goaf gas emissions at Mine B have increased substantially, with almost a two-fold increase in 2 to 3 years and reached over 1,600 l/s in LW309. In the first few panels, 3 to 7 goaf holes were drilled along the centre line of the panel. The traditional gas drainage strategy was to connect two goaf holes closest to the face to the drainage plant and close off all the remaining goaf holes. With the increase in gas emissions, the density of goaf holes increased substantially, with goaf holes drilled at a close spacing of 100m to control high goaf gas emissions, as shown in Figure 4. However, even after this extensive gas drainage, the longwall panels suffered delays due to gas outages with return gas concentration levels rising above the operational gas limits. An increase in the gas drainage plant's suction pressure was resulting in ingress of face airflow into the goaf holes with no increase in goaf gas drainage flow rates. Analysis of the goaf gas control issues and results indicated that only reducing the goaf hole spacing would not solve the longwall gas problems and there is need for development of more effective gas control strategies.

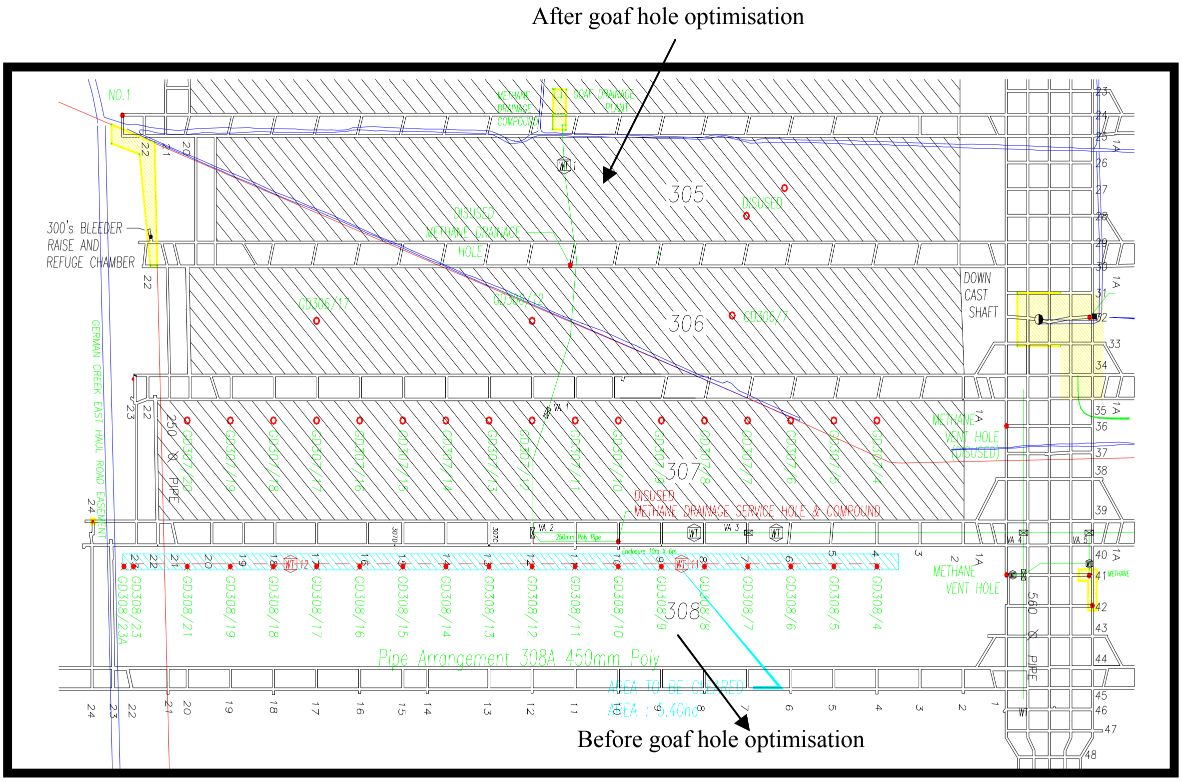


Figure 4 Goaf drainage patterns in Mine B – before and after goaf hole optimisation [4]

The optimum gas drainage strategies implemented at the mine site include the following:

- In addition to the standard gas drainage from goaf holes located close to the face, goaf gas was drained from deep goaf holes located at the start-up area of the panel or from holes located at 1,000 m behind the face.
- An additional goaf fan of 6,000 - 7,000m^3/hr (~2,000l/s) drainage capacity was installed near the start-up area of the panel for deep goaf holes gas drainage.
- The total capacity of goaf drainage plants and fans has been increased from the existing 7,500m^3/hr to 14,000m^3/hr (~ 4,000l/s) to enable the optimisation of drainage strategies.
- Instead of operating at alternate peak flow rates and stoppages, the strategy of continuous operation of deep goaf holes at moderate capacity (300 to 1,000l/s) was implemented.
- Instead of the standard practice of gas drainage from just two holes closest to the face, three to four goaf holes were connected to the goaf drainage plants.

Total drainage flow rate from the goaf plants increased to 5,500 to 6,000m^3/hr compared with 4,500 to 5,000m^3/hr in the previous panels. In addition, a new goaf fan at the start-up area of the panel was draining gas at the rate of about 2,000 to 3,000m^3/hr. The total goaf gas drainage/capture flow rates have reached 1,400~1,800l/s, almost 40% to 60% improvement over the previous panels' goaf holes performance. The optimum goaf gas drainage strategies also resulted in reduced return gas levels at around 1.0%, compared with 1.2 to 2.0% in the previous panels. After adopting new goaf gas drainage strategies, it was also observed that changes in barometric pressures did not affect the tailgate gas levels.

In brief, the implementation of the optimised gas drainage strategies has led to goaf gas capture improvement from 1,500 l/s to 5,000 l/s in Mine A and 40% to 60% improvement in Mine B.

Table 2 shows a summary of the major outcomes for Mine A and Mine B after the implementation of the optimised gas drainage strategies.

Table 2 A summary of demonstration study outcomes in Mine A and Mine B

Mine A	Mine B
• Goaf gas capture tripled (1,500 l/s to 5,000 l/s)	• Gas drainage performance – improved by > 50%
• Successful capture of CO_2 gas	• Panel start-up area gas problem solved
• Spontaneous combustion risk reduced – less O_2 in holes	• Allowed optimisation of LW ventilation system
• Major reduction in mine gas drainage cost	• Goaf gas delays almost reduced to zero
• Improvement in mine/LW productivity	• Improvement in mine/LW productivity

In view of the successful demonstration studies in Australia and the current practices in P1 mine, there is great potential for further improvement for gas recovery by applying some of the advanced Australian technologies. An estimated improvement for gas drainage is given in Table 3.

Table 3 A summary of present and projected gas drainage in P1

Item	Drainage Gas									total drainage flow rate (m3/min)	total CH4 (m3/min)	CH4 %
	Surface goaf hole			Return corner and others			super-adjacent gas gate					
	total flow (m3/min)	CH4 %	total CH4 m3/min	total flow (m3/min)	CH4 %	total CH4 m3/min	total flow (m3/min)	CH4 %	total CH4 m3/min			
Present gas drainage	15	60	9	100	15	15	122	23	28	237	52	22
Estimated gas capture	29	70	20	150	20	30	100	35	35	279	85	31

It is recognised that the mining conditions in Australia are different in many aspects from Chinese coal mines but some technologies, in particularly those used in the demonstration studies, can be adopted and are applicable to the Chinese coal mining conditions, e.g. at the identified P1 Mine, for improved mine gas recovery.

It has been identified during field studies that some fundamental improvements on the existing drainage systems would greatly improve the gas capture purity and flow rate, including borehole positioning and sealing methods, on-line gas flow monitoring and pipeline optimisations. The control of suction pressure is important as a sensitive means of controlling the purity and flow rates in the gas drainage ranges. An improved control of the suction pressure will result in a maximum flow of gas at an acceptable purity out of the explosive range.

2.5 WORK PLAN FOR IMPROVED GAS RECOVERY IN THE CHINESE COAL MINE

Gas drainage has become an essential part of gas management and ventilation system in coal mines in Huainan. Detailed planning of such a system is of prime importance so that effective installations and safety, production and financial returns can be achieved.

In general, the planning of a gas drainage network commences with the estimation of gas emission rates in different sections of the mine and the proportion of the total gas emission which can be drained, followed by the calculation of drainage networks, selection and construction of the networks and extraction plants, and finally the supervision and management of the networks.

Gas drainage requirements are determined on the basis of production level and expected gas emission rates. The likely variability in gas flow and purity can be obtained from a study of the mine development plan, the geological conditions, seam gas content data and historical gas emission data. The drainage system needs to be designed to accommodate the maximum captured gas mixture flows from all sources in the mine including working faces and seal-off/abandoned areas.

The identified P1 Mine in this study has already had a coal mine methane drainage system in operation. Whilst some effective methods and systems are in place there is still a need to improve these further and integrate them more into the design and day to day management of the mine. Benefits can be achieved by the introduction of advanced monitoring systems and the above integrated approach. Reliability of gas supply and gas purity can be increased by obtaining gas from different sources in this area, or from more than one mine.

On the basis of field observations and analysis of available data, the following preliminary work plan has been proposed specifically for improving gas recovery at P1 mine:

Stage I: Estimation of gas reservoir volume and emission levels into workings

This can be achieved by critical examination and review of the mining and geological setting including gas content data and geological strata sections, current coal production and relevant gas emission data in the mine. Advanced computer modelling studies (such as COSFLOW) will be needed to provide gas emission rates for different working panels at the mine.

Stage II: Estimation of improved gas drainage extraction levels

Work at this stage will involve a detailed analysis of gas drainage facilities and methods, gas pipelines and holders, gas quantity and purity at the mine, in particular the gas drainage methods developed at Huainan area. The work will also involve the selection of drainage methods (surface and underground) forming the drainage ranges of the network. Practical considerations would include:

- Primary gas sources in roof and floor strata;
- Effectiveness of drilling patterns;
- Sealing of drainage holes/standpipes;
- Rates of production advance;
- Design and layout of the main gas collection pipelines;
- Optimum drainage parameters including suction pressure;
- Close control and management of the drainage systems.

Stage III: Improved design of gas drainage systems

The objective of the improved design of gas drainage systems at P1 mine is to improve both the drainage gas purity (CH_4 levels), stability and flow rate (m^3/min) by making full use of the current drainage capacity (433m^3/min). Work at this stage will involve the design and optimisation of both underground drainage boreholes and surface goaf holes. For underground drainage, the focus will be the improvements of the positioning and sealing of the drainage boreholes to maximise methane gas capture whilst reducing total gas flow dilution caused by air leakage. An integrated approach involving several advanced techniques developed by CSIRO will be deployed in this process, including:

- Coupled geo-mechanical and gas flow modelling (COSFLOW) to obtain a detailed understanding of the strata caving/deformation mechanisms and gas emissions around the longwall panels/roadways to assist in the design of gas drainage systems. This information is important to optimise the borehole location/orientations to achieve maximum borehole stability and gas capture efficiency;
- Gas flow studies using Computational Fluid Dynamics (CFD) models to provide scientific understanding of gas migration patterns as well as air ingress/leakage into boreholes due to suction applied to the drainage ranges and to optimise borehole drainage patterns and suction pressures.

Stage IV: Implementation and monitoring of the improved gas drainage designs

Work at this stage involves the drilling and completion of the improved underground drainage boreholes designs as well as surface goaf holes. Work will also involve the commissioning of the upgraded drainage networks, the connection of newly drilled boreholes and the extending ranges. A key part of the work is the implementation and supervision of the improved underground borehole sealing operations and the completion process of the surface goaf hole(s) in the longwall panels. Concurrently a robust monitoring system should be installed in conjunction with the implementation of the drainage designs, including:

- Instrumentations for monitoring surface goaf hole stability;
- Instrumentations for monitoring borehole sealing, and if necessary, tracer gas studies to investigate air tightness of boreholes and drainage collecting ranges;
- On-line monitoring systems to provide timely information of drainage network flow rate, gas purity (compositions), and suction pressures.

Stage V: Assessment and prediction of gas drainage system performance for utilisation

Work at this stage will involve the overall assessment of the system performance in view of mine gas production and prediction of the targeted drainage results for utilisation, in particular, drainage gas purity (CH_4%) and flow rate (m^3/min). Factors influencing the drainage performance will be closely examined based upon the monitoring data and file operational experience and gaps identified for further improvements.

It is anticipated as a result of the implementation of the above project plan, the gas drainage efficiency, both in terms of gas purity and flow rate, will be increased significantly to a level that is suitable for power generation as discussed in Case Study B. In addition, a more reliable and robust mine gas production and prediction package, which is currently not available for underground coal mines and associated development of coal mine methane drainage and utilisation schemes, will be developed. This package will serve as an integrated planning and decision-making support tool for mine gas management and coal mine methane utilisation/mitigation project developments.
It must be noted that the above work plan is preliminary and a more detailed project plan can only be developed in close consultation with the mine and adjusted accordingly in view of the work progress. It is recommended that the work should initially be focused on solving the stability of the boreholes (both underground and surface), the low purity and flow rate problems with the current drainage systems and for which a more detailed work programme be formulated with P1 mine.

2.6 PRELIMINARY EVALUATION OF PROJECT ECONOMICS

The major cost items of a new drainage system in a mine would typically include:

- The surface extract plant;
- Gas holder(s);
- Mine pipe ranges and fittings;
- Installation of pipes and fittings in shafts and main roadways;
- Drilling machines, drill rods, bits, standpipes and borehole equipment, sealing materials;
- Pumps for wet drilling;
- On-line drainage network monitoring system.

These costs depends on a number of factors, including the depth of mining (shaft), distance of the districts to extraction plants, pipe diameters, method of monitoring and control etc. A quantitative economic analysis of the project is beyond the scope of this study, however it can be anticipated that the capital cost should be low because much of the gas drainage infrastructures are in place already in P1 mine. The proposed project would involve the expansion and upgrade of the current gas drainage facilities, including construction and installation of pipeline networks, auxiliary equipment and on-line gas drainage monitoring systems.

Presently the bottleneck for the use of the drainage gas at P1 mine is the low purity gas from underground drainage systems. A key part of the project would involve the design and improvement of the current drainage borehole drilling and sealing practices to reduce air leakage into the drainage holes.

Below is an example of plant potential increase of drainage gas fired gas engine plant when the drainage gas quality and quantity improvement are as projected in Table 3. For this conceptual gas engine power plant, best gas engine technology (e.g. GE Jenbacher) is selected for which minimum CH_4 concentration requirement is 25%, and its electrical efficiency is ~40% for 1.4-2MW gas engines. The plant potential is determined below:

- Based on CH_4 emissions from current drainage gas practice
  - ~28% of drainage gas from return corner and others with 15% CH_4 can be mixed with surface goaf hole and super-adjacent gas gate drainage gas to achieve 25% CH_4.

- Pure CH_4 flow rate for the gas engine plant: 41.2m^3/min
- Plant size is 24.7MW_t, and annual electric production is 82,333 MW·hr.

o After estimated drainage gas system improvement
- All of the drainage gas can be used with average CH_4 concentration of 30.5%,
- Pure methane flow rate increased to 85 m^3/min for the gas engine plant,
- Plant size is 51MW_t, and annual electric production is 169,769 MW·hr.

Figure 5 compares the power plant size and annual electricity production. It is obvious that the annual electricity production is doubled after the projected drainage gas system improvement.

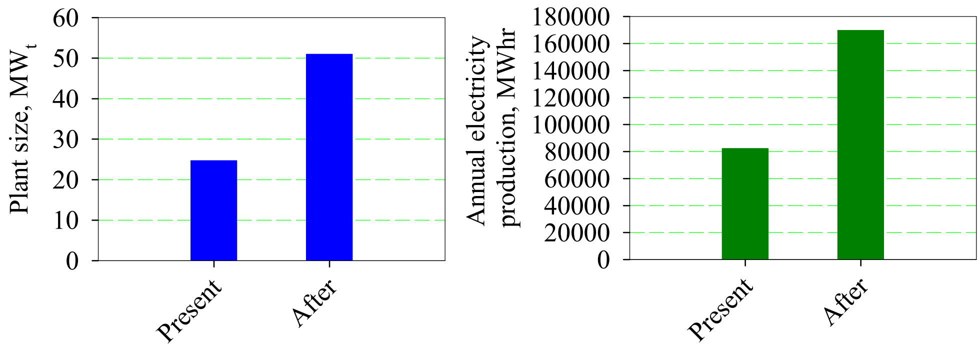


Figure 5 A comparison of the gas engine power plant potential

2.7 CONCLUSIONS FOR CASE STUDY A

Cast Study A aims to provide an overview of the gas drainage practices in a typical Chinese coal mine and the technological know-how in Australia that could be deployed in China to improve mine gas drainage efficiency for utilisation.

A Chinese coal mine, known as P1, located in Huainan coal mining area in Anhui province of China, has been identified for this study. A range of gas drainage techniques have been used in this mine but the purity and flow rate of the drained gas flow are well below the desired level for power generation purpose as discussed in Case Study B. A number of factors have been identified for further improvements, these include the sealing practices of the drainage boreholes, the location of the drainage holes (both underground and surface) and the lack of an on-line monitoring system for the effective management of the drainage networks.

An integrated approach has been developed by CSIRO involving advanced computer modelling of strata behaviour, gas emission, goaf gas flow patterns as well gas characterisation techniques. In combination with field studies, this approach has proved to be a powerful tool for improving goaf gas capture and overall gas management strategy in several Australian underground coal mines.

For P1 mine, there is great potential for further improvement of gas recovery by applying some of the advanced Australian technologies. With the existing drainage capacity and infrastructure in the mine, it is anticipated both the total gas flow rate and methane concentration can be increased by improving the design of the drainage boreholes, borehole sealing practices, pipeline joints as well as the installation of an on-line monitoring system.

On the basis of field observations and analysis of available data, this study has proposed preliminary work plan for improving gas recovery at P1 mine. A more detailed project plan will have to be developed in close consultation with the mine and adjusted accordingly in view of the work progress. Successful implementation of the project plan will significantly improve gas drainage efficiency to a level that is suitable for an economically viable gas utilisation project.

3 CASE STUDY B

EFFECTIVE CAPTURE AND UTILISATON OF VENTILATION AIR METHANE FROM A TYPICAL CHINESE COALMINE

3.1 OVERVIEW OF VAM TECHNOLOGIES

The low concentration of methane in mine ventilation air and in mine drainage gas (especially in China) presents a major challenge for utilisation and mitigation, and requires either treatment in its dilute state, or concentration to levels that can be used in conventional methane-fuelled engines. As mentioned above, it is estimated that approximately 70-80% of the drainage gas in China has a methane concentration of less than 30%. Effective technology for increasing the concentration of methane is not currently available but is being researched. Most work has focussed on the oxidation of very low concentration methane. These processes may be classified as either thermal oxidation or catalytic oxidation, based on the combustion kinetic mechanisms. Table 4 summarises major ventilation air methane mitigation and utilisation technologies, which have been explored in the past, in terms of fundamental mechanisms, technical principles and applicability. Utilisation technologies of ventilation air methane are generally divided into two basic categories: ancillary uses and principal uses as shown in Table 4.

3.1.1 Ancillary uses

Ancillary uses of mine ventilation air typically involve it being uses as a substitute for ambient air in combustion processes, such as power stations, industrial furnaces or other combustion apparatus. Generally, it is fairly certain that the methane will be combusted in these plants and the energy from methane combustion will be usefully recovered within the existing process. A major issue is the safe connection of these units to mine shafts, but this is site specific and has not been fully examined and demonstrated. There should be no problem with dust in ventilation air when used in pulverised coal-fired power stations or similar combustion equipment. Unfortunately, there are not always pulverised fuel (p.f.) power stations or other combustion units adjacent to mines, which limits the applicability of this technique.

A pilot-scale study has been carried out at the Vales Point Power Station (NSW, Australia) to determine the feasibility of this approach. It has been reported that this technique is technically feasible, especially if the power plant already exists or will soon be built near a mine ventilation shaft. A full-scale demonstration of this technique at this power station was planned with the support of an Australian federal government program in 2003. In this demonstration the ventilation air was to be fed at a rate of approximately $220 m^3/s$ into the intake of the power station. Total air consumption for the 2 × 660 MW pulverised coal fired boilers at the power station is approximately $1200\ m^3/s$. Unfortunately, this project is no longer operational, from which it can be assumed that there were some issues that resulted in termination of the project.

The operation of 54 one-megawatt Caterpillar G3516 spark-fired engines at Appin Colliery has demonstrated that methane from ventilation air contributes between 4 and 10 percent of engine fuel, corresponding to the consumption of approximately 20% of the ventilation emissions. However, these gas engines do not take the mine ventilation air anymore due to ventilation air cleaning issues. Conventional gas turbines give similar performance to gas engines and the methane from ventilation air will only contribute a small percentage of the turbine's fuel. Moreover, the use of this air for combustion dilution and cooling of the turbine inlet scroll and first stage in the conventional gas turbines will result in a significant fraction of the methane passing through the turbine without combusting. In general, the use of mine ventilation air by internal combustion engines and conventional gas turbines is restricted by the supply of the primary fuel, which is usually medium-quality drainage gas. Therefore, these engines and turbines are not good candidates for destroying and utilising methane in ventilation air.

Table 4 Current development of technologies for ventilation air methane

Technology	Principle	Application status
Ancillary uses		
Thermal oxidation		
Combustion air for conventional p.f. power station	Combustion in p.f. power station boiler furnace	Mitigation Utilisation – demonstrated in a pilot-scale unit, and being considered for a full-scale demonstration
Combustion air for gas turbine	Combustion in conventional gas turbine combustor	Mitigation Utilisation – studied
Combustion air for gas engine	Combustion in gas engine combustor	Mitigation Utilisation – demonstrated
Principle uses		
Thermal oxidation		
Thermal flow reverse reactor (TFRR)	Flow reverse reactor with regenerative bed	Mitigation – demonstrated Utilisation – not demonstrated yet at a mine site
Recuperative gas turbine	Gas turbine with a recuperative combustor and a recuperator	Mitigation – demonstrated Utilisation – demonstrated in a pilot-scale unit, and need for further modifications (?)
Catalytic oxidation		
Catalytic flow reverse reactor (CFRR)	Flow reverse reactor with regenerative bed	Mitigation – demonstrated Utilisation – not demonstrated yet at a mine site
Catalytic monolith combustor (CMR)	Monolith reactor with a recuperator	Mitigation – demonstrated Utilisation – not demonstrated yet at a mine site
Catalytic lean burn gas turbine	Gas turbine with a catalytic combustor and a recuperator	Mitigation – combustion demonstrated Utilisation – being developed in a lab-scale unit
Enriching processes		
Multi-stage fluidised/moving bed concentrator	Adsorption (using activated carbon), and a desorber	Mitigation & utilisation – the development has stopped in 2004.
Gas centrifuges	Centrifugal	Mitigation & utilisation – being proposed as a concept.

3.1.2 Principal uses

Principal use technologies are defined as those that which are intended to use the VAM as the major source of methane in the process. It should be noted that some technologies in Table 4 require supplementary high quality fuel when recovering energy to generate power if the methane concentration in the VAM is too low.

*3.1.2.1 **Flow reverse reactors***

Both the Thermal Flow Reverse Reactor (TFRR) and the Catalytic Flow Reverse Reactor (CFRR) employ the flow-reversal principle to transfer the heat of combustion via a solid medium to the incoming VAM in order to raise the temperature to the ignition temperature of methane. The two systems differ only with respect to the use of a catalyst. There is no doubt that the TFRR, CFRR and CMR technologies are technically feasible options in the mitigation of ventilation air methane when the CH_4 concentration in air exceeds the minimum requirement and the economic performance is not important. The main limitation of TFRR and CFRR systems is that it is difficult to extract useful energy for power generation. It should be possible to recover surplus heat from the systems when they are operating with methane concentrations above a minimum value, perhaps 0.9% based on reported results to date [5]. This heat then needs to be transferred into a working fluid, such as hot water/steam for a steam turbine or air for a gas turbine. However, extraction of heat from the reaction zone is complicated by high temperatures, while the flue gas temperature tends to oscillate through excessive ranges that prevent stable power production.

Trials in a small pilot-scale TFRR unit, attached to the ventilation air shaft of Appin Colliery, were carried out by Danell *et al*. [6]. They reported that the unit can be operated with CH_4 concentration as low as 0.19%, however, they did not report how long the operation lasted at such concentration or whether it was sustainable at this level. Indeed, this is a very practical issue for mine-site operations as the methane in ventilation air could be lower than 0.19% at times. Similarly, it is unclear how long the CFFR unit can be operated on 0.1% methane in air.

The West Cliff Colliery (WestVAMP) project was expected to be the world's first large-scale VAM-base power production project. Its commercial operation was planned for mid 2006. It was planned to capture and use for electricity generation approximately 20 percent of the overall ventilation air exhaust flow from the mine, i.e. the two large units will consume approximately 57.5 m^3/s of ventilation air. It will provide greenhouse gas emission reductions of approximately 200,000 tonnes per year of CO_2 equivalent. The unit will use drainage gas from the mine to even out fluctuations in the ventilation air in order to maintain the concentration entering the unit at 0.9%.

3.1.2.2 ***Monolithic reactors***

The Catalytic Monolith Combustor (CMR) technology utilises a honeycomb-type monolithic reactor, and is known for its outstanding characteristics of very low pressure drop at elevated mass flows, high surface area, and high mechanical strength [7]. Therefore, the honeycomb monolithic type reactor is better for power generation applications [8, 9, 10]. Compared with the TFRR and CFRR units, the CMR unit should be more compact for the same volumetric flow of ventilation air. However, in contrast to the regenerative beds of the TFRR and CFRR units, a recuperator is needed to pre-heat the ventilation air. According to the experimental catalytic combustion results from a CMR laboratory-scale rig, the CMR can be continuously operated when methane concentration is greater than 0.3% and the air is preheated to 500°C by a recuperator using flue gas from the CMR. It is therefore likely that the CFRR requires similar conditions for continuous operation.

The above mentioned flow reversal reactor process uses packed bed reactors. The pressure drop of equivalent packed bed reactors is very high compared to the monolith design. Monoliths consist of a structure of parallel channels with walls coated by a porous support with catalytically active particles, as shown in Figure 6. The monolithic structure is normally ceramic, but may also be metallic, and acts as a substrate for a washcoat slurry of base metals (such as alumina) on which catalytic material (typically noble metals such as palladium or platinum) are placed. Moreover, the monolith open structure lends itself to use in applications where dust is present, even in high dust environments, such as coal-fired power plants and diesel exhausts, without concern for plugging. The characteristics of the monolithic reactor have been evaluated in detail in Ref. [11].

3.1.2.3 ***Lean burn gas turbines***

Lean-burn gas turbines being developed in the world include Energy Development Limited (EDL)'s recuperative gas turbine, CSIRO lean-burn catalytic turbine and Ingersoll-Rand (IR)'s microturbine with a catalytic combustor.

The EDL recuperative gas turbine is designed to operate continuously when the methane concentration in air is above 1.6%, which leads to the air being preheated to 700^{o}C before combustion. It requires the addition of substantial quantities of methane to the ventilation air to reach adequate methane concentrations. Announced on 17 May 2001, EDL will install and operate four 2.7MW$_e$ recuperative gas turbine generators at Anglo Coal's German Creek Mine (Queensland, Australia). These gas turbines are modified Centaur units from Solar Turbines. However, development of EDL recuperative gas turbine technology has ceased due to difficulties in supplying a recuperator that is substantial enough to give the required heat transfer and instability in the combustor and control system.

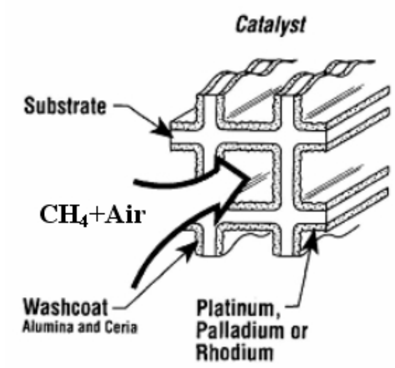


Figure 6 Illustration of a monolith reactor [12]

Reduction of the minimum methane concentration at which a turbine system can operate has substantial advantages in reducing the reliance on supplementary fuels. CSIRO [13] devised a 1% methane catalytic combustion gas turbine system (VAMCAT) based on methane catalytic combustion experimental data and the design criteria for a turbine system. A 1% methane turbine can use a much greater proportion of ventilation air compared with a 1.6% methane gas turbine, which allows mitigation and utilisation of most of the VAM through lean burn catalytic turbines for typical gassy mines. Thermodynamic analyses indicate lean-burn catalytic turbines can be operated at lower methane concentrations, perhaps to 0.8%, but it is difficult to generate power efficiently below this concentration. Moreover, it can be run at a higher methane concentration of up to 1.6%, depending on application site specifications. At present, under support of the Bilateral Climate Change Partnerships Program between Australia and China, and the Australia China Special Fund, a 20-30KW$_e$ prototype unit is being developed to demonstrate a lean burn catalytic turbine, which can be powered with about 1% methane in air.

In addition to the 1% methane turbine development in Australia, Ingersoll-Rand in the USA was also trying to develop a microturbine with a catalytic combustor powered with 1% methane in air.

3.1.3 Enriching processes

To date, two types of VAM enriching processes have been investigated or reported. They are: (1) multi stage fluidised/moving bed concentrator [1], and (2) gas centrifuges [14].

Enriching processes (concentrators) have been applied to several industries to capture volatile organic compounds. It would be an absolute need that a concentrator of this type could be used to enrich dilute methane in mine ventilation air to levels that meet the requirements of lean-burn methane utilisation technologies, such as catalytic and recuperative gas turbines. This involves taking the 0.1 to 0.9% methane stream and increasing the methane to a concentration of greater than 20%. If the methane can be concentrated to approximately 30% or higher, conventional gas turbines can be employed to generate electricity without significant modifications. In addition, the concentrator could act as a buffer to cope with variations in methane concentration and ventilation air flow rate. However, it remains to be proven that the enriching process concept is scientifically, technically and economically feasible for dilute methane.

Environmental C & C, Inc. (ECC) manufactured a fluid bed concentrator and conducted tests on that system's efficiency using simulated ventilation air with 0.5% CH_4 [1], including selection of the most efficient adsorbent medium for the process. The concentrator consists of an adsorber, a storage vessel for the adsorbent medium with the adsorbed methane, a desorber and a transporting/feeding system for the adsorbent medium. The adsorber is a hybrid multistage fluidised/moving bed, consisting of a series of adsorbent medium fluidised beds. The ventilation air enters from the bottom of the adsorber, passing upward through the fluidised beds. The adsorbed methane makes the adsorbent medium denser, causing the saturated adsorbent to drop to the bottom of the adsorber, where it can be discharged to the storage vessel and then the desorber. The medium is regenerated by increasing the temperature, which results in the release of concentrated methane into a low volume stream. The adsorbent medium is then recycled back to the adsorber for reuse. In general, the best adsorbents are activated carbons, but zeolites also may be suitable. Unfortunately, recent experiments conducted by ECC on an adsorbent in a fluidised bed concentrator were disappointing, and the trials have stopped [5].

At the M2M coal mine technical subcommittee meeting held in Geneva on 27-28 April 2005, Bose Research and Development, Inc. introduced a gas centrifuge concept of enriching the dilute methane in ventilation air [14]. Theory of separation in a gas centrifuge is that which gas stream spinning in a vortex at high velocity inside a cylindrical chamber, centrifugal force acts more strongly on higher weight molecules. So, lighter molecules concentrate at the core, and the heavier molecules at the outer periphery. The gas centrifuge separation method is extensively used for isotope uranium enrichment in many countries [15]. It is very interesting to notice that van Wissen et al. [16] studied the separation of carbon dioxide and methane in continuous countercurrent gas centrifuges as a way of purifying natural gas. They reported that an issue is that the difference in molecular weight is relatively small with the CO_2 and CH_4 gas centrifugal separation in contrast to the uranium isotopes separation with large differential molecular weight. A peripheral velocity of approximately 800m/s is needed to achieve some separation between CO_2 (44) and CH_4 (16). Or a centrifuge is required in the range of 32,000-100,000 rpm with rotor radius of 7-9cm. They concluded that it is certain that the gas centrifuge would not generate enough revenue to justify the high investment costs. Therefore, it could be imaged how hard it would be to 'enrich' the diluted methane (16) in ventilation air of oxygen (32) and nitrogen (28) using gas centrifuge.

A successfully demonstrated, cost-effective concentrator would be a breakthrough technology for application in mine ventilation air processing. CSIRO is currently investigating a new concept for enriching the methane in ventilation. However, no practical results are available for reporting at this time.

3.1.4 Thermodynamics

No matter what technology has been or is currently being developed for the capture and utilisation of mine ventilation air methane, it has to obey the laws of thermodynamics. In general, the most important questions that we need to answer on the abovementioned VAM technologies and other proposing concepts are: (1) what is the minimum methane concentration required for the VAM-only mitigation technologies? (2) what is the minimum methane concentration required for the VAM mitigation and utilisation (power generation) technologies? In order to answer these questions, CSIRO is conducting thermodynamic analysis for each technology/any new concept, which is partly funded by ACARP. Figure 7 shows calculation results of power consumption for compression of $1m^3/s$ of air (1atm, 25°C) with the stated adiabatic efficiencies of 75% and 85%, respectively, determined using HYSYS.Process.

Based on the data in Figure 7, assuming that ventilation air flow rate from a coal mine is $300m^3/s$ and its average methane concentration is 0.5%, the power consumption for compressing such ventilation air flow for a VAM capture and utilisation process to 2atm is 28.86MW. We further assume that all of the methane is captured in high concentration stream for power generation with an efficiency of 40%, output power is $300m^3/s \times 0.5\% \times 36MJ/m^3 \times 40\% = 21.6MW$. Hence, it is clear that the power produced from the captured methane is less than the power used for the compression. It means that this process needs extra power for its operation, and is not economic unless some form of carbon credit revenue is applied to compensate for operating costs and generate some profit.

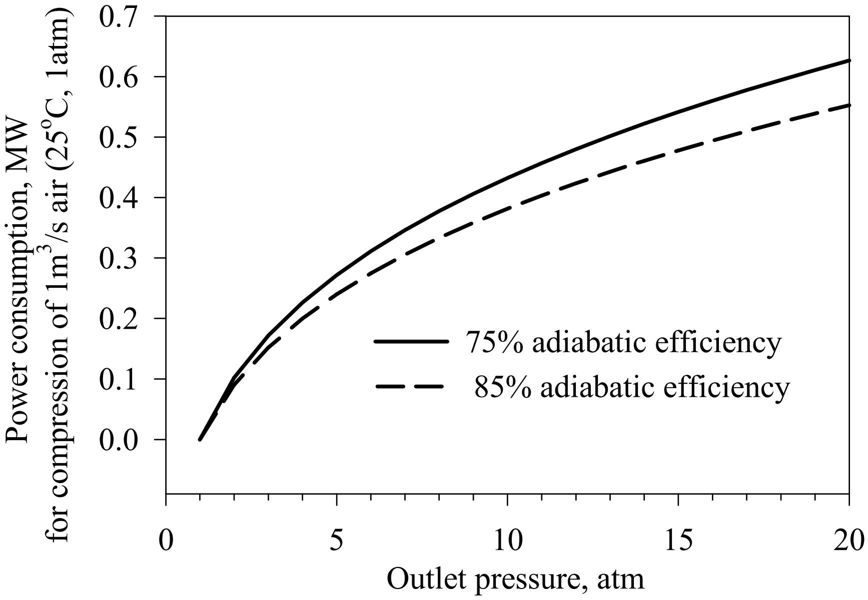


Figure 7 Power consumption for air compression

3.2 POTENTIAL VAM TECHNOLOGIES FOR A CHINESE MINE

3.2.1 Mine methane emissions from a Chinese coal mine

To assess the technical and economic feasibility of a mine-site implementation of any potential mine methane technology, it is necessary to first understand the mine methane emission characteristics from that mine. In order to determine the potential to continuously operate mine methane mitigation and utilisation plants at a mine, mine-site data on the following is required:

- Percentage of methane emitted from ventilation air stream,
- Variations in methane concentration and flow rate for ventilation air, pre- and post-drainage gas if any, and
- Rate of change of methane concentration.

Figure 8 shows the characteristics of methane emissions from a Chinese mine. As shown in this figure, based on the average values from 1 September to 30 November 2004 (91 days), the characteristics of methane emissions can be summarised in the following statements:

- Methane emissions: 25,374,456m^3/year from the ventilation air; 528,221,885m^3/year from the drainage gas.
- Percent of methane emitted from the ventilation air is 4.6%.
- Average methane concentration in ventilation air: 0.52%.
- Average methane concentration in the drainage gas: 22.1%.
- Average pure methane flow rate of the drainage gas: 16.4m^3/s.

As shown in Figure 8, variations of methane concentration and flow rate are not so significant for both ventilation air and drainage gas. Apparently, due to gas drainage technology different to

Australia, the methane concentration of drainage gas is very low. It should be pointed out that this coal mine is one of very gassy mines in China; and the percentage of methane emitted from ventilation air is much lower than the ~64% for typical Australian gassy mines. Major reasons are outlined below:

- This mine is a multi-seam mine, and the main purpose of mining the current seam is to deliberate drain gas from surrounding seams of high gas content;
- A special rock tunnel is built above or below the mining seam for the sole purpose of draining gas from adjacent coal seams;
- Ventilation air is only used for the mined seam.

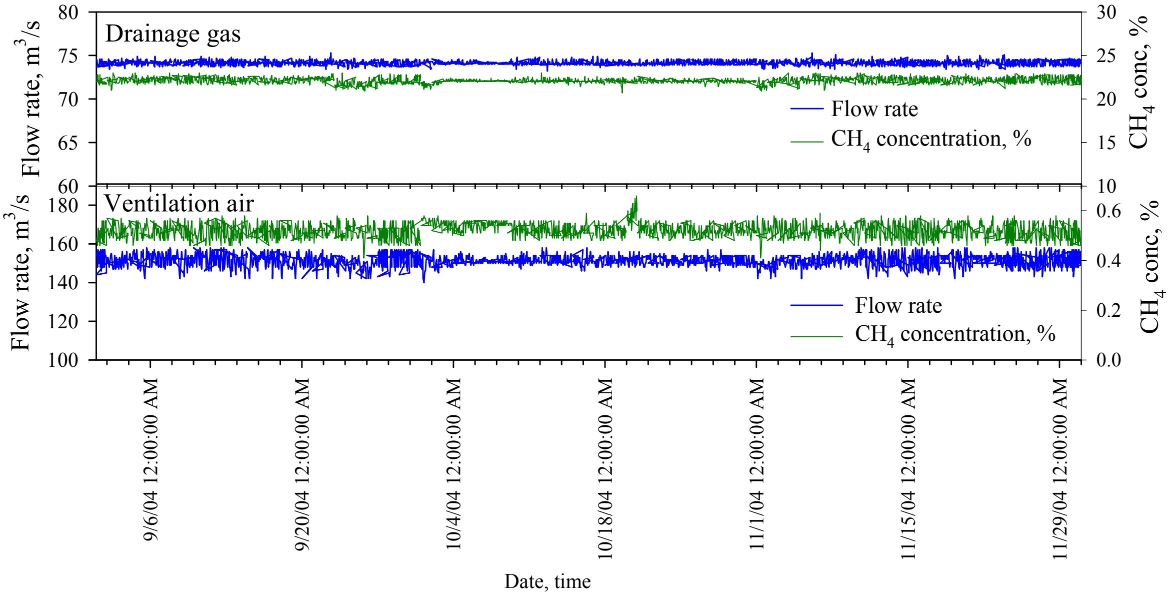


Figure 8 Characteristics of methane emissions from a Chinese mine

3.2.2 Base for the economic assessment

Regarding each technology, it is necessary to determine the potential to continuously operate the plants at the subject mine with over 95% availability, the maximum capacity of the plants at the mine, and then the operating status for each plant. Based on technical specifications, such as operating parameters and capacity determined based on the mine-site data, preliminary economic assessments will be carried out to identify most profitable technology for the coal mine. It should be noted that when any of the power plants being assessed use ventilation air, they are considered to be installed near the ventilation air shaft, and then a pipeline is needed to transport drainage gas to the plants (if drainage gas is required for plant operations). Preliminary economic calculations for the plants use the following characteristics for the basic analysis:

- Plant lifetime: 25 years,
- Installation cost: 10% of equipment capital cost,
- Discount rate: 7.5%,
- Electricity price: RMB400/MW·hr*,
- No carbon credit.

The operating and maintenance costs are also considered during the preliminary economic analysis, and the analysis is based on the Australian electricity market. Another case is considered based on payment of carbon credit as given below:

- Carbon credit: RMB38/tCO_2-e*,

* They are current market prices at a Chinese coal mine. Currency conversion rates are: 1Euro = 9.5411RMB, 1A$ = 5.9257RMB.

3.2.3 Generic conceptual plant design for each technology

This section presents generic system configurations for all technologies regarding VAM mitigation and utilisation in this case study, and for the drainage gas as well.

3.2.3.1 System configurations for VAM mitigation

As discussed in Section 3.1 of this report, the flow reverse reactors and the monolith reactor are considered in this case study. VAM ancillary use (as combustion air) technologies are not yet considered in the case study because there is no information on power stations available for such assessment. It is assumed that the ventilation air can be considered for gas engine power plant when it can use drainage gas from the same coal mine. Figure 9 shows generic conceptual designs of TFRR, CFRR or CMR VAM mitigation plants at a coal mine.

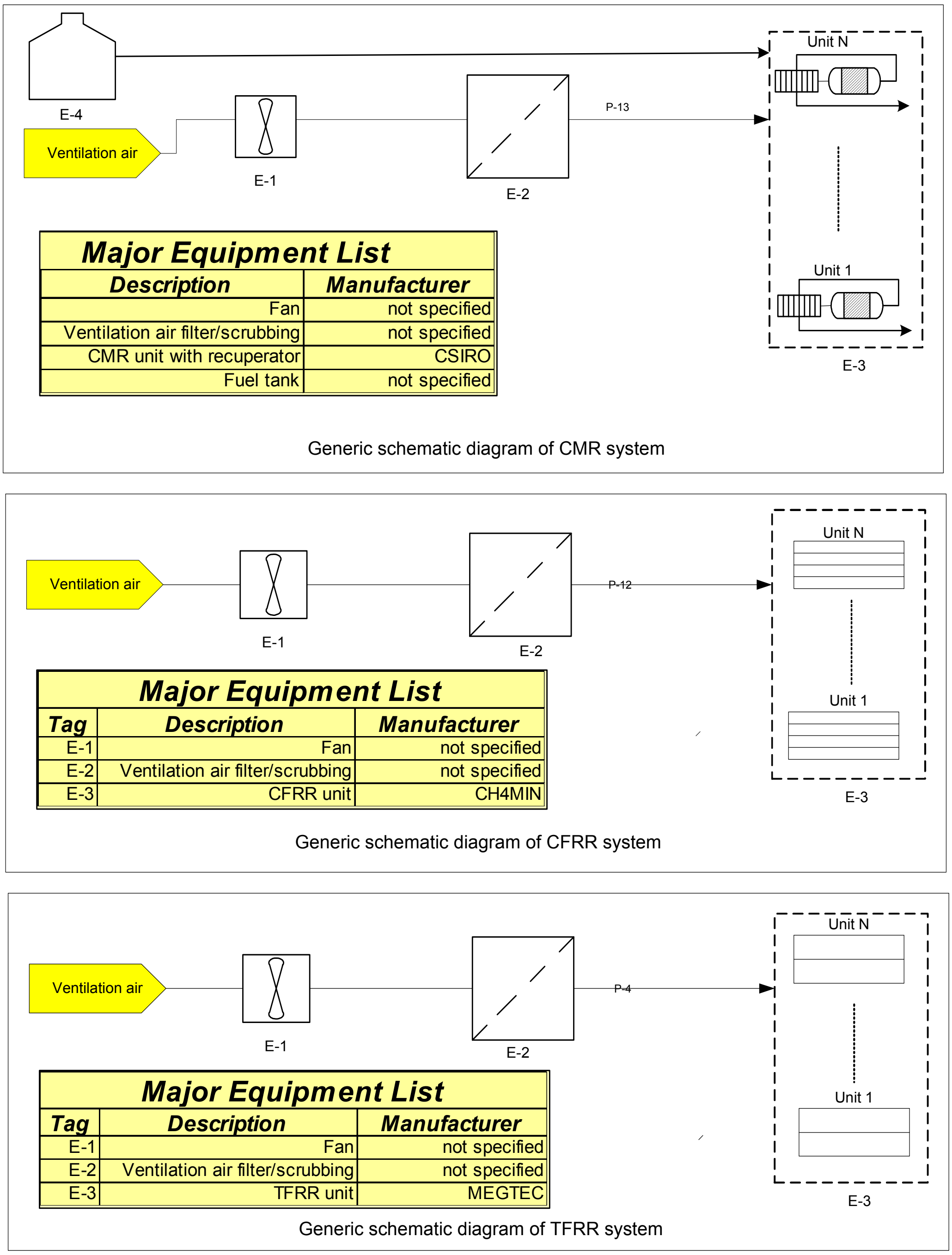
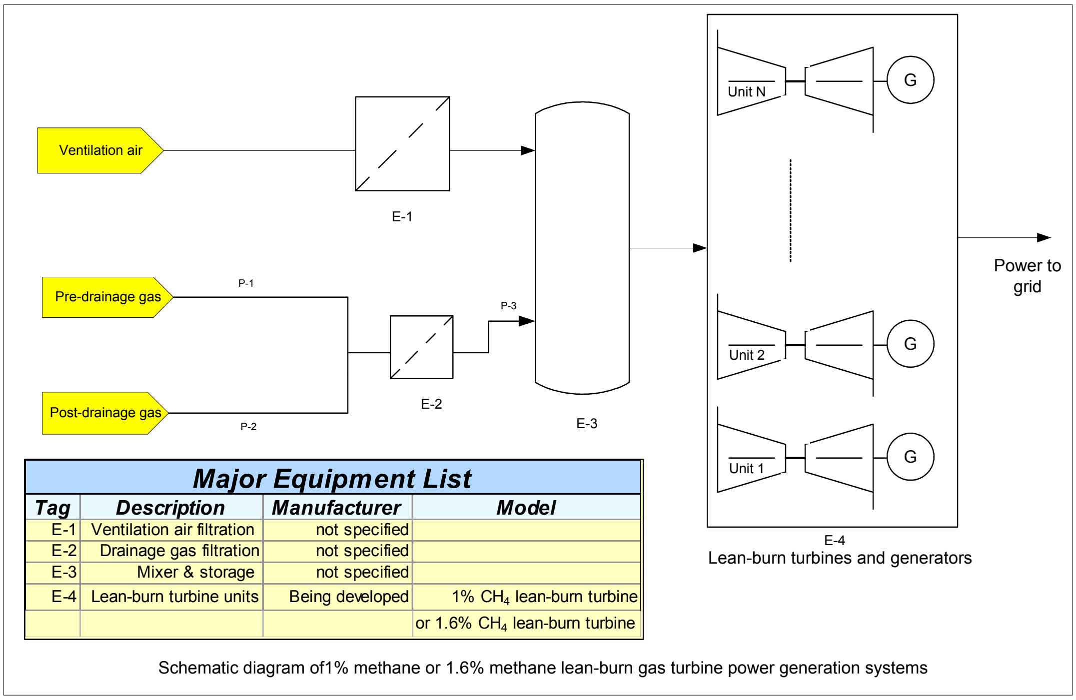


Figure 9 Configuration diagrams of TFRR, CFRR or CMR VAM mitigation plant systems

3.2.3.2 System configurations for VAM utilisation

As discussed in Section 3.3, two types of lean burn gas turbines: 1% CH_4 and 1.6% CH_4, are considered for VAM utilisation in the case study. Figure 10 shows generic conceptual design of VAM utilisation lean burn gas turbine plant at a coal mine.



Tag	Description	Manufacturer	Model
E-1	Ventilation air filtration	not specified	
E-2	Drainage gas filtration	not specified	
E-3	Mixer & storage	not specified	
E-4	Lean-burn turbine units	Being developed	1% CH_4 lean-burn turbine
			or 1.6% CH_4 lean-burn turbine

Figure 10 Configuration diagram of VAM utilisation lean burn turbine power plant system

3.2.3.3 System configurations for drainage gas utilisation

It is feasible to establish a stable flame when the heating value of the drainage gas is greater than approximately 10MJ/m^3, which is equal to approximately 30% methane. As an example, currently, a minimum heating value of 31.5MJ/m^3, which corresponds to the methane concentration of 87.5%, is required for the operation of the Solar Turbine CENTAUR 40, which is an example of the conventional gas turbines. Hence, certain modifications to the gas turbine combustors are required when the methane concentration is less than 87.5%. In the following analysis of the case study it is assumed that modified CENTAUR 40 gas turbines are suitable for burning the drainage gas with 30% methane for the technical and economical assessment, but no ventilation air can be used by the turbines. Figure 11 shows a general conceptual design of drainage gas fired turbine plant at a coal mine.

As mentioned above, the best gas engine technology, developed by GE Jenbacher, promises to use a CH_4 content of 25%. As an example, 1MW_e Caterpillar G3516 spark-ignition gas engines, which are commercially available and have been demonstrated at Appin Colliery, were chosen for the case study. Figure 12 is a generic conceptual design of G3516 gas engine power generation plant at a coal mine when methane concentration is not less than 40%.

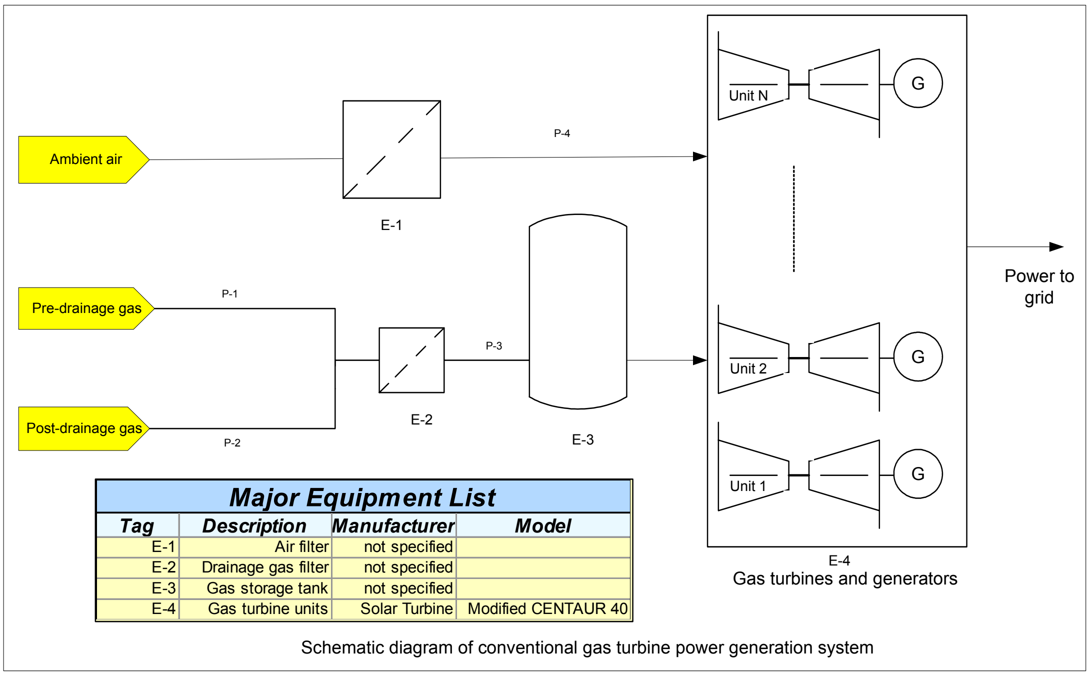


Figure 11 Configuration diagram of drainage gas fired turbine power plant system

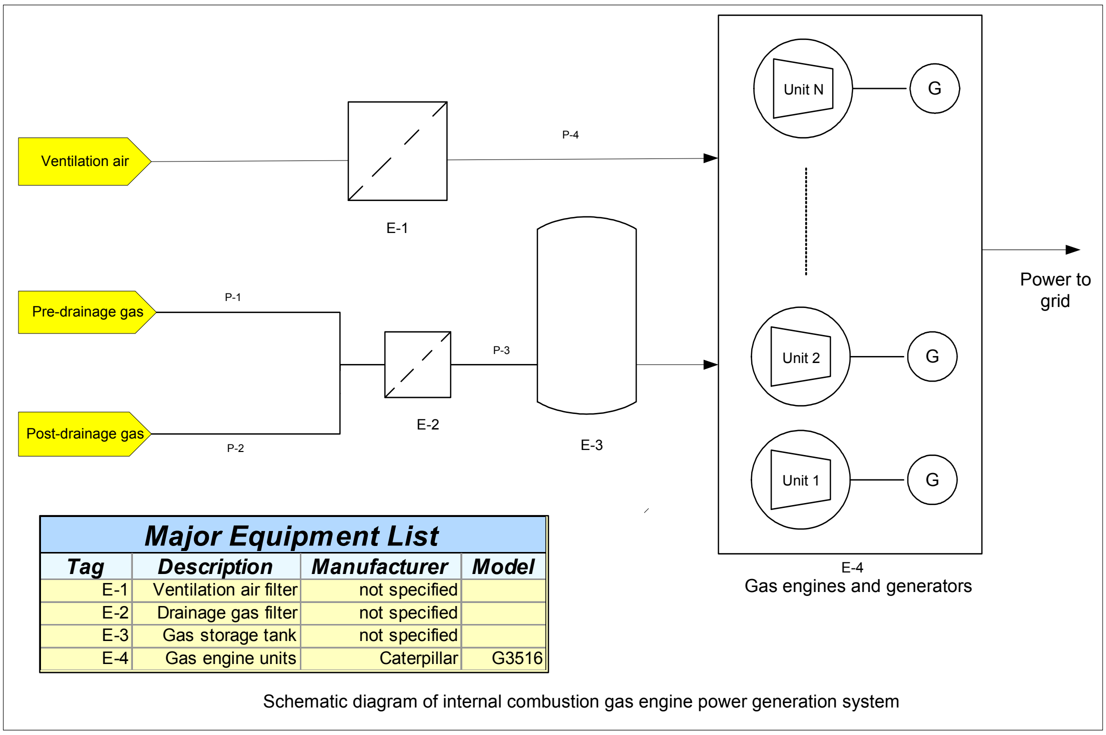


Figure 12 Configuration diagram of drainage gas engine power plant system

3.2.3.4 System configuration for maximum utilisation of drainage gas and VAM

As discussed above, the combined system of lean burn gas turbines and conventional gas engines can be used to achieve the maximum utilisation of drainage gas and ventilation air methane with highest efficiency and output. Figure 13 is a generic conceptual design of the combined lean burn turbine and gas engine power plant at a coal mine. The lean burn turbine could be 1% methane turbine or 1.6% methane turbine.

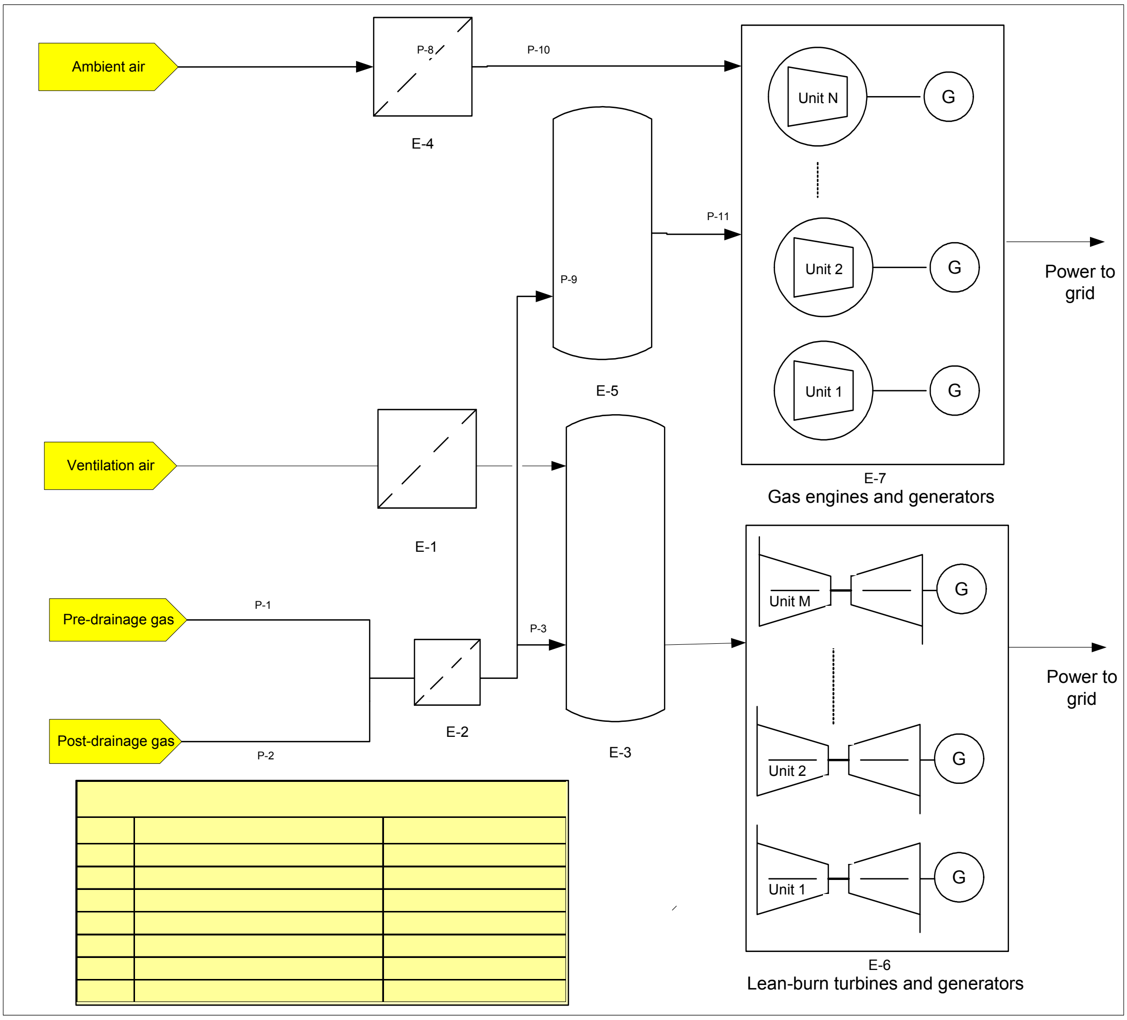


Figure 13 Configuration diagram of the combined lean burn turbine and gas engine power plant system

3.2.4 Technology options

On the basis of the above technical review of ventilation air methane mitigation and utilisation technologies, and available mine site methane emission data, it could be concluded that the following technologies would be considered for this case study, and they will be assessed in terms of preliminary economics later.

- For mitigation of VAM
  - Flow reverse reactors: MEGTEC TFRR and CANMET CFRR
  - Monolithic reactor: CSIRO CMR
- For utilisation of VAM
  - 1.6% CH_4 gas turbine: EDL recuperative gas turbine technology
  - 1% CH_4 gas turbine: CSIRO VAMCAT, Ingersoll-Rand catalytic microturbine. The VAMCAT can be run at a higher methane concentration of up to 1.6%.

It should be pointed out that these technologies are being developed for the mitigation and utilisation of VAM though some technical issues occur for some of the technologies as addressed in Section 3.1. Moreover, in order to have comprehensive and comparable results, conventional gas engine and gas turbine technologies are attempted for utilisation of the drainage gas, however, the gas turbine can not be used for ventilation air because a large part of the air is used for combustion dilution and cooling of the turbine inlet scroll and first stage in the conventional gas turbines resulting in a significant fraction of the methane passing through the turbine without combusting, unless a more complicated gas turbine is developed for this purpose.

It should be pointed out that the ventilation air cleaning is an important issue which could affect the viability of any VAM mitigation and utilisation technology. For example, as discussed above, the 54 one-megawatt Caterpillar G3516 spark-fired engines at Appin Colliery do not take the mine ventilation air anymore due to the ventilation air cleaning cost. However, gas cleaning costs required for each technology are not covered in this case study, and currently CSIRO is studying ventilation air cleaning in a project partly supported by ACARP.

In summary, for all the technologies discussed in Section 3.1 for utilisation of VAM for power generation, if the methane concentration or ventilation air flow rate is variable, it is difficult to extract useful energy as the variations in heat release are likely to cause instability in the system. It will therefore be difficult to maintain stability in the working fluid that recovers the heat at a constant temperature and flow rate. Unfortunately, it is rare for ventilation air from mines to contain even an approximately constant methane concentration, and large fluctuations are common with changing mine operations. The characteristics of mine ventilation air flows including variations of methane concentration and flow rate, and dust loadings etc. can be seen in Ref. [17]. To recover heat for power generation, supplementary fuel is required to bring the CH_4 concentration up to a constant level required by the thermodynamics of a power generation system. Though it has been reported that the TFRR and CFRR technologies have been proposed for VAM power generation, e.g. West Cliff Colliery (WestVAMP) project, which proposes to use drainage gas to increase average methane concentration in the system to 0.9%, we are not able to design any system configuration of power generation with high confidence according to our knowledge and understanding of the flow reverse reactors. Therefore, the flow reverse reactors are only considered for the mitigation purpose in this case study.

In addition, a plant system of combined lean burn gas turbines and conventional gas engines is pursued for maximum utilisation of drainage gas and ventilation air methane with highest efficiency. For this system, the lean burn turbine is used for utilisation of most of VAM, and if necessary part of drainage gas is used to assist the lean burn turbine operation; remaining drainage gas can be used by spark ignition gas engines (the best gas engine technology, developed by GE Jenbacher, promises to use a CH_4 content of 25%) to pursue higher efficiency. Of course, the lean burn turbine can be used for the drainage gas with a methane concentration of less than 25%.

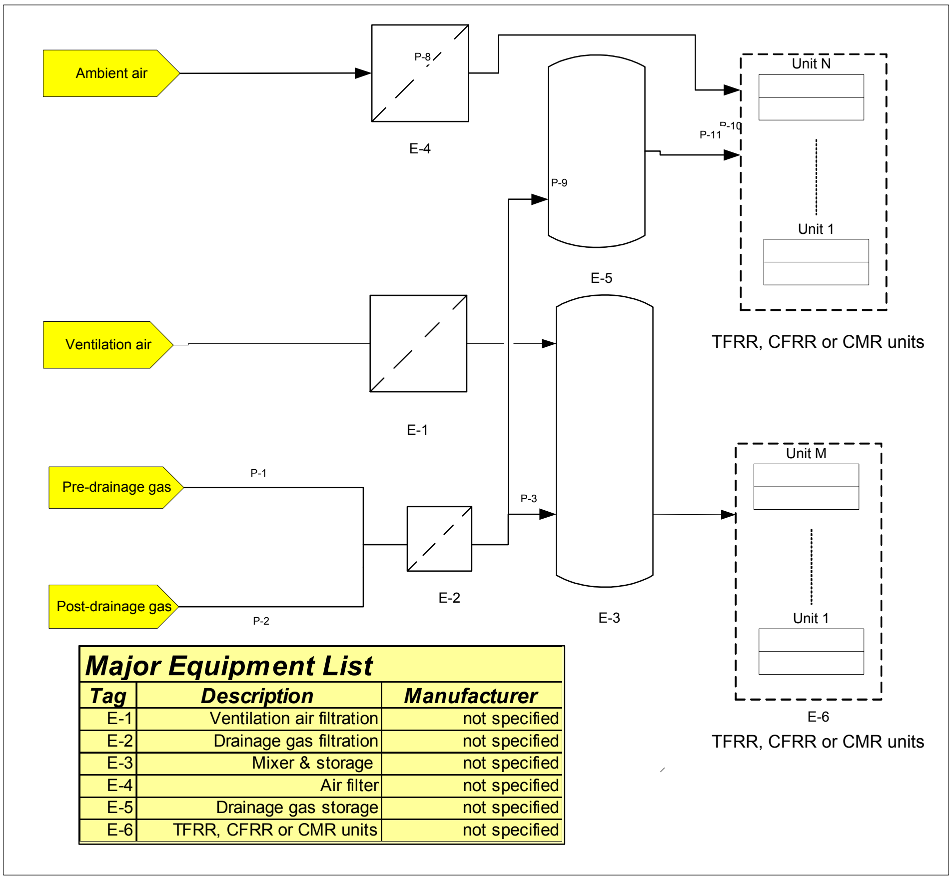
3.2.5 Plant potential, operational status and preliminary economics at Chinese coal mine

3.2.5.1 VAM mitigation

3.2.5.1.1 Plant potential and operational status

As reviewed in Section 3.1, the minimum methane concentrations are 0.2%, 0.1% and 0.3% for TFRR, CFRR and CMR operations, respectively. Based on the data in Figure 8, it is determined that the probabilities of methane concentration being greater than 0.1%, 0.2% and 0.3% are all 100% for the ventilation air; and also the probability of ventilation air flow of greater than $145 m^3/s$ is 97.8%. Therefore, it is evident that from 1 September to 30 November 2004 (91 days) that all of these VAM mitigation technologies, when applied at the Chinese mine, can run with a feed supply availability of over 95%. Hence, for any of the TFRR, CFRR and CMR plants for the VAM mitigation at the Chinese mine, approximately 100% of the ventilation air will be used and 25,374,456 m^3 of methane will be mitigated annually from the ventilation air.

However, at this Chinese mine, the low concentration methane drainage gas can not be used by the abovementioned best gas engines available for power generation due to that the probability of methane concentration being not less than 25% is zero. Therefore, the drainage is also considered for mitigation by the TFRR, CFRR or CMR. It should be pointed out that based on discussions carried out in the past, and information from Ref. [6], possible maximum methane concentration acceptable by TFRR units is 1.2%. This should be applied to CFRR units because the TFRR and CFRR systems differ only with respect to the use of a catalyst. Based on the combustion test results [18], the CMR units can operate at a maximum methane concentration of 1.8%. Therefore, in this case study, operational parameters of TFRR, CFRR and CMR mitigation plants are determined based on the maximum allowable operational methane concentrations. That is, some of the drainage gas is mitigated in the VAM units, and remaining drainage gas is mitigated by more such units using ambient air. Figure 14 is a conceptual design of the TFRR, CFRR or CMR mitigation plant at Chinese mine.



Major Equipment List

Tag	Description	Manufacturer
E-1	Ventilation air filtration	not specified
E-2	Drainage gas filtration	not specified
E-3	Mixer & storage	not specified
E-4	Air filter	not specified
E-5	Drainage gas storage	not specified
E-6	TFRR, CFRR or CMR units	not specified

Figure 14 Configuration diagram of the TFRR, CFRR or CMR methane mitigation plant system at Chinese coal mine

Table 5 summarises the major operating parameters of the 1.2% methane TFRR or CFRR mitigation plant and 1.8% methane CMR mitigation plant, and compares features of the three mitigation technologies in terms of the amount of drainage gas and ventilation air methane mitigated. It is clear that the higher the operational methane concentration of the mitigation units, the less the number of units. This should result in reducing capital cost of the mitigation plant. When the TFRR or CFRR technology is applied, four units are needed for VAM mitigation, and 6.3% of the drainage gas can be mitigated through these four units as well, and 33 units are required for remaining drainage gas mitigation being diluted with about 1,200m^3/s ambient air. Similarly, when the CMR technology is applied, four units are needed for VAM mitigation, and 12.3% of the drainage gas can be mitigated through these four units as well, and 20 units are required for remaining drainage gas mitigation being diluted with about 740m^3/s ambient air. In general, all of the VAM and drainage gas can be mitigated at this Chinese coal mine, which is equivalent to greenhouse gas reduction of 7,607,007 t CO_2-e.

Table 5 TFRR, CFRR, CMR plant potential and major operational parameters at Chinese mine

1 September to 30 November 2004 (91 days)					
Type of VAM mitigation unit		1.2% CH_4 TFRR or CFRR		1.8% CH_4 CMR	
Unit number		4	33	4	20
Working fluid rate per unit, m^3/s		37.5	36.6	37.5	37.0
Working fluid rate, m^3/s		150	1,205	150	740
Total methane mitigated, m^3		14,699,316	123,320,593	22,557,307	115,462,602
From ventilation air	Amount of CH_4, m^3 (out of 6,326,234 m^3)	6,326,234	0	6,326,234	0
	Percentage of total ventilation air methane, %	100	0	100	0
	Ventilation air flow, m^3/s	~145	0	~145	0
From drainage gas	Amount of CH_4, m^3 (out of 131,693,675m^3)	8,373,082	123,320,593	16,231,073	115,462,602
	Percentage of total drainage gas methane, %	6.35	93.65	12.3	87.7
Continuous operational availability, %		99.8	99.7	100	99.8
Total ventilation air mitigated, %		100		100	
Total drainage gas mitigated, %		100		100	
Average per annum with the plant availability of >95%					
Greenhouse gas reduction, t CO_{2-e}		7,607,007		7,607,007	

Figure 15 shows how the TFRR, CFRR or CMR methane mitigation plant could operate at the Chinese mine from 1 September to 30 November 2004. As shown in this figure, for operating the remaining drainage gas mitigation units, the supply rate of ambient air is varied to maintain the methane concentration at 1.2% or 1.8% for the TFRR/CFRR or CMR units respectively. Under such operation, supplied air flow rate can be reduced depending on the remaining drainage gas flow rate to save power consumption. Of course, these units can be operated under another operation protocol that the supplied air flow rate is maintained at the highest flow rate determined based on the highest remaining drainage gas flow rate and maximum operational methane concentration. Then, the operational methane concentration is variable, and not higher than 1.2% or 1.8%, but higher than the minimum required operational methane concentration specified above.

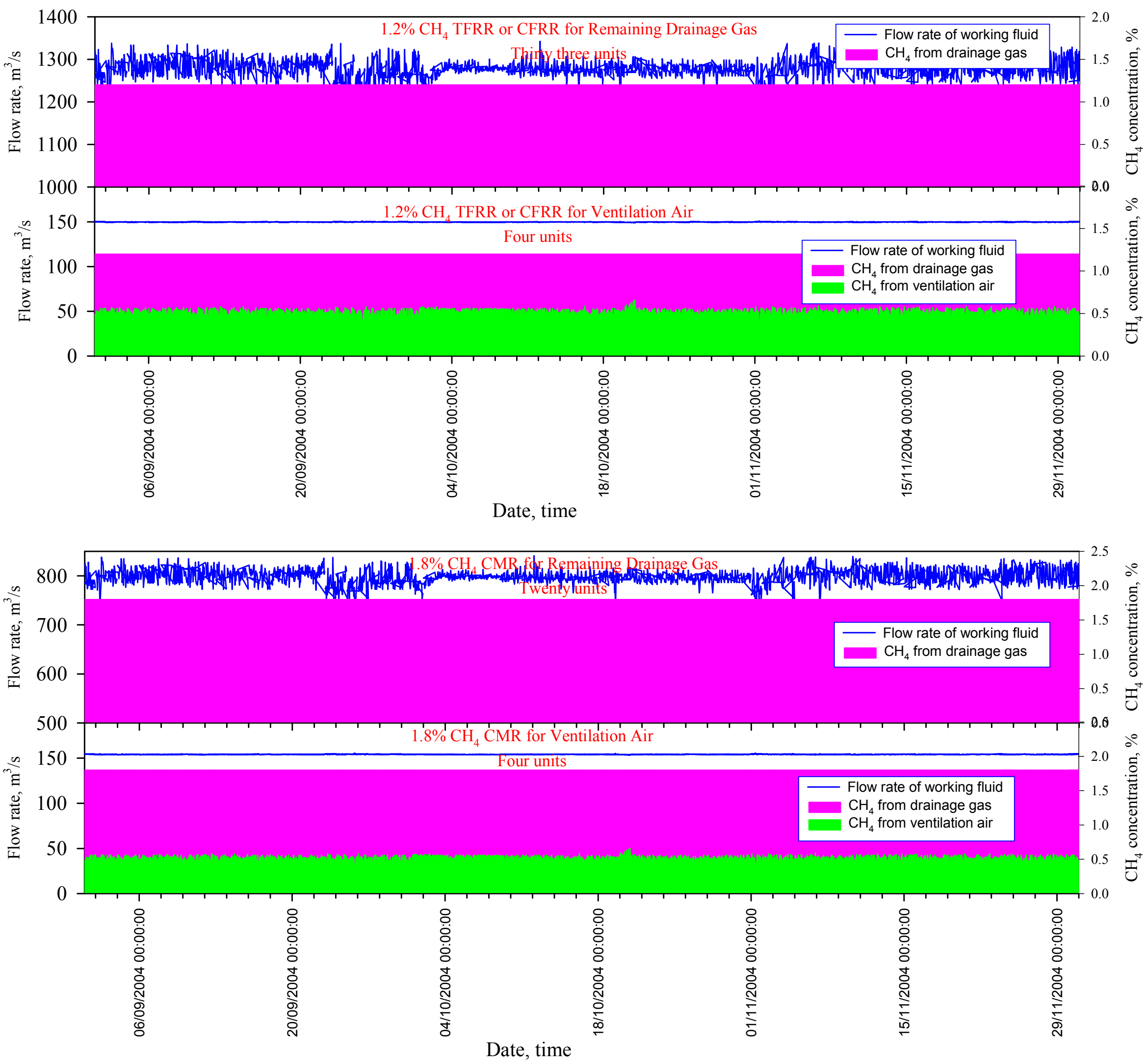


Figure 15 Operational status of TFRR, CFRR or CMR methane mitigation plant at Chinese coal mine

3.2.5.1.2 Preliminary economics

Based on the system diagrams of TFRR, CFRR or CMR methane mitigation plants in and the operating parameters determined previously, a preliminary economic analysis has been performed for the ventilation air methane and drainage gas mitigation plant designs at this Chinese coal mine. The key data for input into the analysis are:

- TFRR plant: 37 TFRR units, and the operating and maintenance costs are estimated to be ¥38,041,380 per year;
- CFRR plant: 37 CFFR units, and the operating and maintenance costs are estimated to be ¥39,628,680 million per year;
- CMR plant: 24 CMR units (including recuperators), and the operating and maintenance costs are estimated to be ¥29,290,780 per year.

Table 6 summarises the major capital costs estimated for the TFRR, CFRR or CMR plants.

Table 6 Estimation of major capital costs of the TFRR, CFRR or CMR plants[d]

TFRR plant		CFRR plant		CMR plant	
Major equipment	Unit price	Major equipment	Unit price	Major equipment	Unit price
TFRR unit [a], $37m^3/s$	37×¥14,200,000	CFRR unit [b], $37m^3/s$	37×¥10,700,000	CMR unit [c], $37m^3/s$	24×¥8,900,000
Fans for ventilation air	4×¥200,000	Fans for ventilation air	4×¥200,000	Fans for ventilation air	4×¥200,000
Ventilation air filtration	4×¥2,070,000	Ventilation air filtration	4×¥2,070,000	Ventilation air filtration	4×¥2,070,000
Fans for drainage gas	2×¥200,000	Fans for drainage gas	2×¥200,000	Fans for drainage gas	2×¥200,000
Pipeline for drainage gas	¥1,180,000	Pipeline for drainage gas	¥1,180,000	Pipeline for drainage gas	¥1,180,000
Drainage gas filtration	2×¥2,070,000	Drainage gas filtration	2×¥2,070,000	Drainage gas filtration	2×¥2,070,000

a. The unit price of TFRR is estimated based on the costs for two commercial demonstration units by CONSOL Energy [19] and proposed WestVAMP project [20].
b. The unit price of CFFR is estimated based on Ref. [21].
c. The unit price of CMR is estimated based on the experimental results of methane catalytic combustion.
d. The major capital costs are determined based on existing information in the USA and Australia, and directly converted into RMB though they could be cheaper by manufacturing in China.

Table 7 summarises the results of this preliminary economic analysis of the TFRR, CFRR and CMR plants at the Chinese mine. The results indicate that the implementation of the methane mitigation plants at this Chinese mine is not economic without a carbon credit. The methane mitigation technology is attractive to investors if the carbon credit is ¥38/t $CO_{2\text{-}e}$, which is the current market price at a Chinese mine. Break-even carbon credits are also determined to ¥12.01, 10.54 and 6.81 /t $CO_{2\text{-}e}$ for the TFRR, CFRR and CMR plants, respectively.

Table 7 Results of the preliminary economic analysis for the TFFR, CFFR and CMR plants

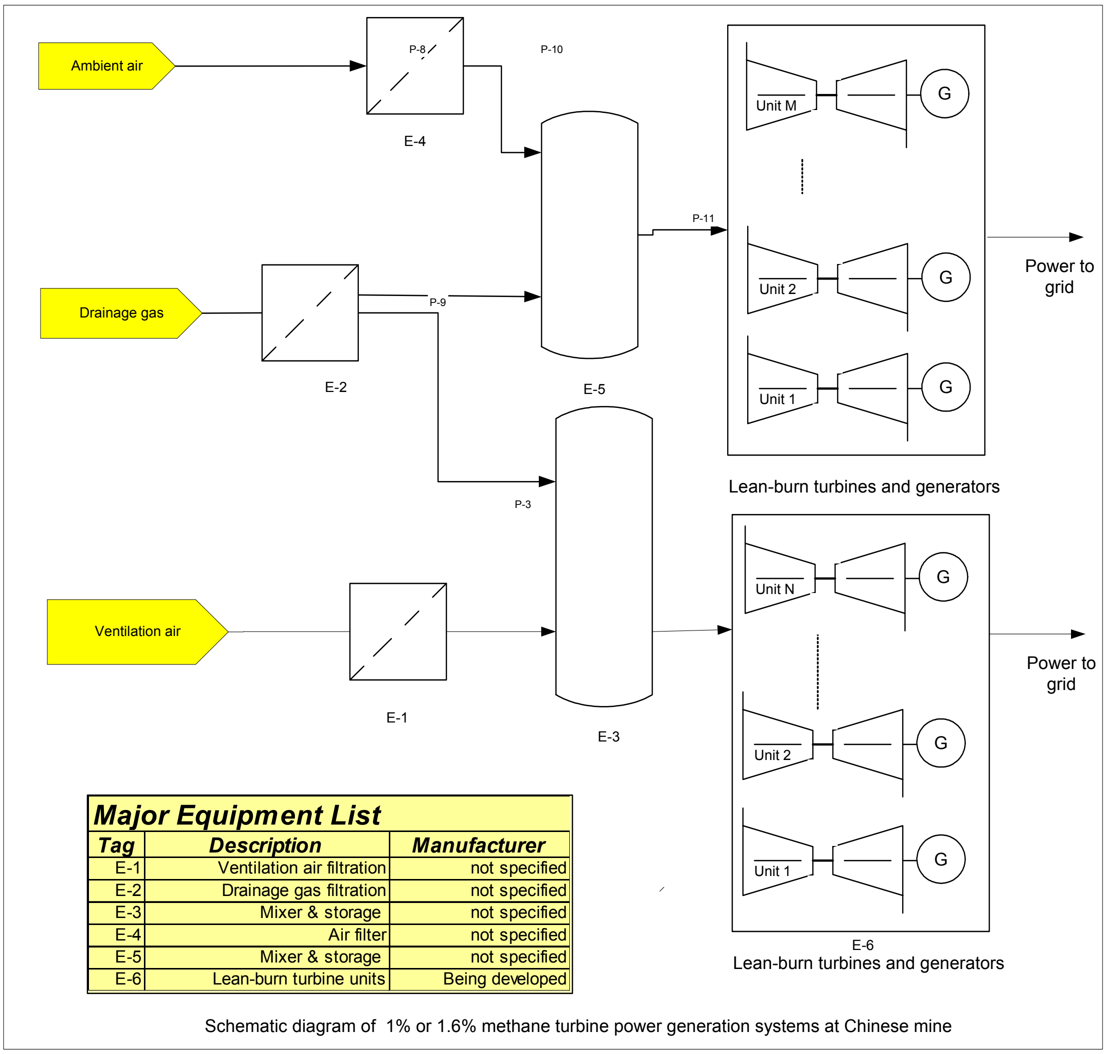
	TFRR plant	CFRR plant	CMR plant
Capital cost, ¥	594,220,000	451,770,000	251,240,000
¥0/t$CO_{2\text{-}e}$			
Net present value, ¥	-1,018,265,203	-893,508,750	-577,742,739
Internal rate of return, %	N/A	N/A	N/A
¥38/t$CO_{2\text{-}e}$			
Net present value, ¥	2,203,940,741	2,328,697,194	2,644,463,205
Internal rate of return, %	42.2	55.2	103.4
Break-even carbon credit[a]			
Break-even carbon credit, ¥/t$CO_{2\text{-}e}$	12.01	10.54	6.81

a. determined based on the discount rate: 7.5%, the internal rate of return: 7.5%, and the net present value: 0.

3.2.5.2 VAM utilisation

3.2.5.2.1 Plant potential and operational status

As reviewed in Section 3.1, the best gas engine technology, developed by GE Jenbacher, promises to use a CH_4 content of 25%. However, based on the mine methane emission data in Section 3.2.1 from 1 September to 30 November 2004 (91 days), the average methane concentration in the drainage gas is 22.1%, and the highest methane concentration is 23%. The probability of methane concentration being not less than 25% is zero. Hence, it would be concluded that the conventional gas engine and gas turbine can not be used for the drainage gas utilisation at this Chinese coal mine, and the combined lean burn gas turbine and conventional gas engine system either. So, only 1% CH_4 or 1.6% CH_4 lean burn gas turbines are considered for the utilisation of both VAM and drainage gas at the Chinese coal mine. Figure 13 is a conceptual design of the 1% or 1.6% methane lean burn turbine power plant at the Chinese mine.



Schematic diagram of 1% or 1.6% methane turbine power generation systems at Chinese mine

Figure 16 Configuration diagram of the lean burn turbine power plant system

Table 8 summarises the major operating parameters of the 1% or 1.6% methane lean burn gas turbine methane utilisation plant assuming the generation efficiency is 20%, and compares their features in terms of amount of drainage gas and ventilation air methane utilised. It is clear that both lean burn turbine plants perform almost equally, and the installable unit number is 40 for both plants. In general, both lean burn turbine plants can utilise 95.8% of the ventilation air methane and about 96% of the drainage gas at this Chinese coal mine, which is equivalent to greenhouse gas reduction of approximately 7 million t CO_2-e, and generate electricity of about 0.26 million MW·hr from 1st September to 30 November 2004 (91 days).

Table 8 Plant potential and major operating parameters at Chinese mine

1 September to 30 November 2004 (91 days)					
Type of power generation unit		1% CH_4 turbine		1.6% CH_4 turbine	
Unit number		4×2.65MW_e	36×3MW_e	6×2.92MW_e	34×2.98MW_e
Working flow rate, m^3/s		~148	1,500	~152	880
Thermal input, MW_t		53.3	540	87.6	506.7
Output, MW_e		10.6	108	17.5	101.4
Electricity generated, MW·hr		23,784	241,056	39,083	226,271
Total methane used, m^3		11,892,096	120,528,000	19,541,606	113,135,616
From ventilation air	Amount of CH_4, m^3 (out of 6,326,234 m^3)	6,062,821	0	6,062,821	0
	Percentage of total ventilation air methane, %	95.8	0	95.8	0
	Ventilation air flow, m^3/s	~145	0	~145	0
From drainage gas	Amount of CH_4, m^3 (out of 131,693,675m^3)	5,829,275	120,528,000	13,478,785	113,135,616
	Percentage of total drainage gas methane, %	4.45	91.5	10.2	85.9
Continuous operational availability, %		97.8 (~100% load)	98.7 (~100% load)	99.6 (~100% load)	98.2 (~100% load)
Total ventilation air usage, %		95.8		95.8	
Total drainage gas usage, %		96.0		96.1	
Total electricity generated, MW·hr		264,840		265,354	
Average per annum with the plant availability of 95%					
Greenhouse gas reduction, t $CO_{2\text{-}e}$		7,298,372		7,312,543	

Figure 17 shows how the 1% or 1.6% lean-burn gas turbine power generation plant operates at the Chinese mine for the mitigation and utilisation of both ventilation air methane and drainage gas.

3.2.5.2.2 Preliminary economics

Based on the system diagram of the 1% or 1.6% methane gas turbine plants shown in Figure 16 and the operating parameters in Table 8, a preliminary economic analysis was conducted to determine the economic feasibility of the application of the 1 and 1.6% methane turbine plants into Chinese coal mine. It was summarised as follows:

- 1% methane power plant: forty 2.65~3MW_e units are installed, and the operating and maintenance costs are estimated to be ¥56,927,060 per year.
- 1.6% methane power plant: forty 2.92~2.98MW_e units, and the operating and maintenance costs are estimated to be ¥51,782,580 per year.

Table 9 summarises the major capital costs estimated for the 1 and 1.6% methane turbine plants.

Table 10 summarises the results of the preliminary economic analysis of the 1 and 1.6% methane turbine power plants at the Chinese mine under different conditions. The results indicate that the applications of the 1% and 1.6% methane turbine plants at the mine are economically feasible. As to the basic case with no carbon credit, the break-even costs of generating electricity are ¥119.42 and ¥116.25/MWh for the 1% and 1.6% methane turbine plants, respectively; and the internal rates of return are 48.9 and 48.1. In summary, there is no significant difference between the two turbine plants in terms of their performance at this Chinese coal mine mainly because the low methane concentration drainage gas can not be used by the conventional gas engines with high efficiency. If the drainage system is improved to the methane concentration of no less than 25%, the scenario of power plant system configuration should be different at this Chinese coal mine, i.e. the combined lean burn turbine and gas engine system, shown in Figure 13, can be applied.

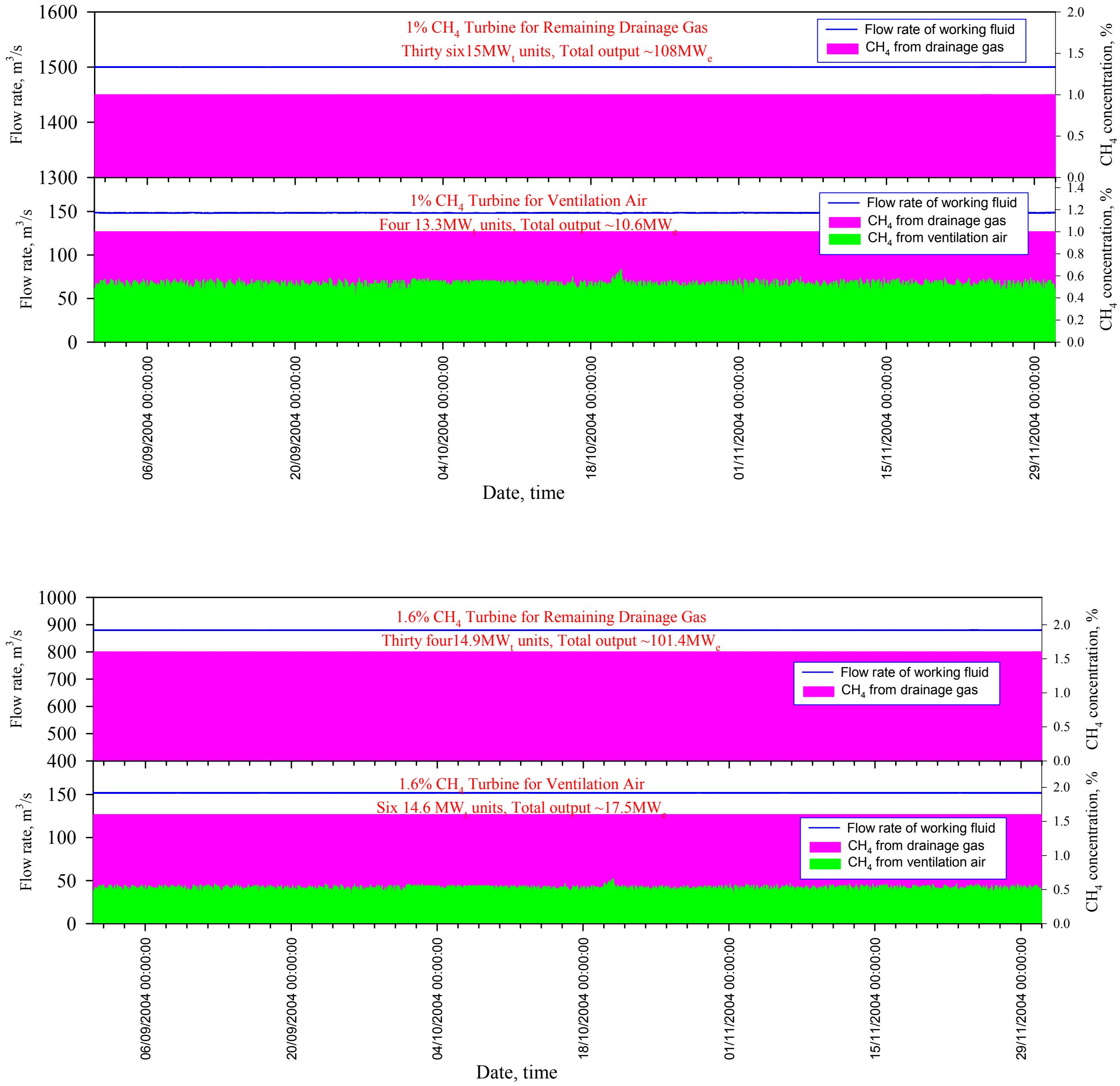


Figure 17 Operating status of the 1% methane turbine plant at the Chinese mine

Table 9 Major capital costs of the 1 and 1.6% CH_4 turbine power plant [b]

1% CH_4 power plant		1.6% CH_4 power plant	
Major equipment	Unit price	Major equipment	Unit price
1% CH_4 catalytic turbine unit [a], 2,650~3,000kW	40×¥15,442,000	1.6% CH_4 catalytic turbine unit [a], 2,920~2,980kW	40×¥16,082,000
Fans for ventilation air	4×¥200,000	Fans for ventilation air	6×¥130,000
Ventilation air filtration	4×¥2,070,000	Ventilation air filtration	6×¥1,380,000
Fan for drainage gas	2×¥200,000	Fan for drainage gas	2×¥200,000
Filter/scrubber for drainage gas	2×¥2,070,000	Filter/scrubber for drainage gas	2×¥2,070,000
Pipeline for drainage gas	¥1,180,000	Pipeline for drainage gas	¥1,180,000
Mixer/storage	40×¥296,000	Mixer/storage	40×¥207,000

a. the unit prices of the lean-burn turbines are "best" estimates based on current market price of same-size conventional gas turbines.
b. the major capital costs are determined based on existing information in USA and Australia, and directly converted into RMB though they could be cheaper by manufacturing in China.

Table 10 Results of the preliminary economic analysis for the 1 and 1.6% methane turbine power plant

	1% CH_4 plant	1.6% CH_4 plant
Plant size, MW_e	118.6	118.8
Capital cost, ¥	708,752,000	732,974,000
Capital cost, ¥/kW_e	5,976	6,169
¥0/tCO_{2-e}		
Net present value, ¥	3,156,291,689	3,198,147,740
Internal rate of return, %	48.9	48.1
Break-even cost of electricity, ¥/MWh	119.42	116.25
¥38/tCO_{2-e}		
Net present value, ¥	6,247,764,676	6,295,623,579
Internal rate of return, %	88.1	86.0
Break-even cost of electricity, ¥/MWh	- 155.41	-158.58

3.3 APPLICATIONS OF CMM/VAM TECHNOLOGIES AT TWO AUSTRALIAN COAL MINES

In the following sections, some results of previous case studies, carried out for two Australian mines, are given to compare performance of a range of methane mitigation and utilisation technologies when the methane concentration of drainage gas meets the minimum requirements by conventional gas engine and gas turbine. And also, the combined lean burn turbine and conventional gas engine system can be applied to maximally utilise both VAM and drainage gas with the highest efficiency and output.

3.3.1 Queensland coal mine

3.3.1.1 Methane emissions

Figure 18 shows the characteristics of methane emissions from a Queensland mine (QLD, Australia). As shown in this figure, based on the average values in 2002, the characteristics of methane emissions can be summarised in the following statements.

- Methane emissions: 32,433,515m^3/year from the ventilation air, 66,475,933m^3/year from the drainage gas.
- Percent of methane emitted from the ventilation air is 32.8%.
- Average methane concentration in ventilation air: 0.56%.
- Average methane concentration in pre-drainage gas: 79.2%, and 71.8% for post-drainage gas.
- Average pure methane flow rate of the drainage gas: 2.11m^3/s.

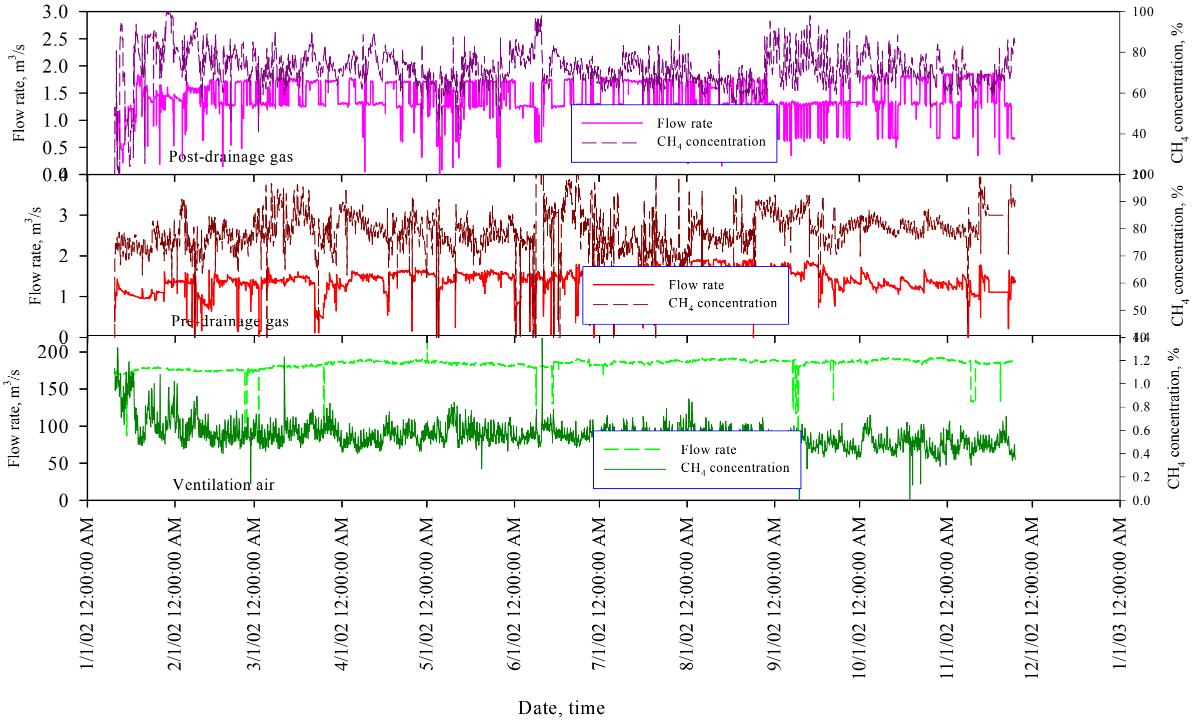


Figure 18 Characteristics of methane emissions from a Queensland mine

*3.3.1.2 **Plant potential***

Based on the data collected at the QLD mine from 10 January to 24 November 2002 (319 days), it was determined that 4×3 MW$_e$ 1% methane turbine units and 14×1 MW$_e$ spark-ignition gas engine units can be installed at the QLD mine. Table 11 summarises the major operating parameters of the 1% methane turbine and gas engine power plant, and also compares features of the two power generation technologies in terms of usage of drainage gas and ventilation air methane, and power output, and annual greenhouse gas reduction calculation for QLD mine. Figure 19 compares the plant sizes and throughput for the power plants. The gas engine power plant has the same generation capacity, 26 MW$_e$, as the combined 1% methane turbine and gas engine power plant, however, the combined 1% methane turbine and engine power plant has a slightly higher production of electricity during the 319 days. This is because the gas engine plant runs at lower load longer than the combined 1% methane turbine and engine plant.

Table 11 Plant potential and major operating parameters at QLD mine

10 January to 24 November 2002 (319 days)			
		Combined 1% CH_4 turbine and engine plant	
Type of power generation unit		1% CH_4 turbine	Gas engine
Unit number		4×3MW_e	14×1MW_e
Thermal input, MW_t		61	38.7 (average)
Output, MW_e		12	13 (average)
Electricity generated, MW·hr		93,514	99,402
Total methane used, m^3		46,762,920	29,588,962
From ventilation air	Amount of CH_4, m^3 (out of 28,200,149 m^3)	25,953,753	0
From drainage gas	Amount of CH_4, m^3 (out of 58,018,603 m^3)	20,809,167	29,588,962
Greenhouse gas reduction, t $CO_{2\text{-}e}$		676,392	427,983
Total ventilation air usage, %		92	
Total drainage gas usage, %		86.9	
Total electricity generated, MW·hr		192,916	
Average per annum with the plant availability of 95%			
Total greenhouse gas reduction, t $CO_{2\text{-}e}$		1,200,446	

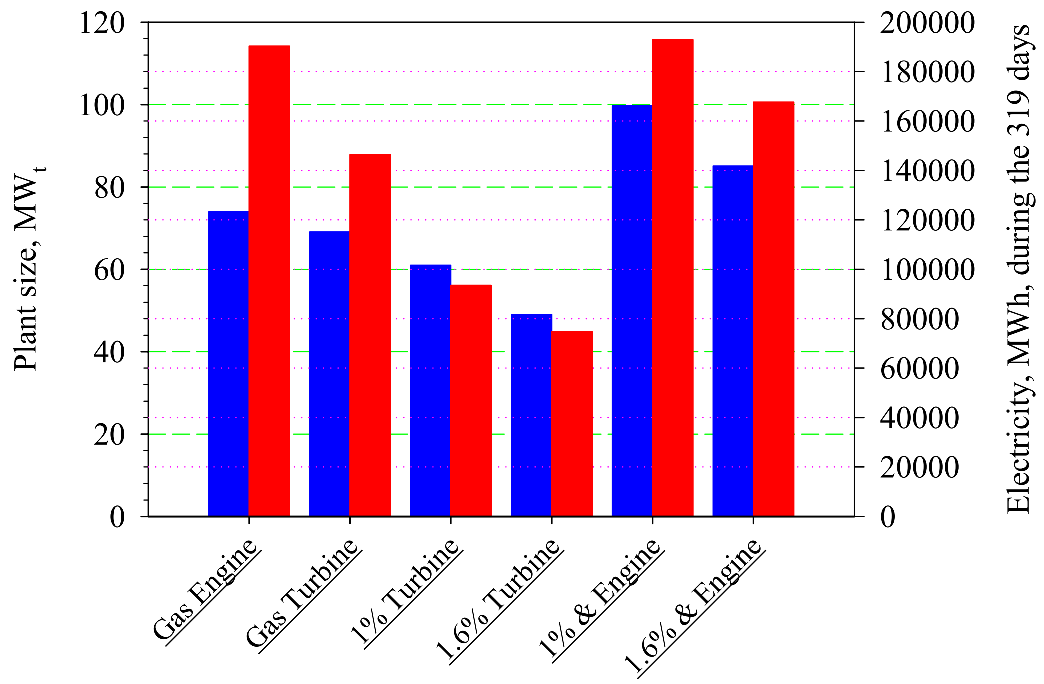


Figure 19 Comparison of plant sizes and electricity production

3.3.2 New South Wales coal mine

3.3.2.1 Methane emissions

Figure 20 shows the characteristics of methane emissions from the NSW mine. The data on the ventilation air flow, manually recorded, are presented as they are much more accurate than the data retrieved from the mine data system. Generally, ventilation air flow is maintained to be constant for any mine. These ventilation air flow data were used for further data processing. It should be noted that the post-drainage gas goes into the pre-drainage gas pipeline to the gas drainage plant. Also, it can be seen from Figure 20 that the information on the drainage gas was not correctly recorded in the mine data system from 2 August to 24 November 2002. Therefore, the methane emission data from 3 May to 1 August 2002, and from 25 November 2002 to 23 January 2003 (total 151 days) was used for the assessment of the plant potential. According to the data collected at the mine, based on the average values during the 151 days, the characteristics of CH_4 emissions at the NSW mine are summarised as follows:

- Methane emissions: 84,138,048m^3/year from the ventilation air, 46,870,380m^3/year from the drainage gas.
- Percent of methane emitted from the ventilation air is 64.2%.
- Average methane concentration in ventilation air: 0.92%.
- Average methane concentration in drainage gas: 49.7%.
- Average pure methane flow rate of the drainage gas: 1.47m^3/s.

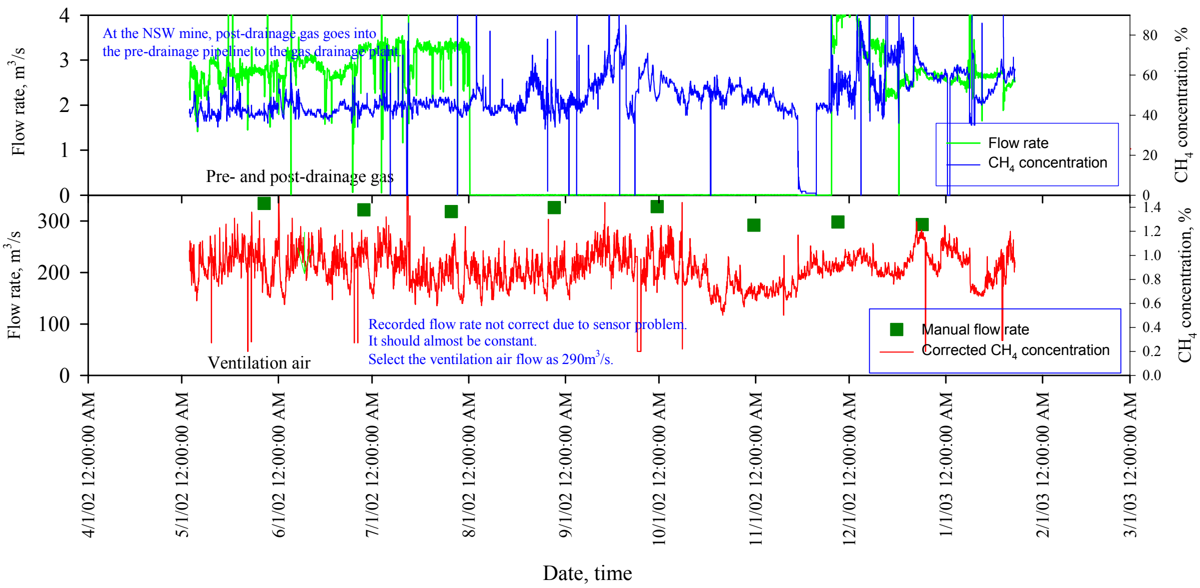


Figure 20 Characteristics of methane emissions from the NSW coal mine

3.3.2.2 Plant potential

Based on the data collected at the NSW mine from 3 May to 1 August 2002, and from 25 November 2002 to 23 January 2003 (total 151 days), it was determined that 7×3 MW$_e$ 1% methane turbine units and 6×1 MW$_e$ spark-ignition gas engines can be installed at the NSW mine. Table 11 summarises the major operating parameters of the 1% methane turbine and gas engine power plant, and also compares features of the two power generation technologies in terms of usage of drainage gas and ventilation air methane, and power output, and annual greenhouse gas reduction calculation for the NSW mine. As shown in Figure 21, the 1% methane turbine plant, or in the combination of gas engine units, performs much better at this typical NSW gassy coal mine than at the QLD mine in terms of the plant size (thermal input) and the electricity production.

Table 12 Plant potential and major operating parameters at NSW mine

3 May to 1 August 2002, and from 25 November 2002 to 23 January 2003 (151 days)			
		Combined 1% CH_4 turbine and gas engine plant	
Type of power generation unit		1% CH_4 turbine	Gas engine
Unit number		7×3MW_e	6×1MW_e
Thermal input, MW_t		121.1	
Output, MW_e		26.5 (average)	
Electricity generated, MW·hr		93,618	
From ventilation air	Amount of CH_4, m^3 (out of 34,211,462 m^3)	33,550,746	
From drainage gas	Amount of CH_4, m^3 (out of 18,250,124m^3)	9,664,773	
Greenhouse gas reduction, t CO_{2-e}		625,082	
Total ventilation air usage, %		98.1	
Total drainage gas usage, %		53	
Average per annum with the plant availability of 95%			
Greenhouse gas reduction, t CO_{2-e}		1,435,411	

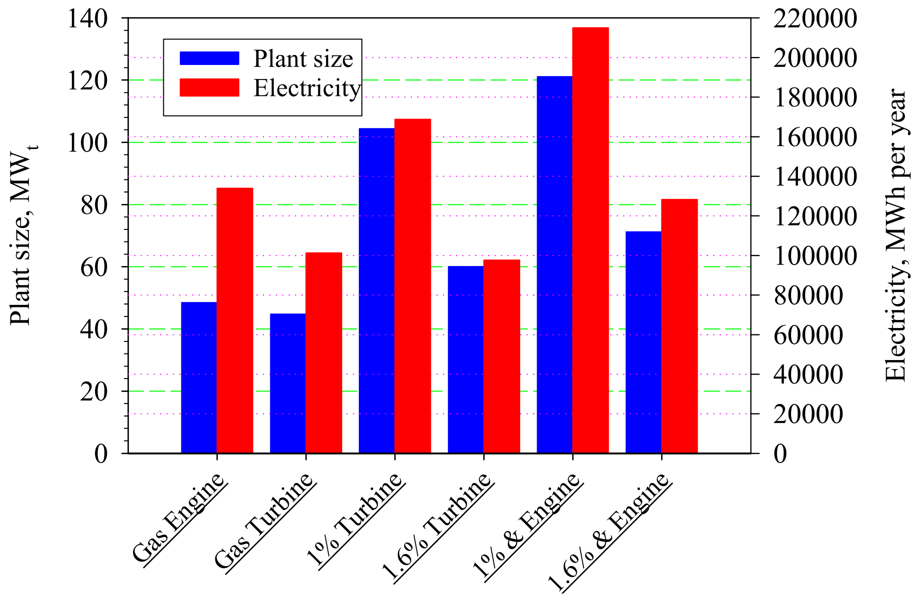


Figure 21 A comparison of plant sizes and electricity production at the NSW mine

3.4 CONCLUSIONS FOR CASE STUDY B

For Case Study B, existing and developing VAM mitigation and utilisation technologies have been reviewed, and then an assessment of implementation of these technologies into a Chinese coal mine was carried out to identify best options for the mine by conducting the system configuration and conceptual plant designs and determination of plant potential and operating status, and evaluation of preliminary economic benefit based on the mine methane emissions from this coal mine. The following conclusions would be made.

- No technology has been successfully demonstrated at a mine site for the utilisation of VAM.
- No single technology solution could be applied to the treatment of methane in mine ventilation air, as circumstances at mines are dependent on local conditions. A range of technology options could be necessary that would be mixed and matched for the best results at any particular site.
- TFRR, CFRR and CMR would be technically feasible for the VAM mitigation depending minimum CH_4 concentration of ventilation air, but not economic without the carbon credit.
- The 1% CH_4 lean burn turbine would be the best option proposed so far for the utilisation of VAM.
- The combined lean burn turbine and gas engine system promises to maximally use both drainage gas and VAM with highest efficiency and output for a number of mines.
- Care should be taken for ventilation air cleaning etc.
- For this Case Study, the scenario would be different if the drainage gas quality can be improved to the CH_4 concentration of ≥25%. In other words, the combined lean burn turbine and gas engine power plant system would be chosen to achieve the maximum utilisation of drainage gas and VAM with highest efficiency and output.

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