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An assessment of mine methane mitigation and utilisation technologies

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Abstract

Fugitive methane, emitted from coalmines around the world, represents approximately 8% of the world's anthropogenic methane emissions that constitute a 17% contribution to total anthropogenic greenhouse gas emissions. Coal mine methane is a general description for all methane released prior to, during and after mining operations. As such, there is considerable variability in flow rate and composition of the various gas emissions during mining operations. At a typical gassy mine methane is emitted in three streams: (1) mine ventilation air (0.1–1% CH_4), (2) gas drained from the seam before mining (60–95% CH_4), and (3) gas drained from worked areas of the mine, e.g. goafs, (30–95% CH_4). Ventilation air methane contributes approximately 64% of coalmine methane emissions from typical gassy coal mines.

The existing and developing technologies for coal mine methane mitigation and utilisation are classified, with a discussion of the features of different technologies to identify potential technical issues for each technology when implemented at a mine site and to identify the best options for mine site applications. A technical assessment of these technologies for use at a Queensland coal mine is presented, with a preliminary economic assessment of some technologies that were determined to be technically feasible. The assessment is carried out on the basis of real mine methane emission data over about a 1-year time frame.

Keywords: Coal mine methane; Greenhouse gas; Mitigation; Utilisation; Waste energy; Power generation

Contents

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1. Introduction

Fugitive methane, emitted from coalmines around the world, represents approximately 8% of the world's anthropogenic methane emissions that constitute a 17% contribution to total anthropogenic greenhouse gas emissions [1]. Coal mine methane is a general description for all methane released prior to, during and after mining operations. As such, there is considerable variability in flow rate and composition of the various gas emissions during mining operations. At a typical gassy mine, methane is emitted in three streams: (1) mine ventilation air (0.1–1% CH_4), (2) gas drained from the seam before mining (60–95% CH_4), and (3) gas drained from worked areas of the mine, e.g. goafs (30–95% CH_4). Ventilation air methane contributes approximately 64% of coalmine methane emissions mostly from gassy coal mines.

Drainage gas with over 30% methane concentration can be utilised in a number of industrial production processes, such as gas turbines to generate power as long as there is no problem with supply continuity. It is feasible to set up a stable flame when the heating value of the drainage gas is approximately 10 MJ/m^3 at about 30% methane. For example, internal combustion engines, such as compression-fired diesel engines and compression ignition engines modified to be spark-fired engines, commonly use medium-quality gas to generate electricity [2]. In Australia, 54 one-megawatt Caterpillar G3516 spark-fired engines are installed at the Appin Colliery, which use drainage gas (mixture of pre- and post-drainage gases). In the USA, 27% of coal mine methane from underground coal mines is drained and used, and most of this methane is captured and utilised as natural gas pipeline sales [3]. Recently, electricity generation has also been the target product by using coal mine methane in the USA [3]. A recent methane purification study in Australia [4] indicated that purification of the methane to a concentration suitable for sale as pipeline quality gas or liquefied natural gas appears to be a higher value application assuming an industrial consumer is located near the mine.

Ventilation air methane is the most difficult source of methane to use as an energy source, as the air volume is large and the methane resource is dilute and variable in concentration and flow rate. The low concentration of methane in mine ventilation air is a major problem, and mitigation requires either treatment in its dilute state, or concentrating 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 developed, and most work has focussed on the oxidation of very low concentration methane. These processes may be classified into thermal oxidation and catalytic oxidation in terms of combustion kinetic mechanisms. Utilisation technologies of ventilation air methane generally are divided into two basic categories: ancillary uses and principal uses. For the ancillary uses, ventilation air is used to substitute ambient air in combustion processes, including gas turbines, internal combustion engines and coal-fired power stations.

For the principal uses, methane in ventilation air is a primary fuel. These processes include MEGTEC thermal flow-reversal reactors (TFRR). CANMET catalytic flow-reversal reactors (CFRR), EDL recuperative gas turbine, CSIRO lean burn catalytic turbine, and CSIRO catalytic combustor (CMR) that could be combined with coal drying, or heating/cooling with an adsorption chiller. The main problem with TFRR and CFRR systems is that it is difficult to extract useful energy for power generation and most installations only reduce the greenhouse impact of the methane by combusting it without extraction of energy. The turbine technologies can both mitigate the methane and generate electricity. The required methane concentration (1% for the CSIRO system and 1.6% for the EDL system) can be obtained by combining mine ventilation air methane and drainage gas at a gassy mine. In addition, a concentrator could be used to enrich methane in mine ventilation air to levels that meet the requirements of lean-burn methane utilisation technologies. If the methane can be concentrated to approximately 30% or higher, conventional gas turbines can be employed to generate electricity without significant modification. A successfully demonstrated unit (concentrator) would make a breakthrough in the development of mine ventilation air methane utilisation technologies.

This paper classifies existing and developing technologies for coal mine methane mitigation and utilisation, and then compares and discusses features of different technologies to identify potential technical issues for each technology when it is implemented into a mine site and to identify best options for mine site applications. Detailed results of a technical assessment of these technologies for a Queensland coal mine are presented, and an economic assessment of some technologies previously determined to be technically feasible. The technical and economic assessment is carried out on the basis of real mine methane emission data over about a 1-year time frame. Note that all costs in this analysis are for application in Australia and the currency units are Australian dollars.

2. Technology classification

A general classification process for coal mine CH_4 mitigation and utilisation technologies is illustrated in Fig. 1 so that one could easily have an overview of all possible mine methane mitigation and utilisation technologies in relation to mine methane emission streams. Table 1 details classification of drainage gas mitigation and utilisation technologies. Mitigation and Utilisation technologies of ventilation air methane generally can be divided into two basic categories: ancillary uses and principal uses. Table 2 details classification of ventilation air methane mitigation and utilisation technologies so that one could easily understand differences of the technologies in terms of fundamental mechanisms, technical principles and applicability.

3. Progress in developing technologies for drainage gas

Potential options for utilisation of methane from coal mine pre- and post-drainage gas have been summarised by the US EPA [5]. These options include:

- Use of coal mine methane in blast furnaces,
- Coal mine methane use in brine water treatment,
- Co-firing coal mine methane in coal-fired utility and industrial boilers,
- Using coal mine methane in cogeneration power systems,
- Enrichment of medium quality coal mine gas,
- Coal mine methane use in fuel cells,
- Use of coal mine methane in greenhouses,

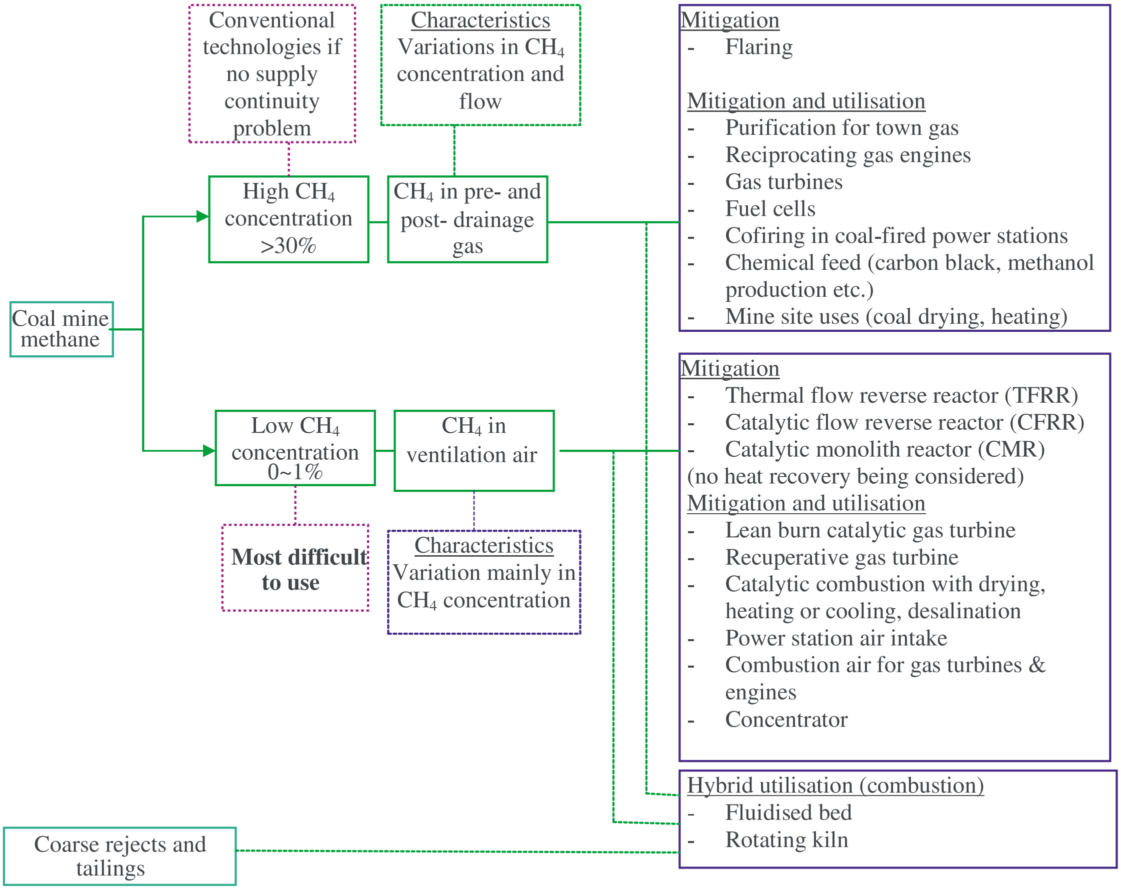


Fig. 1. Illustration of classifying mine methane mitigation and utilisation technologies.

Table 1
Drainage gas technology classification

Technology	Mechanism	Principle	Application status
Purification			
Purification for town gas	Separation	Gas purification process	Demonstrated in full-scale units providing pipeline gas
Power generation/cogeneration			
Reciprocating gas engine	Combustion	Combustion in engine combustor	Mitigation Utilisation—demonstrated
Conventional gas turbine	Combustion	Combustion in conventional gas turbine/engine combustor	Mitigation Utilisation—demonstrated
Co-firing in power stations	Combustion	Combustion inside boilers	Mitigation Utilisation—demonstrated
Fuel cell power generation	Electrochemical reaction	Electrochemical process	Mitigation Utilisation—being proposed as a concept
Chemical feedstocks			
Chemical feedstocks: methanol and carbon black	Synthetic	Synthetic processes	Mitigation Utilisation—being tested in a pilot-scale unit

Table 2
Ventilation air methane technology classification

Technology	Oxidation mechanism	Principle	Application status
Ancillary uses			
Combustion air for conventional pf power station	Thermal	Combustion in of 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	Thermal	Combustion in conventional gas turbine combustor	Mitigation Utilisation—studied
Combustion air for gas engine	Thermal	Combustion in gas engine combustor	Mitigation Utilisation—demonstrated
Hybrid waste coal/tailing/methane combustion in a kiln	Thermal	Combustion inside a rotating combustion chamber	Mitigation Utilisation—being preliminarily trialled in a pilot-scale unit
Hybrid waste coal/tailing/methane combustion in a fluidised bed	Thermal	Combustion inside a fluidised bed and freeboard	Mitigation Utilisation—being proposed as a concept
Principle uses			
Thermal flow reverse reactor (TFRR)	Thermal	Flow reverse reactor with regenerative bed	Mitigation—demonstrated Utilisation—planned by BHP Billiton
Catalytic flow reverse reactor (CFRR)	Catalytic	Flow reverse reactor with regenerative bed	Mitigation—demonstrated Utilisation—not demonstrated yet
Catalytic monolith combustor (CMR)	Catalytic	Monolith reactor with a recuperator	Mitigation—demonstrated Utilisation—not demonstrated yet
Catalytic lean burn gas turbine	Catalytic	Gas turbine with a catalytic combustor and a recuperator	Mitigation—combustion demonstrated Utilisation—being developed in a lab-scale unit
Recuperative gas turbine	Thermal	Gas turbine with a recuperative combustor and a recuperator	Mitigation—demonstrated Utilisation—demonstrated in a pilot-scale unit, and need for further modifications (?)
Concentrator	N/A, adsorption	Multi-stage fluidised/moving bed using adsorbent, and a desorber	Mitigation Utilisation—under development

– Use of coal mine methane in internal combustion engines at coal mines,
– Coal mine methane to liquefied natural gas (LNG),
– Generating electricity with coal mine methane-fuelled turbines,
– Using coal mine methane for heating mine facilities,
– Coal mine methane use in methanol production,
– Conversion of coal mine methane into synthetic fuels,
– Use of coal mine methane in coal dryers, and
– Using coal mine methane to heat mine ventilation air.

Based on the principle/mechanism for end-use of coal mine methane, most of these technical options can be categorised into: (1) methane oxidation (combustion), and (2) chemical feedstocks. Also, according to application purposes these technical options can be divided into three categories: (1) purification for town gas (pipeline gas), (2) power generation, and (3) chemical feedstocks. Some of the options are limited in application due to mine site locations, e.g. use of coal mine methane in blast furnaces and in greenhouses. Most of the potential technologies are discussed in detail below.

3.1. Purification for town gas

Gas drained from coal mines typically contains 30–90% methane. Although coal mine methane is a potentially valuable fuel source, many mines vent it to the atmosphere, particularly post-drainage gas [5]. Also some mines flare coal mine methane both from pre- and post-drainage gas, resulting in a significant waste of energy. In most countries, a minimum of 95% methane is required to meet the quality specifications for natural gas pipeline sales [5,15]. Enrichment facilities have been successfully upgrading medium-quality gas from natural gas wells to pipeline specifications and a cryogenic enrichment plant has been commercially demonstrated with coal mine methane, but it is generally not economically possible to remove nitrogen, oxygen, carbon dioxide, and water vapour in an integrated system [5]. There are four basic processes that are commonly used for gas purification activities, namely solvent adsorption, pressure swing adsorption, cryogenic separation and membrane separation. Brief introductions of each of these processes, as applied to methane purification, are given below [4,6].

3.1.1. Solvent adsorption

Solvent adsorption is sometimes referred to as Selective Absorption. This process uses specific solvents that have different absorption capacities with respect to different gas species. The petroleum refining industry commonly uses this method to enrich gas streams [6]. It is also very common in the natural gas processing industry, and a variation called the Benfield process is often used [7]. This process utilises a solvent containing di-ethylamine (DEA) and potassium carbonate (K_2CO_3) to remove the surplus carbon dioxide from the raw natural gas. A number of other solvents are used in different processes based on the same principles, with numerous proprietary mixtures having been developed. Common solvents for these processes include mono-ethanolamine (MEA), di-ethanolamine (DEA), methyl-di-ethanolamine (MDEA) and di-ethylene glycol (DEG), either individually or in combination. Each of these solvents and combinations has different properties in the quantity of gas it can adsorb and the operating conditions that are optimal to performance. The development of new solvents continues, as it is beneficial to the process economics to reduce the quantity required and the amount lost due to thermal degradation [4].

Unfortunately, this type of process is not suitable for nitrogen removal from gas, as it is not readily soluble in the solvents, so it is not practical to use the process where air contamination of the gas is likely to result in nitrogen concentrations over 5%. As most mine drainage gas has significant levels of air contamination, or cannot be guaranteed to not have periodic contamination, the solvent adsorption process was rejected as being generally unsuitable for drainage gas purification. In many cases, if the drainage gas from a mine is free of air contamination there will be no need to purify it beyond simple scrubbing or filtration as the carbon dioxide content is typically below pipeline specification [4].

3.1.2. Pressure swing adsorption

The principles of operation of the pressure swing adsorption (PSA) process are essentially the same as for a solvent adsorption process [7,8]. The key difference is that, in the case of PSA, the adsorbent is a solid and cannot easily be made to flow away from the adsorption vessel to a regeneration vessel. Therefore, it is common practice that the PSA unit be stopped periodically to allow regeneration of the adsorbent in the vessel. This means that the PSA process is operated on a semi-batch basis with several parallel process trains to allow continuous operation. In general, during successive cycles, the process preferentially adsorbs nitrogen in favour of methane until the output attains the desired methane proportion [5].

PSA plants are in common usage in many different gas-processing applications, however they are typically utilised for small to medium size applications, as it is difficult to build large adsorbent vessels that operate correctly. The nature of adsorption is such that flow of gas through the vessels is required to be plug flow and this is difficult to achieve with large diameter vessels, while long vessels result in large pressure drop. There are a number of different suppliers of adsorbents for use in methane purification, with the adsorbent usually being provided in the form of pellets such as wide-pore carbon molecular sieves. The different products provide different levels of effectiveness in removing different impurities, so data for a real adsorbent must be used in any design calculations. The different performance characteristics arise from the different chemical composition of the materials and the size of the pores into which gases must migrate to be adsorbed. Examples of the available adsorbents are the Molecular Gate adsorbents developed by Engelhard [8]. Two forms of absorbent are available, one for carbon dioxide removal and the other for nitrogen removal. The nitrogen removal adsorbent will also remove carbon dioxide and oxygen, so is well suited to the application of purifying drainage gas. Prior to the development of this type of adsorbent it is likely that the purification process would have required two or more different adsorbents utilised in vessels in series to remove different contaminants.

3.1.3. Cryogenic separation

A cryogenic process involves a sequence of compression, flash vaporisation and heat exchange stages to cool the gas stream until it liquefies, then uses a distillation separator to, in this case, separate a nitrogen-rich gas stream from leave a methane-rich liquid stream [5]. Technically, the cryogenic separation involves cooling the gas mixture to the point when some portion of the gas liquefies at the applied pressure. While this liquid will typically be a mixture of components, the concentrations will be different in the gas phase with the higher boiling point components being in higher concentrations. The boiling points of the two key components are -161.5 °C for methane and -196.0 °C for nitrogen at atmospheric pressure, so a high purity liquid methane product is possible from the separation [7,9]. The other significant components in the gas are oxygen, water vapour and carbon dioxide. Most manufacturers regard the compression to high pressure to be dangerous when oxygen is present and, therefore, it is catalytically converted to carbon dioxide prior to the second stage of compression. Water vapour should also be removed prior to compression to avoid condensation and icing as the gas is cooled. Carbon dioxide has a much higher freezing point than the other gases and conventionally it is removed by amine scrubbing to prevent blockages when it solidifies in the pipework. However, modern small-scale cryogenic plants use oversized equipment in the early cooling sections so that carbon dioxide slush can be formed and removed without blockage of piping [10].

Table 3
Basic characteristics and differences of the purification technologies [5,6]

Technology	Solvent adsorption	Pressure swing adsorption	Cryogenic separation	Membrane separation
Sorbent	Liquid	Solid	n/a	n/a
Phase change	No	No	Yes	No
First stage deoxygenation	Yes	No	Yes	
Methane recovery	96–98%	Up to 95%	98%	
Technical issues for application	Unsuitable for nitrogen removal	Small to medium size		Scaling-up problem

Due to the low temperatures required in the plant, three refrigerants are used to cool the gas, namely propane, ethylene and methane. These are liquefied in the plant by compressing and then expanding the gas to use the Joule–Thompson Effect to create a cold refrigerant stream. In order to cool the lower boiling point refrigerants to a temperature where they can be liquefied, they must first be cooled by the other refrigerants. This results in a complex multi-loop process with the refrigerants passing through multi-stream LNG heat exchangers before being recompressed and cooled for reuse.

3.1.4. Membrane separation

Membrane technology is a rapid growth area and development of specialised membranes for the separation of different gases has progressed significantly in recent years. However, there has been some resistance by industry to adopt membrane plants on a large scale due to the unproven long-term performance of the membranes and the uncertainty of maintenance costs. Several companies have made a lot of effort to develop membranes for either nitrogen or carbon dioxide removal from methane streams and it seems that some of these membranes could have the capability to efficiently separate methane from all the major contaminant gases found in drainage gas [11–13]. In general, cost-effective and reliable membranes are still under development.

There are similarities between the behaviour of membranes and PSA adsorbents. Both the pore size and chemical nature of the membrane material makes it more likely for some components to be adsorbed into the pore at high pressure and released at low pressure. However, membranes can be operated continuously by maintaining a high feed pressure on one side and a low production pressure on the other, so the adsorbed components flow through the pores to be released on the low-pressure side. The simplest form of membrane for methane purification is one that preferentially allows methane to pass through, while other gas species pass through only in minor concentrations.

The major limitation of membrane technology is in the scaling of the membrane modules. To give the structural rigidity that is required due to the pressure differential, membranes are typically supplied in spiral wound modules. The pressure drop and the risk of damage to the module limit the size of the modules, as the membrane cannot be repaired if damaged and the entire module will require replacement.

3.1.5. Discussion of the purification processes

Table 3 lists basic characteristics and differences for the above four purification technologies. In addition, the individual technologies for rejecting nitrogen, carbon dioxide, oxygen, and water could be combined in a system consisting of any combination of two or more of the four rejecting processes working together on variable quality and flow gas stream. Several small scale demonstrations of drainage gas purification have occurred at different sites [6] and a cryogenic purification plant is now operating commercially on drainage gas in the USA, with other installations likely in the future due to rising natural gas prices. Nitrogen rejection is the most critical and expensive component of any purification system, and is still an emerging and developing technique. Carbon dioxide and water removal techniques are very well established. Deoxygenation is used in other industries, but is less well established. Nitrogen rejection is not well established with respect to post-drainage gas field conditions because it operates mostly on relatively rich natural gases that are not subject to large changes in flow and concentration [6]. In the following, several potential technical issues that are relevant to purifying coal mine methane from pre- and post-drainage gas to pipeline specification are discussed.

3.1.5.1. Particulate removal. The processes addressed above include various items for other plants that are necessary to ensure reliable operation, mostly for pre-processing of the gas to avoid particulate erosion, compressor damage and explosion risk. The different processes have slightly different specifications for the feed gas quality, with the most common requirements being particulate removal, oxygen removal, drying and power generation.

3.1.5.2. Oxygen removal. Deoxygenation is generally the first process component for the purification process to minimise the risk of combustion in any gas compression stages. An exception is likely to be the pressure swing adsorption process, as most of the oxygen is removed along with nitrogen in the nitrogen rejection unit [6]. Some manufacturers of gas processing plants recommend that oxygen be removed to avoid the risk of explosion during compression, especially in cryogenic processes where the gas is liquefied. However, there is a dissenting view from some manufacturers that have operated plants without this precaution and without problems, so this is a decision that will require a risk assessment in consultation with the plant manufacturer at the time of plant specification.

Oxygen removal is generally performed using a catalytic process that removes the oxygen by oxidising some of the methane to carbon dioxide. As it removes some of the methane that would otherwise become product, this can have an impact on the operating economics if the oxygen concentration is significant. The catalyst also requires that the gas stream be heated to approximately 400 °C, which can be performed by heat exchange with the gas exiting the catalytic reactor if there is enough methane oxidised to raise the gas temperature sufficiently. Therefore, if the oxygen concentration is low, an energy input will be required to heat the feed gas to 400 °C and this will add to the operating cost of the process.

3.1.5.3. Water vapour removal. Drying of the gas is also required before cryogenic processing so that the gas can be compressed to high pressures and cooled without forming ice deposits. Drying is achieved in the process simulation by adsorbing the moisture on zeolite in a vessel. When the zeolite is saturated blowing hot dry air through the vessel regenerates it. An alternative process option that can be used is the use of glycol solvent to adsorb the water; this is essentially equivalent and negligible design and cost differences would occur due to a change from one option to the other.

3.1.5.4. Concerns about the application of purification technologies. Pressure swing adsorption processes are common at this scale in a variety of industries for different applications and offer no particular problems in operation and maintenance. In addition, as a semi-batch process it offers substantial flexibility with regard to fluctuating flow rate and composition. Mine gas fluctuations resulted in significant product gas quality fluctuations in a pilot plant test of PSA at a CONSOL Energy site in the USA [14], however, with an improved control system and instrumentation it should be possible to provide a product gas flow of the desired composition from feed with a wide range of properties.

Cryogenic plants are also widespread in use and are a very robust plant item, however, the scale of this operation would be smaller than typical cryogenic plants and this may result in operational problems, such as blockages caused by pipe freezing. The major concern with the use of a cryogenic system in this application is the variability in feed flow rate, as there is a limited range of operability for the separation columns in the plant. Recycling of streams to improve the consistency of operation can compensate for this to some extent, but this would lead to some increase in plant operating costs. Therefore, a criterion for adoption of a cryogenic plant design would be the ability of the mine to operate with a near constant drainage gas flow rate, or sizing the plant to use only a minor portion of the mine gas.

Membrane plants are being increasingly used in industry, but generally in small-scale applications. The compact modular nature of the plants makes them attractive for small retrofitting applications, however the large number of modules required for even medium size plants can be a disadvantage. There are also concerns about the durability of the membrane modules, as the membranes typically cannot be repaired, and if damaged, the whole module must be replaced. The module arrangement simplifies the installation of plant, but the large numbers required may make the plant difficult to maintain and operate.

The quality of feed in mine methane can be extremely variable, with a significant part of this variation arising from leaky piping that allows air contamination of what would otherwise be a saleable quality product with a minimum of processing. It is likely that most mines could adjust their operating procedures to produce a higher quality drainage gas and would do so if the gas was a profitable product. This improvement would substantially reduce the cost of purifying the gas to pipeline quality and any mine considering implementation of this technology to treat the gas should determine the achievable drainage gas quality for the mine before performing any design and economic analysis. If air contamination can be reliably stopped, the solvent adsorption processes could also be feasible. These would be expected to be comparable to the pressure swing adsorption method on an economic basis.

With regard to the technical and economic viability given typical mine methane flows, based on a process and cost modelling study, Beath [4] has concluded:

- It is unlikely to be practical to purify gas streams with less than 40% methane and even an overly expensive design would release substantial greenhouse gas emissions in dilute methane waste streams;
- Gas streams with methane contents between 40 and 70% can be processed to pipeline quality, but the process would lose money unless some subsidy is available for greenhouse gas mitigation; and
- If the gas stream has methane content greater than 70% it should be possible to install a plant that can purify the gas, and yield a reasonable return on investment, if the gas can be used locally or sold to a pipeline operator adjacent to the site.

3.2. Power generation

Generating electricity is an attractive option because most coal mines have significant electricity loads. Electricity is required to run nearly every piece of equipment including mining machines, conveyor belts, desalination plants, coal preparation plants, and ventilation fans. Ventilation systems in particular require large amounts of electricity because they run 24 h a day, every day of the year. In the USA, about 24 kW h of electricity are required per ton of coal extracted for the mine and 6 kW h of electricity are required per ton of coal processed in the coal preparation plant [15]. Generally, there are three potential

Table 4
A comparison of mine methane-fired stationary power generation technologies

Technology	Gas engines	Gas turbines	Fuel cells	Co-firing in power stations
Mechanism	Combustion	Combustion	Electrochemical reaction	Combustion/reburning
Operating temperature	1800–2000 °C	1400–1650 °C	150–200, 600–950 °C	1400–1650 °C
Minimum CH_4 requirement	40% (spark-ignition) [2,5], 5% (homogenous charge compression ignition) [52,53]	30% (conventional), 1% (catalytic turbine) [54]	Pre-drainage gas and medium quality post-drainage gas (>50%) [5]	Not determined
Potential issues			Still under development, high cost	Limited sites

technologies that can be used for stationary power generation by directly using pre- and post drainage gas, namely gas engines, gas turbines and fuel cells, when the methane concentration meets the requirement of the individual technology. However, it would be expected that variation of methane concentration and supply continuity of the drainage gas should affect the continuous and stable operation of the power generation units. Table 4 summarises the principles and differences of these three coal mine methane power generation technologies, and co-firing of coal mine methane in coal-fired power stations, which will be discussed later.

3.2.1. Internal combustion gas engines

Internal combustion engines commonly use medium-quality gas to generate electricity, and also, as discussed in Section 4.2.3, are good candidates for beneficially using part of a ventilation air stream by substituting it for fresh ambient air in the combustion air intake. There are two primary reciprocating engine designs of interest: the spark ignition Otto-cycle engine and the compression ignition Diesel-cycle engine. The essential mechanical components of the Otto-cycle and Diesel-cycle are the same.

At Nelms No. 1 mine (Ohio, USA), a 225 kW Synchronous Skid-Mounted IC engine, manufactured by General Motors, was installed by Northwest Fuel Development with the assistance of the US DOE. Properly configured carburettors in this light truck engine allow for the use of fuels ranging from 20 to 80% methane [5]. At Appin Colliery (NSW, Australia), 54 one-megawatt Caterpillar 3516 spark-fired engines are installed, and two sources of methane, gas from in-seam bore holes in advance of mining and gas from gob wells, supply the primary fuel for the project [2]. The fuel gas composition varies from 50–85%, 0–5% CO_2, and up to 50% air [6].

Typically, it is assumed that a minimum methane concentration of 40% is required for spark ignition engine operation, however, this has not been substantiated by thorough investigation. Studies on the homogenous charge compression ignition engines have indicated that this type of engine may be operated at methane concentration as low as 5%, based on an experimental study [52] and a modelling study [53] showing that this type of engine can be run on natural gas at a fuel–air equivalence ratio of as low as 0.3.

3.2.2. Conventional gas turbines

Gas turbines are a complex device based on advanced mechanical design work and have a major application in aircraft propulsion. Versions are also used extensively in the power generation industry for more flexible distributed power systems, base-load power, peak lopping engines, combined heat and power systems, and standby generators for emergency use [17]. The basic principle of gas turbine operation, involves a working gas (air) being compressed and heated by the combustion energy released from injected fuel, the turbine then converts the energy of the working gas into rotating energy through interaction between the gas and the blades.

No matter which type of gas turbine: open cycle (internal type) and closed cycle (external type), the basic components are an air compressor, a combustor and a turbine.

The gas turbine can handle a larger gas flow than that of the reciprocating internal combustion engines, because it utilises a continuous combustion process, so is suitable for use as a high power engine [18]. The use of gas turbines, including microgas turbines, to generate power has been demonstrated at coal mines using medium quality mine drainage gas. Improvements made to gas turbine designs in recent years results in greater efficiency, longer service life, and lower overall maintenance cost [5] than earlier designs.

When considering methane combustion, it is feasible to design a combustor with a stable flame when the heating value of the drainage gas is higher than approximately 10 MJ/m^3, which corresponds to about 30% CH_4. Therefore, conventional gas turbines with modified combustors should be able to use post- and pre- drainage gas that contains methane over 30% where there are no problems with supply continuity. Moreover, if a gas turbine system employs a catalytic combustor, the turbine system can operate continuously with only 1% methane in air, with the potential to operate as low as 0.8% methane [19,20]. This will be discussed in detail in Section 4.3.2.

3.2.3. Fuel cells

A fuel cell produces electricity by means of an electrochemical reaction, according to similar principles similar to a standard battery. To date, the only fuel cells with proven reliability utilise hydrogen as the fuel, but development of methane-powered fuel cells is continuing.

Three types of fuel cells: phosphoric acid, molten carbonate and solid oxide are being developed for power generation. Phosphoric acid fuel cells are currently the most commercially advanced type of fuel cell with efficiency from 40 to 80%, operating at a temperature of 150–200 °C [21]. Coal mine methane can play a role in the production of hydrogen as a means of external hydrocarbon fuel reforming to fuel such stationary fuel cells. However, the molten carbonate and solid oxide fuel cells operate at high temperatures (from 600 to 950 °C), and the high temperatures mean that these fuel cells are able to internally reform hydrocarbons and generate hydrogen within the fuel cells, so they can directly use hydrocarbon fuels such as coal mine methane. The minimum methane concentration requirement for such application needs to be investigated, and it has been indicated that the fuel cells can operate on methane from mine pre-drainage and medium quality post-drainage gas [5]. From this it is estimated that the minimum methane concentration could be 50%.

Nevertheless, the current cost of fuel cells is high and this tends to preclude commercial application. In addition, the high temperature fuel cells are still under development to reduce capital cost and increase reliability. It would be expected that fuel cell technology could have great potential application if a technology breakthrough happens in the future that results in cost reduction and improved reliability.

3.2.4. Co-firing in power stations

The original objective of co-firing natural gas in conventional coal-fired power stations was to reduce NO_x emissions from the power stations [22,23], namely through reburning or fuel staging. Fig. 2 illustrates the principle of reburning technology and reburning demonstrations using natural gas at several power stations have demonstrated that the NO_x emissions can be reduced up to 60% when the methane comprises 10–20% of the total heat input [23]. The reduction of NO_x primarily occurs in the reburning zone [24]. The following is a major chemical pathway of NO_x reduction starting with hydrocarbon radicals and ending with the reverse Zeldovich reaction of converting N to N_2 [23]

$$NO + CH_4 \rightarrow HCN \rightarrow NCO \rightarrow NH \rightarrow N \rightarrow N_2$$

If the percentage of the reburning fuel is too high, it can lower the steam production rate of the boiler. This is due to the radiative heat transfer being reduced, a result of lower flame emissivity caused by lower particulate concentrations.

One potential and practical option is that coal mine methane can be used for cofiring at coal-fired power stations as the reburning fuel [25]. The benefits of the cofiring are: mitigation and utilisation of the coal mine methane, power generation with less CO_2 emission, significant reduction of NO_x emissions and lower capital costs than standalone plants. However, the following potential issues should be considered for the application of the reburning technology.

- Limited sites suitable for the application of this technology due to the requirement of having an existing power stations near the coal mine,
- A need for mine methane transportation lines, which adds to the cost of the modification, and
- Variations in methane concentration and supply rate would affect the operation of power stations.

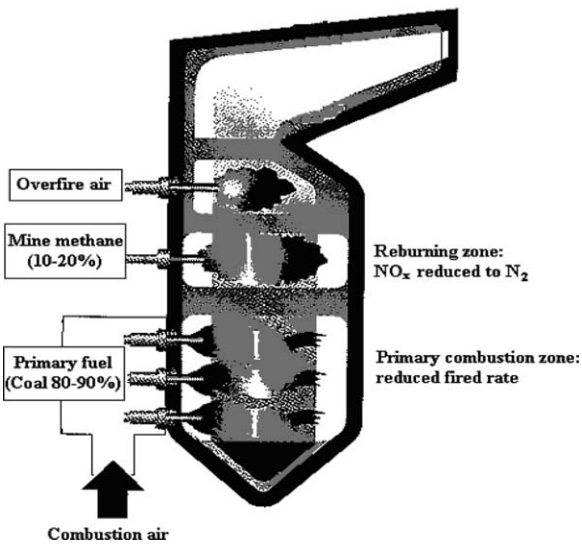


Fig. 2. Principle of reburning technology (modified from [24]).

3.3. Chemical feedstocks

An alternative use of coal mine methane can be as a chemical feedstock for different chemical processes for the production of synthetic fuels and chemicals. Two potential applications in this field are methanol production and carbon black production. Table 5 compares features and differences of these two technologies.

Table 5
A comparison of methanol and carbon black production technologies

Technology	Methanol production	Carbon black production
Mechanism	Syntheasis reaction	Gas reduction reaction
Operating temperature	130–1000 °C [55]	1250–1400 °C [56]
Minimum CH_4 requirement	89% [5,55]	Pre-drainage gas and medium quality post-drainage gas (>50%) [5]
Potential issues	Process water required	Process water required

3.3.1. Methanol production

Methanol (CH_3OH) can be used either as a fuel or as an ingredient in the synthesis of more complex chemicals. It is a key component of many products, including MTBE (used in reformulated gasoline), methanol and gasoline blends (such as M85 for flexible fuel vehicles), formaldehyde resins (widely used in the housing industry), and acetic acid [5]. Most of the world's methanol is produced using natural gas as a feedstock, so the ability to produce methanol from feedstocks such as coal or biomass is of interest to reduce costs. Coal mine methane is a potential alternative feedstock to fuel large methanol plants that are near gassy mines. Smaller (11.4–15 million l/yr) mobile methanol plants used at off-shore oil rigs may be a potential option for use at coal mines. Gas quality should be at least 89% methane, but can include up to 1% oxygen and up to 10% carbon dioxide for this application [5,55,26]. Therefore, the process requires a relatively high quality coal mine methane supply, such as the pre-drainage gas from some coal mines, so mines with lower quality gas will not be suitable.

Typically, the methanol production process consists of four main steps, namely feed gas preparation, syngas production, methanol synthesis and distillation. However, new technologies are being developed to improve the efficiency and costs of the process.

3.3.2. Carbon black production

Carbon black is used as a reinforcing agent in rubber compounds (especially tires) and as a black pigment in printing inks, surface coatings, paper, and plastics). It is also important to the electric and electrochemical industries (cells, conductive plastic) and the dry battery industry. The demand for carbon black is growing rapidly. Currently, raw materials for most carbon black plants are natural gas and crude oil. Alternatively, coal mine methane is a potential raw material for carbon black production. The China Carbon Black Institute (CCBI) has demonstrated its semi-reinforcing gas furnace carbon black production technology at Baijgou Coal Mine in China [27]. Fig. 3 shows a simplified diagram of the semi-reinforcement gas furnace carbon black production technology.

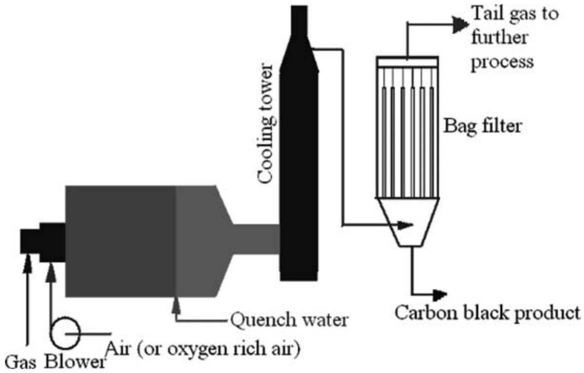


Fig. 3. A simplified diagram of the semi-reinforcement gas furnace carbon black production technology [28].

The benefits of the technology are that: (1) it easily copes with gas supply variability and variable methane concentration, if the methane concentration can be maintained greater than 50%; (2) carbon black is a readily marketable and value-added product; and (3) carbon black is easy to transport if mines are in remote areas.

3.4. Summary

At the current stage of development of the technologies evaluated, it appears that the following technologies are potentially technically feasible for application at mine sites, and therefore would be suitable subjects for economic assessment as case studies in Section 5:

- Purification—pressure swing adsorption,
- Internal combustion engine,
- Conventional gas turbines,
- Methanol production,
- Carbon black production.

A significant limitation is that the minimum methane concentration for methanol production is 89% and, unfortunately, the case study data indicates that the probability of methane concentration being greater than 89% is only 7.7, 3.2 and 1% for pre-drainage gas, post-drainage gas and the mixture of pre- and post-drainage gas at the site, respectively. Therefore, it appears that methanol production is unlikely to be feasible at most mine sites and it will, therefore, not be the subject of further evaluation. In most cases it will not be feasible to produce methanol using coal mine drainage gas without addition of high quality gas, because of the requirements for minimum methane concentration and gas supply continuity, and this significantly reduces the applicability of the process to the case study mine.

The carbon black production plant referred to in China uses coal bed methane with a minimum methane concentration of 84%. This has similar application problems to the methanol production process, namely that the case study data indicates that the probability of the methane concentration being sufficient is only 23.3, 8.5 and 5.6% for pre-drainage gas, post-drainage gas and the mixture of pre- and post-drainage gas at the site, respectively. The oxygen-enriched air carbon black production technology could lower the minimum methane concentration to 50%, but this needs to be demonstrated in pilot-scale. No further evaluation of the carbon black process will be performed due to this limited applicability at the case study coal mine.

4. Progress in developing technologies for ventilation air methane

4.1. CH_4 oxidation mechanisms

The mechanisms for ventilation air methane mitigation and utilisation generally use thermal oxidation or catalytic oxidation. The overall combustion mechanism of methane may be represented by the following equation

$$CH_4 + 2O_2 = CO_2 + 2H_2O, \quad \Delta H_{(298)} = -802.7\ \text{kJ/mol}$$

However, this is a gross simplification, since the actual reaction mechanism involves many free radical chain reactions [29]. The combustion of methane may produce CO or CO_2 depending on the air/methane ratio by the reactions

$$CH_4 + 2O_2 = CO_2 + 2H_2O$$

$$CH_4 + 3/2O_2 = CO + 2H_2O$$

Other reactions may also be present, such as:

$$CH_4 + H_2O = CO + 3H_2$$

$$2H_2 + O_2 = 2H_2O$$

$$CO + H_2O = CO_2 + H_2$$

Studies of the kinetic mechanisms of methane catalytic combustion can become quite involved when multi-step surface reactions are considered. Chou et al. [30] used 23 different reactions in their numerical study of methane catalytic combustion in a monolith honeycomb reactor. The situation becomes even more complicated when considering heterogeneous reactions. Fig. 4 shows a possible mechanism for methane catalytic oxidation, as proposed by Oh et al. [31].

In general, catalytic combustion is a multi-step process involving diffusion to the catalyst surface, adsorption onto the catalyst, reaction, and desorption of the product species from the catalyst surface and diffusion back into the bulk. Most kinetic investigations have been performed in conditions where methane is present in excess of the stoichiometric ratio. The result of this is that the reaction has generally been found to be independent of the oxygen concentration. The reaction order with respect to methane is typically found to be between 0.5 and 1 [29]. Lee et al. [29] and Ledwich et al. [32] summarised information on the results of various experiments and the activation energies and reaction orders calculated and noted that the activation energies are quite variable, being dependent on the catalyst and operating temperature. No firm agreement has been reached concerning the kinetic mechanism of methane catalytic oxidation. They indicated that platinum and palladium are generally accepted as the most active catalysts for low temperature total oxidation. Other catalysts have been tested but are less active. Lee et al. [29] noted that, although the experiments were conducted at various conditions, it is clear that Pd/Al_2O_3 is by far the best catalyst, with Pt/Al_2O_3 the next most active.

4.2. Ancillary uses of ventilation air methane

Ancillary uses of ventilation air generally involve substituting the ventilation air for ambient air in combustion processes. This has the advantage that methane in the ventilation air acts as a supplementary fuel in the combustion processes, potentially improving combustion performance. As classified in Fig. 1 and Table 2, processes that can utilise ventilation air in this manner include:

- Pulverised coal-fired power stations,
- Hybrid waste coal/methane combustion units,
- Gas turbines, and
- Internal combustion engines.

Table 6 compares technologies for ventilation air methane ancillary use with respect to the main operational parameters, combustion method, technical feasibility and engineering applicability. Generally, energy recovery of the processes will be certain for these technologies. 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.

4.2.1. Pulverised coal-fired power stations

If ventilation air can be delivered to a large fuel consumer, such as a coal-fired power station boiler, it can readily replace ambient air for all or part of the combustion air requirements. 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 [2]. A full-scale

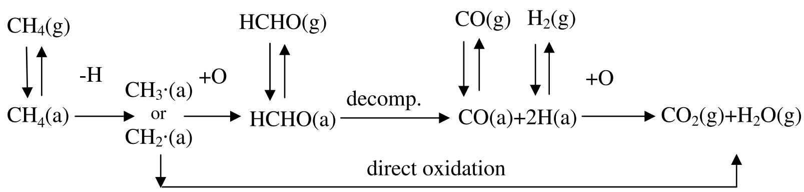


Fig. 4. A possible mechanism for methane catalytic oxidation [31]: (a) adsorbed, (g) gas phase.

Table 6
Differences of ventilation air methane ancillary use technologies

Technology	Feature	Combustion temperature	Technical feasibility and engineering applicability	Potential issues
Pulverised coal-fired power station	Pulverised coal-fired furnace	1400–1650 °C [57]	Tech: yes Eng: not demonstrated at a mine site	Limited sites Potential operational problems to existing boilers
Hybrid waste coal/tailings/methane in a rotating kiln	Rotating kiln	1200–1550 °C	Tech: may be Eng: not demonstrated at a mine site	Self-sustaining combustion Minimum requirement for waste coal/tailings quality
Hybrid waste coal/tailings/methane in a fluidised bed	Fluidised bed	850–950 °C [58]	Tech: maybe Eng: not demonstrated at a mine site	Minimum requirement for waste coal/tailings quality Proving test needed for CH_4 oxidation
Conventional gas turbines	Gas turbine	1400–1650 °C [59]	Tech: maybe Eng: not demonstrated at a mine site	Small percentage of turbine fuel A lot of CH_4 is emitted in by-passing air for a single compressor machine. If two compressors are used there is increasing system complexity, and decreasing capacity of using ventilation air
Internal combustion engines	Engine	1800–2000 °C [53]	Tech: yes Eng: demonstrated at a mine site	Small percentage of engine fuel Using a small percentage of ventilation air

Tech, technical feasibility; Eng, engineering applicability.

demonstration of this technique at this power station is being planned with the support of an Australian federal government program [33]. In this demonstration, the ventilation air will 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.

In general, power stations are not convenient to all gassy mines and this limits the suitability of this technique. Technically, for existing pulverised coal-fired power stations variations of methane in ventilation air might affect a stable operation of the conventional power station boiler furnaces depending on the methane concentration in air and the flow rate of ventilation air. This also increases the complexity of power station operation, which needs to be evaluated in terms of power station efficiency, power station and mine safety. It is possible that a quick increase in the methane concentration in combustion air from 0 to 0.8% could result in damage to the boiler due to increased combustion temperatures, and increased slagging and fouling problems if control is inadequate.

4.2.2. Hybrid waste coal/tailings/methane combustion units

With regard to the methane oxidation mechanism and the method of replacing combustion air with ventilation air, using ventilation air in hybrid waste coal/tailings/methane combustion in either a rotating kiln or a fluidised bed is similar in concept to the use of ventilation air in pulverised coal boilers. However, there are some extra requirements when organising and stabilising the combustion processes utilising low quality fuels.

4.2.2.1. Rotating kiln. CSIRO has been developing a coal mine waste methane/coal utilisation technology, with the aim of not only mitigating mine methane and waste coal, but to also recover energy for power generation. It is expected that waste coal could be combusted with mine methane from both drainage gas and ventilation air inside a rotating kiln. For low quality waste materials, it is likely that the drainage gas flame will play an essential role in stabilising the combustion process inside the kiln. At present, several major operating parameters of the combustion process need to be further investigated to determine the potential for large-scale implementation. Some combustion tests have been conducted in a 1.2 MW_t rotating kiln. Preliminary results suggest that the combustion performance of waste coal needs to be tested systematically to determine the feasibility of waste coal combustion inside the rotating kiln and to obtain the optimum operating parameters. It is difficult to sustain combustion without a pilot flame burning a higher quality fuel, such as drainage gas. In the absence of sufficient supply of gaseous fuels it is likely that higher quality coal would be required to sustain combustion.

In the early 1990s, Cobb [34] examined the combustion performance of waste coals in a rotary kiln. The test results were disappointing, and showed that it was difficult to maintain sustained combustion even when large quantities of supplemental fuel were used. Combustion efficiency was poor, around 60%. The rotary kiln is ill-suited with respect to low-grade, hard to burn solid fuels, such as anthracite culm. Indeed, data from combustion of bituminous coal in the kiln unit suggest that with respect to coal in general, the rotary kiln boiler appears inferior to the circulating fluid bed boiler.

The rotary kiln has an 'open structure' which earmarks it for mass burn applications involving bulky and 'gooey' fuels and wastes.

4.2.2.2. Fluidised bed. Fluidised beds suspend solid fuels on upward-blowing jets of air during the combustion process. The result is a turbulent mixing of gas and solids. The tumbling action, much like a bubbling fluid, provides for high chemical reaction rates and heat transfer. This technology burns fuel at temperatures of 800–950 °C, well below the threshold where nitrogen oxides form (at approximately 1350 °C, the nitrogen and oxygen atoms in the combustion air combine to form nitrogen oxide pollutants). The mixing action of the fluidised bed can bring the flue gases into contact with a sulphur-absorbing chemical, such as limestone or dolomite, that has been added to the bed. There are 14 CFBC power plants in Pennsylvania burning waste coals including anthracite culm. These power plants successfully operate using advanced CFBC technology and can directly fire unprocessed waste coal with ash content ranging from 50 to 70% by weight, corresponding to a heating value of 7 MJ/kg (the minimum requirement for stable boiler operation) [35].

However, with regard to hybrid waste coal/methane fluidised bed combustion, there has been no experimental study that proves the methane will be fully oxidised in a fluidised bed combustion unit. A study of this kind should be carried out before the development of larger-scale units for this purpose.

4.2.3. Internal combustion engines

Internal combustion engines commonly use medium-quality gas to generate electricity, and are suitable for beneficially using part of a ventilation air stream by substituting it for fresh ambient air in the combustion air intake. This is a low capital cost option for ventilation air mitigation if the distance to the engines is minimal. As indicated in Table 6, this approach may emit more NO_x than the other technologies due to the higher temperatures reached in the combustion chamber.

At Appin Colliery (NSW, Australia), 54 one-megawatt Caterpillar G3516 spark-fired engines have been installed to use drainage gas as the primary fuel. The operation of these engines has demonstrated that methane from ventilation air only contributes between 4 and 10% of engine fuel, corresponding to the consumption of only approximately 20% of the ventilation emissions [2]. The engines do not currently use any ventilation air due to supply and maintenance issues. It is likely that, at most mines, only a small percentage of methane from ventilation air could be used by this technology.

4.2.4. Conventional gas turbines

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 normal industrial gas turbines will result in a significant fraction of the methane passing through the turbine without combusting. To avoid this, a more complex turbine system that requires compressed air from other sources, as well as compressed ventilation air, is required [19,36,37]. The Solar turbine company has specified that the air fed to the compressor must contain less than 0.5% methane to protect the unit's cooling system from possible combustion. A richer mixture might support combustion and cause a dangerous temperature rise in the interior of the rotor [37].

4.3. Principal uses of ventilation air methane

Principal uses of ventilation air involve combustion of the methane in ventilation air as the primary fuel and a selection of these uses were classified in Fig. 1 and Table 2.

It should be pointed out that the definition of 'primary fuel' is not exact for some technologies depending on the CH_4 concentration in air and the minimum CH_4 concentration for the operational requirement, particularly where a lot of supplementary high quality fuel is required to make it possible to generate power.

4.3.1. TFRR, CFRR and CMR technologies

Principles of the thermal flow reversal reactor (TFRR) and catalytic flow reversal reactor (CFRR) technologies have been already described elsewhere [37,38,54]. Both TFRR and CFRR employ the flow-reversal principle to transfer the heat of combustion of the methane to the incoming air via a solid heat storage medium. This is required to raise the ventilation air temperature to the ignition temperature of methane. The two systems differ only with respect to the use of a catalyst in the CFRR technology [54]. Catalytic monolith reactor (CMR) technology uses a honeycomb type monolithic reactor, a type of reactor in common use due to its outstanding characteristics of very low pressure drop at high mass flows, high geometrical area, and high mechanical strength [39]. Monoliths consist of a structure of parallel channels with walls coated by a porous support containing catalytically active particles. Therefore, compared with the TFRR and CFRR units, the CMR unit should be more compact in terms of processing the same amount of ventilation air, but will require a recuperator to pre-heat the ventilation air. This is in contrast to the regenerative beds of the TFRR and CFRR units. Table 7 summarises the features of the TFRR, CFRR and CMR technologies.

4.3.1.1. Minimum methane concentration. As previously discussed, the volume of ventilation air is very large and the methane concentration is low and variable. This is likely to cause operational problems when using TFRR and CFRR technologies by making it difficult to maintain continuous operation and recover heat to generate electricity. For example, though MEGTEC has stated that the TFRR unit

Table 7
Comparison of the methane mitigation technologies

Feature	MEGTEC TFRR	CANMET CFRR	CSIRO CMR
Principles of operation	Flow reversal	Same as TFRR	Monolith reactor
Catalyst	No	Yes	Yes
Auto-ignition temperature	1000 °C	350–800 °C	500 °C
Experience	600+units in field, some operating on methane	Bench-scale trials with simulated mine exhaust	Bench-scale study on combustion
Cycle period length	Shorter	Longer	Continuously
Minimum CH_4 concentration	0.2%	0.1%	0.4%
Applicability	CH_4 mitigation	CH_4 mitigation	CH_4 mitigation
Possibility of recovering heat to generate power	May need additional fuel to increase CH_4 concentration and maintain it constant	May need additional fuel to increase CH_4 concentration and maintain it constant	May need additional fuel to increase CH_4 concentration and maintain it constant
Variability of CH_4 concentration	Variable	Variable	Variable
Plant size	Huge	Larger	Compact
Operation	More complicated	More complicated	Simple
Lifetime	N/A	N/A	>8000 h for catalysts
NO_x emission	N/A	Low	Low (<1 ppm)
CO emission	Low	Low	Low (∼0 ppm)

can continue to function at concentrations of 0.08% methane, simulation results by The University of Utah indicated that temperatures would drop below the minimum required if the methane concentration drops below 0.35% [2]. Danell et al. [38] carried out trials in a pilot-scale TFRR unit attached to the ventilation air shaft of Appin Colliery, and reported that the unit can be operated with CH_4 concentration as low as 0.19%, however, they did not report how long the continuous operation lasted at such concentration. Indeed, it is a practical issue in terms of mine-site operation as the methane in ventilation air could be lower than 0.19% for periods ranging from a few hours to a few weeks. Recent communications with CONSOL Energy indicated that the minimum methane concentration guaranteed by MEGTEC for continuous operation is 0.2% [40]. Two full-scale demonstration units processing 28 m^3/s will shortly be installed at the bleeding shaft of a mine in Pennsylvania which contains methane from 0.9 to 1.5% [40]. It has been indicated that over 200 operators of the TFRR units regularly add natural gas to the industrial airflows to maintain combustion [2].

To sustain the CFRR operation, the minimum methane in the ventilation should be above 0.1% [2,41]. It is unclear how long the CFFR unit can be operated on 0.1% methane in air. According to the experimental catalytic combustion results obtained in a CMR laboratory-scale rig, the CMR can be continuously operated when methane concentration is greater than 0.4% and the air is preheated up to 500 °C by a recuperator using flue gas from the CMR [19,36], so it is likely that the CFRR requires similar conditions for continuous operation.

4.3.1.2. Technical feasibility and applicability. Some mine sites have low power usage rates and do not have a need for any additional power, or have variable power needs. Therefore, these mines are interested in investigating means of simply destroying ventilation air methane without generating power. There could be no doubt that the TFRR, CFRR and CMR technologies are technically feasible for this purpose when the methane concentration in air exceeds the minimum requirement by each technology and economic performance is not critical.

With respect to engineering applicability, these technologies can be used to destroy methane in ventilation air as methane mitigation technologies. However, for some mine sites the continuous operation of these units may need additional fuel to maintain sufficient temperatures and/or methane content for combustion to occur. It is interesting to note the size of the two TFFR units that CONSOL Energy will install at a mine site to process 28 m^3/s ventilation air. The combined dimensions of the two units are 14.62 m long, 11.79 m wide and 4.49 m high. So, to process all of the ventilation air from a typical mine site the TFFR units will be approximately $63\times14.62\times4.49$ m for 150 m^3/s or $126\times14.62\times4.49$ m for 300 m^3/s, assuming the units are placed in a line. It is estimated, based on experimental data, that approximately one eighth of this area is required by the CMR to process the same amount of ventilation air. Therefore, the available space for equipment could be a deciding factor in the selection of technologies. The larger size of the TFRR and CFRR technologies gives an advantage in the handling of variable methane concentration in the ventilation air due to the thermal inertia of the systems. The CMR will require additional thermal storage in the recuperator to allow for any continuity of operation when the methane concentration drops below 0.4%.

4.3.1.3. Heat recovery. If the methane concentration and ventilation air flow rate are approximately constant, recovery of the heat released by methane combustion can

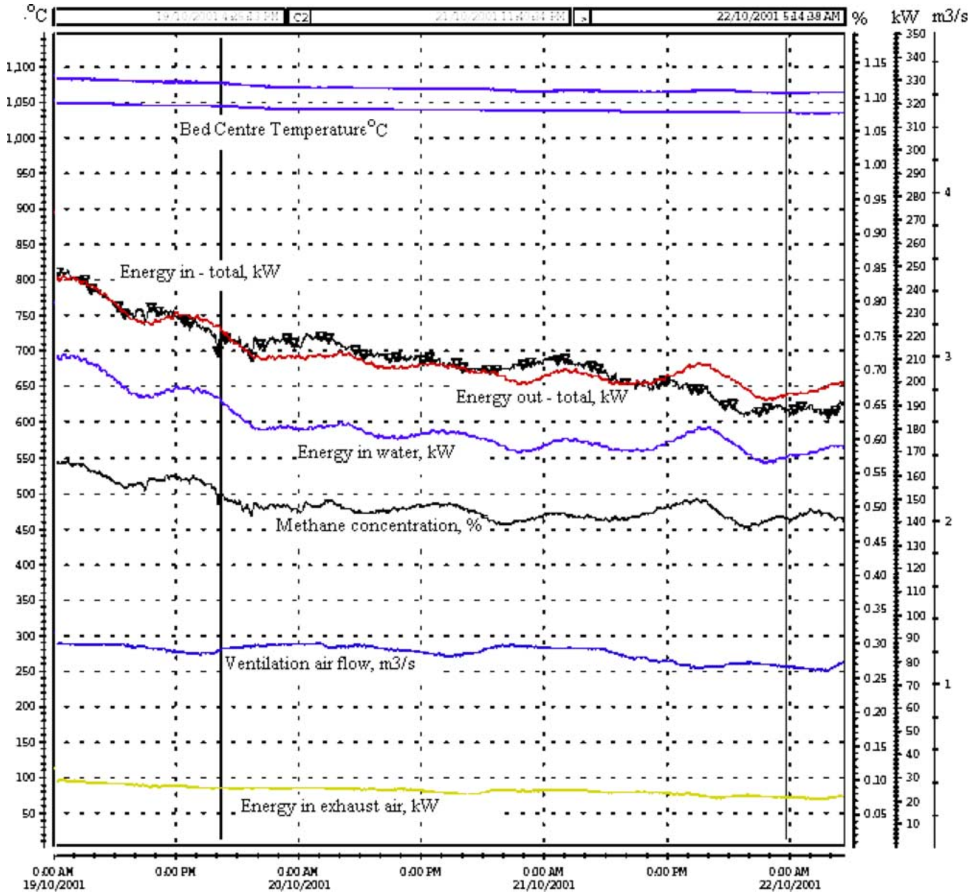


Fig. 5. TFRR test unit operating chart (extracted from [38]).

be used to generate power. If the methane concentration or ventilation air flow rate are variable, it is difficult to extract useful energy as the variations in heat release are likely to cause instability in the system and it will be difficult to maintain the working fluid that recovers the heat at a constant temperature and flow rate. 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.

It should be possible to recover surplus heat from the systems described when they are operating with methane concentrations above the minimum. This needs to be transferred into a working fluid, such as hot water/steam for a steam turbine or air for a gas turbine. Some of the heat is required to maintain reactor temperature, and if methane concentrations are in the lowest sustainable range, most or all of the heat of combustion goes for maintaining the reactor temperature. However, this heat recovery process depends on whether the methane concentration in the ventilation air is almost constant or not. When the methane concentration is variable, it is difficult to use normal heat exchangers (steam or hot air production) to cope with the reactor temperature variations. This has been demonstrated by the experimental results obtained by Danell et al. [38] in the pilot-scale TFFR unit. The heat absorbed by cooling water is very sensitive to the methane concentration in air. Fig. 5 is an example that shows this sensitive relationship. This is because the heat flux from the combustion side to the cooling water is almost dependent on the temperature approach that is determined by methane concentration in air rather than heat transfer area and heat transfer coefficient that are almost constant once the heat exchanger is installed into the bed. This can be mathematically described, i.e.

$$Q = A\alpha\Delta T$$

where Q is the heat transferred from the combustion side to the cooling water, MJ/s; A is heat transfer area, m^2; α is the overall heat transfer coefficient, MJ/(m^2 s); and ΔT is the temperature approach between the combustion side and the cooling water, °C.

Assuming that a suitable heat exchanger could be designed, the temperature fluctuations in the steam or air being produced would result in instability in the operation of the attached turbine. Therefore, in order to recover heat for power generation while retaining stable operation of the reactor and attached turbine, it is necessary to maintain constant methane concentrations in the feed air, typically requiring addition of natural gas. As a practical application of technology, BHP Billiton plans to install a TFRR system combined with a conventional steam turbine at Appin Colliery (NSW, Australia). 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%. The two large units will consume approximately 57.5 m^3/s of ventilation air [33]. In addition, as previously mentioned, CONSOL Energy will evaluate the feasibility of power generation by recovering the heat from their demonstration units during 12 months of continuous operation [40]. It is expected that the performance data from the future full-scale demonstration units from Australia and USA should prove this analysis, i.e. that additional fuel is necessary for the power generation operation. MEGTEC recently reported that the supplementary fuel is used to cope with the variability and meet the minimum methane concentration for power generation, about 0.9% [42].

4.3.2. Lean-burn gas turbines

There are several lean-burn gas turbines being developed in the world. These include EDL's recuperative gas turbine, CSIRO lean-burn catalytic turbine and Ingersoll-Rand (IR)'s microturbine with a catalytic combustor [1]. Table 8 summarises the features of lean-burn gas turbines. The EDL technology is a recuperative gas turbine, which uses heat from the combustion process to preheat the air containing methane to the auto-ignition temperature (in the range 700–1000 °C), with the combusted gas being used to drive a turbine. Reportedly, this gas turbine can operate continuously when the methane concentration in air is above 1.6%, which leads to the air being preheated to 700 °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 receive $11 million to install and operate four 2.7 MW_e recuperative gas turbine generators at Anglo Coal's German Creek Mine (Queensland, Australia). The project is expected to achieve large-scale abatement much earlier than the 2008 deadline [33]. These gas turbines are modified Centaur units from Solar Turbines. All the pre-drainage, post drainage and some ventilation air are ingested into the intake of the axial compressor at a pressure of approximately −10 kPa. The mixture is preheated by a recuperator to 450 °C. Then a recuperative combustion chamber uses the hot combustion products to further heat the fuel–air mixture to a point where ignition occurs. The fuel and air mixture is injected through stainless steel tubes into the combustion region. The burnt gas then passes up the outside of the stainless steel tubes to heat incoming air, and then enters into the turbine inlet to drive the turbine. This heat exchange reduces the exit temperature of air to 850 °C, which is the same as the standard Centaur turbine. With this design, there is a need to use a turbine that has a low combustion temperature. This type of turbine has no bypass and no blade bleed cooling so that all the mine ventilation gas passes into the combustion chamber [43].

Reduction of the minimum methane concentration at which a turbine system can operate has substantial advantages

Table 8
Comparison of the lean-burn turbine technologies

Feature	EDL recuperative turbine	CSIRO catalytic turbine	IR catalytic microturbine
Principles of operation	Air heater inside combustion chamber	Monolith reactor	Monolith reactor
Catalyst	No	Yes	Yes
Auto-ignition temperature	700–1000 °C	500 °C	N/A
Experience	Pilot-scale trial	Bench-scale study on combustion	Conventional microturbine development
Cycle period length	Continuously	Continuously	Continuously
Minimum CH_4 concentration for operation	1.6%	1%	1%
Applicability	CH_4 mitigation and power generation and need additional fuel to increase CH_4 concentration	CH_4 mitigation and power generation and need additional fuel to increase CH_4 concentration	CH_4 mitigation and power generation and need additional fuel to increase CH_4 concentration
Possibility of recovering heat	Feasible (power generation)	Feasible (power generation)	Feasible (power generation)
Variability of CH_4 concentration	Constant	Constant	Constant
Operation	Simple and stable	Simple and stable	Simple and stable
Lifetime	May be shorter due to the high temperature combustion heat exchanger	>8000 h for catalysts, and 20 years for a turbine	N/A
NO_x emission	Higher (?)	Low (<3 ppm)	Low
CO emission	Low	Low (~ 0 ppm)	Low

in reducing usage of methane from other sources. Su et al. [19] from CSIRO (Australia) devised a 1% methane catalytic combustion gas turbine system based on methane catalytic combustion experimental data and the design criteria for a turbine system that is the subject of a patent application [44]. The 1% methane turbine can use a much greater proportion of ventilation air compared with a 1.6% methane gas turbine, if mine drainage gas is the only supplementary fuel used. In addition to the 1% methane turbine development in Australia, Ingersoll-Rand in USA is also developing a microturbine with a catalytic combustor powered with 1% methane in air. Thermodynamically, lean-burn catalytic turbines can be operated at lower methane concentrations, perhaps to 0.8% [1,19], but it is difficult to generate power below this. In general, the catalytic turbine intakes a very lean fuel/air mixture, compresses it, and combusts it in a catalytic combustor. The turbine operates at low temperatures, so does not use combustion air for dilution and internal cooling, thus allowing the air intake to contain methane.

A technical and economic assessment has been carried out on the implementation of 1 and 1.6% methane gas turbines on the basis of real methane emission data from two Australian gassy coal mines [20]. The results indicated that 50–100% of the fuel for firing the 1% methane catalytic turbine is the methane from ventilation air, compared to only 30–60% for the 1.6% methane recuperative turbine, depending on the methane concentration in the ventilation air. Also, the 1% turbine can utilise near 100% of ventilation air for both mines, but the 1.6% turbine uses only 50 and 36% of ventilation air for the two mines considered in the study.

4.3.3. Concentrator

Concentrators have been applied to several industries to capture volatile organic compounds. A concentrator of this type could be used to enrich methane in mine ventilation air to levels that meet the requirements of lean-burn methane utilization technologies, such as catalytic and recuperative gas turbines. This involves taking the 0.1–0.9% 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.

Environmental C & C, Inc. (ECC) manufactures a fluid bed concentrator and is conducting 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. A successfully demonstrated, cost-effective concentrator would be a useful technology for application in mine ventilation air processing, potentially allowing more cost-effective processing of the waste methane in a variety of plants, however, further development is required before the technology can be applied, and it is very uncertain. Unfortunately, recent experiments conducted by ECC on an adsorbent in a fluidised bed concentrator were disappointing, and the trials have stopped [42].

4.4. Summary

On the basis of the above technical assessment of coal mine methane mitigation and utilisation technologies, it is concluded that the following technologies are potentially feasible in terms of technology application for a broad range of mine sites at present, and they will be assessed in terms of economics in Section 5.

Mitigation of ventilation air methane

- TFFR technology,
- CFRR technology, and
- CMR technology.

Mitigation and utilisation of ventilation air methane

- EDL recuperative gas turbine technology, and
- CSIRO catalytic turbine technology.

5. Case study: a Queensland coal mine

5.1. Characteristics of methane emissions

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:

(1) Percentage of methane emitted from ventilation air stream,
(2) Variations in methane concentration and flow rate for ventilation air, pre- and post-drainage gas if any, and
(3) Methane concentration variation rate.

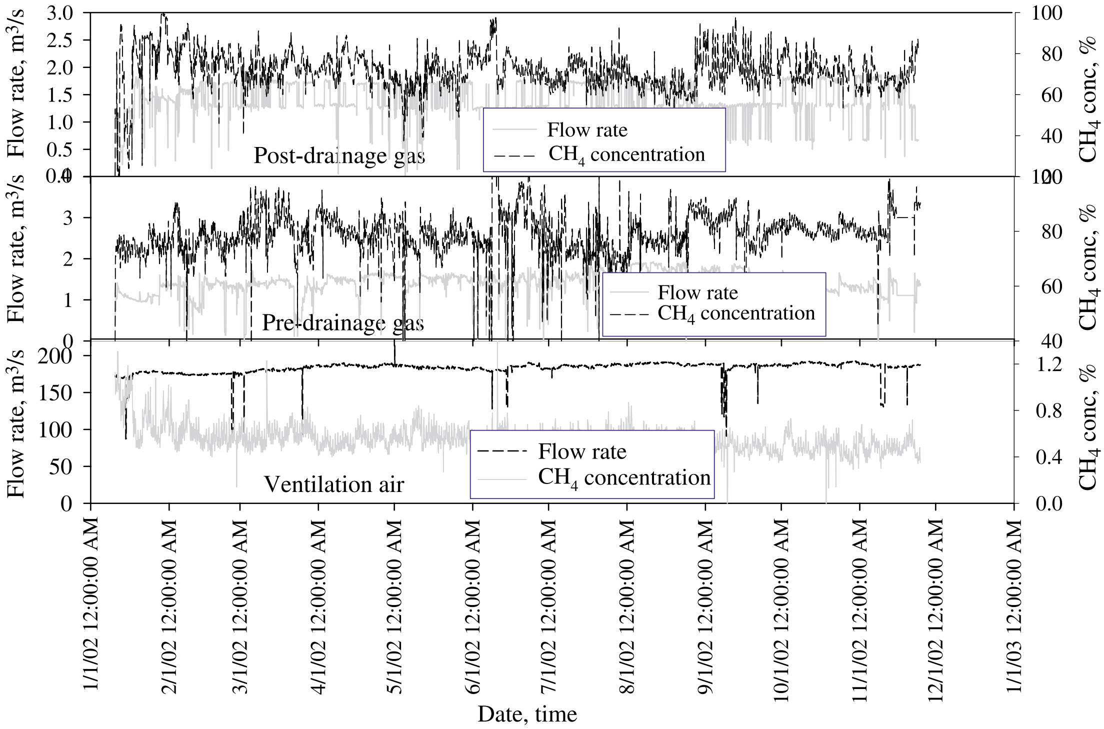


Fig. 6. Characteristics of methane emissions from a Queensland mine.

Fig. 6 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: 32,433,515 m^3/yr from the ventilation air, 66,475,933 m^3/yr from the drainage gas.
- Percent of methane emitted from the ventilation air is 32.8%.
- Most rapid methane variation rate is 0.01% CH_4/h.
- 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: 2.11 m^3/s.

In addition, it is estimated that the distance between the drainage gas plants and the ventilation air shaft is about 1000 m.

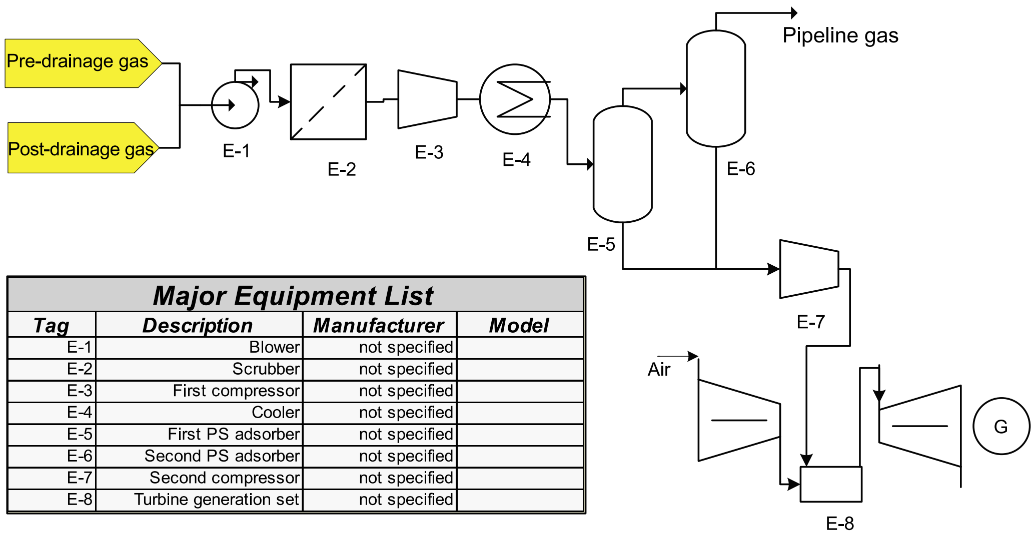
5.2. Basis for the economic assessment

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 the 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). Economic calculations for the plants use the following characteristics for the basic analysis:

- All costs in 2004 Australian dollars,
- Plant lifetime: 25 years,
- Installation cost: 10% of equipment capital cost,
- Discount rate: 7.5%,
- Electricity price: \$37/MW h [45],
- Natural gas price: \$5.05/GJ[1],
- 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. Other cases are

[1] Sale price to distributor assumed to be half of the bulk supply price to larger industrial customers of \$10.10/GJ. Origin Energy Retail (2003), Domestic, Commercial and Industrial Tariffs from July 1, 2003.



Major Equipment List			
Tag	**Description**	**Manufacturer**	**Model**
E-1	Blower	not specified	
E-2	Scrubber	not specified	
E-3	First compressor	not specified	
E-4	Cooler	not specified	
E-5	First PS adsorber	not specified	
E-6	Second PS adsorber	not specified	
E-7	Second compressor	not specified	
E-8	Turbine generation set	not specified	

Fig. 7. Diagram of a typical process for pressure swing adsorption purification of gas.

considered based on payment of carbon credits as given below [46,47][2]:

- Carbon credit: \$5/t $CO_{2\text{-e}}$,
- Carbon credit: \$10/t $CO_{2\text{-e}}$.

5.3. Potential technologies for drainage gas mitigation and utilisation

5.3.1. Purification by pressure swing adsorption

5.3.1.1. Potential and operating status. The key criteria for evaluation of methane purification processes for use on mine methane are the technical capability of the process to remove impurities so that the product gas is of pipeline quality, the economics of purchasing and operating the process and the suitability of the plant for operation under the conditions at Australian mines. As reviewed in Section 3, a wide range of methane purification technologies is available, including pressure swing adsorption, cryogenic, amine scrubbing and membrane separation. These techniques vary in suitability depending on gas production rates and concentrations. The pressure swing adsorption appears to be more suitable for purifying the coal mine methane than the others.

A schematic of a PSA process for gas purification is shown in Fig. 7. In this process the raw gas is compressed in two stages with scrubbing occurring at the intermediate pressure; the first stage compression is essentially a blower that is used to force the gas through the scrubbing equipment. No catalytic oxygen removal stage is required as the adsorbent specified is effective at removing oxygen, as well as nitrogen, carbon dioxide and hydrogen sulfide. The gas is processed through two stages of adsorption in this case, however the number of stages required will vary with the feed gas quality and the size of adsorption vessel determined as optimal. When the adsorbent in a vessel is exhausted, feed to the vessel is stopped and the vessel depressurised so that the adsorbent releases the adsorbed gases to a waste stream. The waste gas will contain a mixture of gases, including some methane. Where possible, the waste gas from the process is collected and used as fuel for a gas turbine that supplies power to operate the plant. To use a reasonably standard gas turbine, this requires that the waste gas methane concentration be over 30%. Surplus low concentration gas would be flared, or vented if not suitable to combust. If the waste gas from a vessel has higher methane content than the clean feed gas, it is recompressed and recycled through the adsorption process to improve the performance of the plant. Due to the batching arrangement required, it is necessary to have a minimum of three vessels in parallel for each stage of adsorption so that the plant can operate continuously.

Analysis of the process options for pressure swing adsorption of the combined pre- and post-drainage gas streams was performed using a commercial process simulation package, HYSYS.Process [48]. The characteristics of the commercially available Molecular Gate adsorbent for nitrogen removal were used to develop the pressure swing

[2] Carbon credits (AU\$/t $CO_{2\text{-e}}$) are determined based on: (1) AU\$5 ~ 10/t $CO_{2\text{-e}}$ from 'ACARP report C8002: Greenhouse abatement strategy for the coal mining industry [46]'; (2) US\$4 ~ 6/t $CO_{2\text{-e}}$ from 'State and trends of the carbon market 2003, PCF *plus* Research, World Bank [47]'; (3) US\$4 ~ 6/t $CO_{2\text{-e}}$ from 'Greenhouse gas trading increases in 2003, Energy Star Server [energystar@optimuscorp.com], 06/02/2004'.

modules in the simulation software to calculate representative plant size data for the economic analysis. This includes the ancillary plant which is required for treating the gas before processing, namely a blower and scrubber. For the drainage gas flow and composition data, a plant with only two stages of pressure swing adsorption is required to purify the gas to greater than 95% methane content and no residual oxygen or sulfur species. The peak flow in the case study requires that the plant be installed in two trains, as the standard size adsorption units are not capable of processing the full flow. This adds to the flexibility of the plant, as maintenance can be carried out on one train during low gas flow periods without overall loss of availability. In general, 86.80% of the mine drainage gas methane would be used to produce natural gas at a rate of 1,522,970 GJ per year, with a further 8.20% being mitigated and utilised during electricity production for internal plant use and the remainder vented in low concentration waste gas.

5.3.1.2. Economic analysis. The process modelling output was used to estimate the costs of individual plant components and a summary of these costs is given in Table 9. For the purpose of this study, it is considered that two completely independent trains are installed, however some cost reduction should be possible if larger plant items are installed for the initial gas cleaning and turbine plants rather than two smaller items. The total capital cost of the plant is estimated to be approximately AU$9 million, with installation adding an additional 10% to the cost. Operating costs, including labour and maintenance, are estimated to be AU$1.440 million per year. The plant design provides electricity generation through combustion of the waste gases and is specified to be neither a net importer nor exporter of electricity.

The costing data for the process design were incorporated in an economic model with estimates of the operating and maintenance costs. The base conditions for the model were as given previously and a summary of the economic indicators for the plant is given in Table 10. The rate of return on the plant is very high, mostly because it is assumed that the gas can be sold for $5/GJ to a distributor (the current retail price is $10/GJ for large industrial consumers). Obviously, the sale price will depend on contract negotiations and the location of the mine relative to pipelines. If an industrial consumer can be located near the mine, the return on investment could be improved through direct sales.

Table 9
Major capital costs of the pressure swing adsorption process plant

Major equipment	Per train (two trains required)	Total
Scrubber	$130,180	$260,359
Cooler	$16,568	$33,137
Blower	$94,676	$189,352
First vompressor	$150,298	$300,596
Second compressor	$74,415	$148,829
First pressure swing adsorber	$1,968,257	$3,936,515
Second pressure swing adsorber	$1,709,230	$3,418,460
Turbine set	$275,203	$550,406
Instrumentation and control	$80,000	$160,000
Total installed cost	$4,498,827	$8,997,654

Table 10
Results of the preliminary economic analysis of the pressure swing adsorption purification plant

	$0/t $CO_{2\text{-e}}$	$5/t $CO_{2\text{-e}}$	$10/t $CO_{2\text{-e}}$
Production (GJ/yr)	1,522,970	1,522,970	1,522,970
Capital cost ($)	8,997,654	8,997,654	8,997,654
Net present value ($)	55,474,251	89,737,671	124,849,915
Internal rate of return (%)	59.3	90.3	122.1
Break-even natural gas price ($/GJ)	1.78	−0.29	−2.35

5.3.2. Internal combustion gas engines

In this section, a technical and economic analysis is carried out on the internal combustion gas engines with the spark-ignition, which are commercially available. The homogenous charge compression ignition gas engines are still under development and promise to utilise a much lower concentration methane drainage gas.

In power generation, gas engines generally drive synchronous generators at constant speed to produce steady alternating current (AC) power. At reduced loads, the heat rate of spark-ignition engines increases and efficiency decreases. It has been reported by Caterpillar and Energy Nexus Group [16] that, for a typical lean-burn gas engines, the efficiency at 50% load is approximately 8–10% less than full-load efficiency. Conventional gas turbines typically experience efficiency decrease of 15–25% at half-load conditions. Therefore, multiple gas engines/turbines may be preferable to a single large unit to avoid efficiency penalties when significant load reductions are expected on a regular basis which is directly related to mine methane supply continuity affected by mining process variations [16].

5.3.2.1. Potential and operating status. As discussed in Section 3.2.1, a minimum methane concentration of 40% is required for the operation of spark-ignition gas engines. So, this is one of the constraints for determining the potential of gas engine power generation plant at the QLD mine. Other constraints include:

(1) The availability of the plant operation is at least 95%,
(2) The effect of methane concentration variations in mine ventilation air on the plant operation when the ventilation air is used as combustion air for the gas engines.

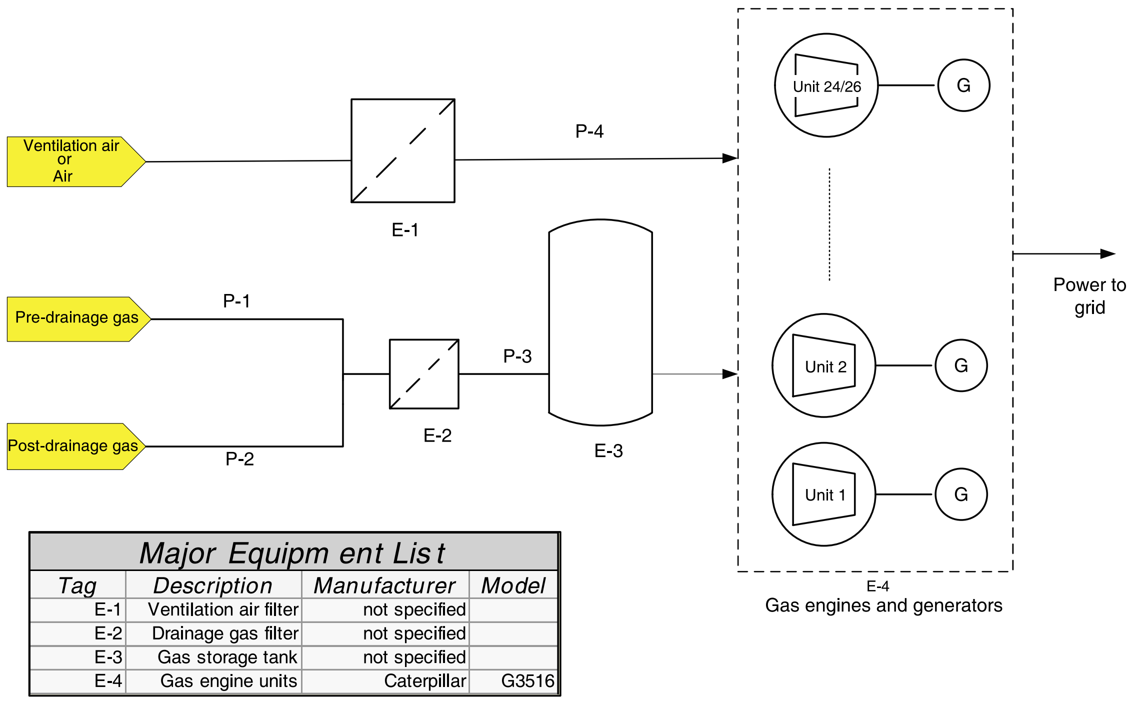
In order to conduct a realistic determination of the potential with the consideration of the mine methane supply continuity, and then economic assessment, 1 MW_e Caterpillar G3516 spark-ignition gas engines, which are commercially available, and have been demonstrated at Appin Colliery, were chosen for the application at the QLD mine. Fig. 8 is a conceptual design of G3516 gas engine power generation plant at the QLD mine, and this figure summarises the major equipment requirements for the plant. The major operating parameters of the G3516 gas engine, based on the manufacturer's technical specifications [49,50], summarised below:

- Power output: 1000 kW_e,
- Thermal input: 2.96 MW_t,
- Fuel consumption at 100% load: 10.67 MJ/kW h,
- Efficiency at 100% load: 33.74%,
- Fuel feed rate: 0.0823 m^3/s (pure CH_4), and
- Air flow rate: 1.362 m^3/s.

In addition, the efficiencies of the gas engine at 100, 75 and 50% loads are 33.74, 32.6 and 31%, respectively.

Based on the methane emission data summarised in Fig. 6, it can be determined that from 10th January to 24th November 2002 (319 days), probabilities of the methane concentration being greater than 40 are 99.6 and 99.2% for the pre-drainage gas and post-drainage gas, respectively. The potential size of the gas engine power plant consuming both the pre- and post-drainage gas is dependant on the drainage gas supply that allows the gas engines run with the minimum load of 50% and the availability of over 95%. It is also valuable to explore the potential of installing more gas engine units when the ventilation air is used as the combustion air, as it contains some methane and results in an increase in the thermal input of the plant. Hence, as shown in Fig. 9, the potential sizes of the gas engine power plant were determined and are summarised below:

- *Gas engine power plant A*. When ambient air is used as combustion air, 24×1 MW_e Caterpillar G3516 spark-ignition gas engines can be installed at the QLD mine. During the 319 days, the gas engine plant can be operated at the full load over 72% of the period, 75–99% load over 21% of the period, and 50–74% load over 6.4% of the period. 52,470,469 m^3 methane (out of total 58,018,603 m^3 drainage gas methane), i.e. 90.4% of drainage gas, can be utilised to generate electricity of 176,439 MWh.
- *Gas engine power plant B*. When the mine ventilation air is used as combustion air, we still install the above 24 gas engine units at the QLD mine, but their thermal input should be increased due to some methane in the ventilation air enters into the gas engines. Hence, the output of the plant should be higher. During the 319 days, the gas engine plant can



Major Equipm ent Lis t			
Tag	Description	Manufacturer	Model
E-1	Ventilation air filter	not specified	
E-2	Drainage gas filter	not specified	
E-3	Gas storage tank	not specified	
E-4	Gas engine units	Caterpillar	G3516

Fig. 8. Diagram of internal combustion gas engine power generation system at the QLD mine.

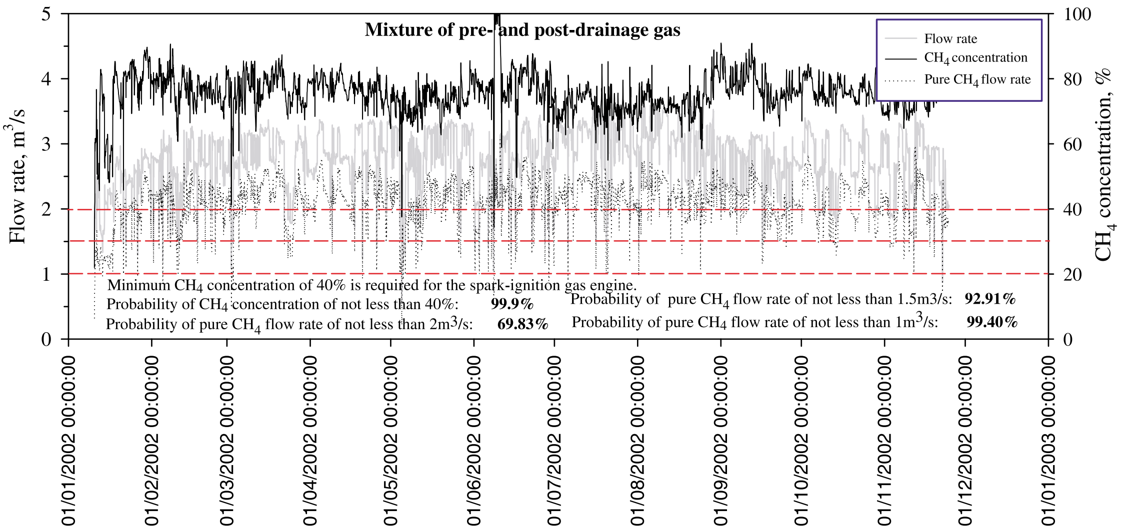


Fig. 9. Potential of the gas engine power generation plant at the QLD mine.

be operated at the full load over 82.8% of the period, 75–99% load over 12.8% of the period, and 50–74% load over 4.1% of the period. A total of 48,563,246 m^3 methane (out of total 58,018,603 m^3 drainage gas methane), i.e. 83.7% of drainage gas, and 4,926,753 m^3 methane (out of 28,200,149 m^3 ventilation air methane), i.e. 17.5% of the ventilation air methane, can be utilised to generate electricity of 180,276 MW h. The total amount of methane used in the gas engine plant is 53,489,999 m^3. It is obvious that extra electricity of 3837 MW h is generated by using extra 1,019,530 m^3 methane (combined methane from drainage gas and ventilation air) when the ventilation air is used compared with using the ambient air although the ventilation air methane only contributes 7.7% of the total amount of methane to the gas engines.

– *Gas engine power plant C*. When the mine ventilation air is used as combustion air, 26×1 MW_e Caterpillar G3516 spark-ignition gas engines are installed at the QLD mine. During the 319 days, the gas engine plant can be operated at full load over 76.2% of the period, 75–99% load over 17.8% of the period, and 50–74% load over 5.5% of the period. 51,277,749 m^3 methane (out of total 58,018,603 m^3 drainage gas methane), i.e. 88.4% of drainage gas, and 5,276,082 m^3 methane (out of 28,200,149 m^3 ventilation air methane), i.e. 18.7% of the ventilation air methane, can be utilised to generate electricity of 190,324 MW h. The total amount of methane used in the gas engine plant is 56,553,831 m^3. It is obvious that extra electricity of 13,885 MW h is generated by using an extra 4,083,361 m^3 methane (combined methane from drainage gas and ventilation air) when the ventilation air is used compared with the gas engine power plant A.

Fig. 10 shows how the gas engine power generation plants operate at the QLD mine. Although, when the drainage gas supply rate reduces, it is possible to turn off one or more of the 24/26 gas engines to maintain operation of the remaining engines at full load, this has not been considered in generating the figure. This is due to the gas engine efficiency reduction from 33.7 to 31% when the load is reduced from the full-load to 50% load not being overly significant. Fig. 10 shows variations in gas engine load and pure methane feed rate, which is constrained by the mine drainage gas supply, during the operation of the gas engine plant from 10th January to 24th November 2002. Calculations indicate that 17.5–18.7% of the ventilation air methane can be mitigated when the ventilation air is used as the combustion air for the gas engines.

5.3.2.2. Economic analysis. Based on the system diagram of gas engine power plant in Fig. 8 and the operating parameters determined above, a preliminary economic analysis was used to determine the economic feasibility of the applications of the gas engine power plant option C at the QLD mine.

At the QLD mine, it was determined that 26 one-megawatt Caterpillar G3516 gas engine units are required for the gas engine power plant, and the operating and maintenance costs are estimated to be AU$2.37 million per year. Table 11 summarises the major capital costs of the gas engine power plant. Table 12 summarises the results of this preliminary economic analysis for the gas engine power plant at the QLD mine. The results shown in Table 12 indicate that the application of the gas engine power plant at the QLD mine is economically feasible. As a basic case with no carbon credit, the break-even price of generating electricity is $24.2/MW h, and the internal rate of return is 17.7%. The best case is that when the carbon credit of $10/t

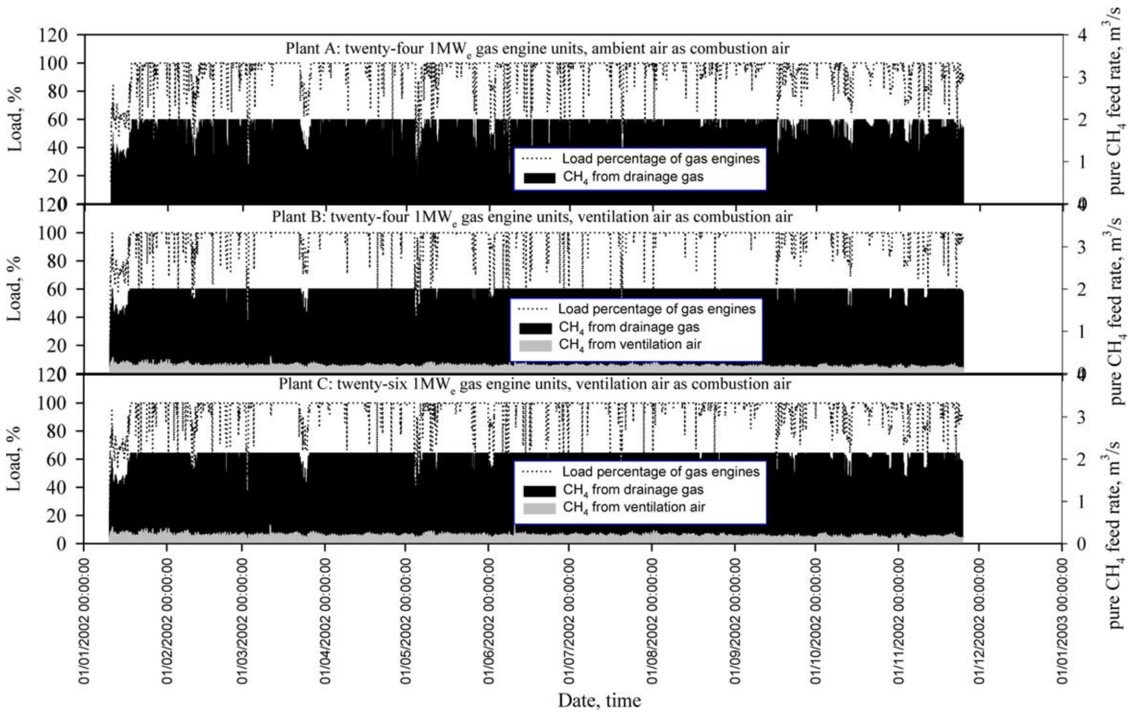


Fig. 10. Operating state of the gas engine power plant at the QLD mine.

$CO_{2\text{-e}}$ is considered, the internal rate of return is 48.4%, and the break-even price of generating electricity is negative \$18.8/MW h due to the profit from the carbon trading.

5.3.3. Conventional gas turbines

5.3.3.1. Potential and operating status. As discussed in Section 3.2.2, it is feasible to establish a stable flame when the heating value of the drainage gas is greater than approximately 10 MJ/m^3, which is equal to approximately 30% methane. As analysed in Section 5.3.2.1, the probability of the methane concentration being greater than 40% is over 99.2%. It was determined that the probability of methane concentration greater than 30% is 99.99% for the mixture of pre- and post-drainage gas. Therefore, theoretically and practically there should be no difficulties in establishing a stable combustion process. However, a minimum heating value of 31.5 MJ/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 that are likely to be used in this type of application. Hence, certain modifications to the gas turbine combustors are required when the methane concentration is less than 87.5%. At the QLD mine, the average methane concentration of the mixture of pre- and post-drainage gas is 75.6%, and

Table 11
Major capital costs of the gas engine power plant

Major equipment	Unit price
Gas engine unit[a], 1000 kW	\$1,000,000
Fan for ventilation air	\$4500
Ventilation air filter	\$190,000
Fan for drainage gas	\$50,000
Drainage gas filter	\$150,000
Pipeline for drainage gas	\$200,000
Drainage gas storage	\$50,000

[a] The unit price of Caterpillar G3516 gas engine is estimated to be about \$1 million in the Australian market.

Table 12
Results of the preliminary economic analysis for the gas engine power plant

	\$0/t $CO_{2\text{-e}}$	\$5/t $CO_{2\text{-e}}$	\$10/t $CO_{2\text{-e}}$
Plant size (MW$_e$)	26	26	26
Capital cost (\$)	29,308,950	29,308,950	29,308,950
Capital cost (\$/kW$_e$)	1,127	1,127	1,127
Net present value[a] (\$)	29,610,749	79,168,399	128,726,049
Internal rate of return[a] (%)	17.7	33.2	48.4
Break-even price of electricity[b] (\$/MW h)	24.2	2.7	−18.8

[a] Determined based on the discount rate: 7.5%, electricity price: \$37/MW h.

[b] Determined based on the discount rate: 7.5%, the internal rate of return: 7.5%, and the net present value: 0.

the probability of methane concentration from 30 to 70% is 13%. In the following analysis, 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.

The constraints for determining the potential of gas turbine power generation plant at the QLD mine are a minimum methane concentration of 30% and that the availability of the plant operation will be 95%. For the gas turbines, the ventilation air is not considered as combustion air because the gas turbines use a significant fraction of the combustion air for dilution and cooling processes, which results in a significant amount of methane in the ventilation air passing through the gas turbine systems without oxidation. An alternative is to increase the complexity of the gas turbine systems by using a second compressor, but this would require significant additional cost. In general, to conduct a realistic determination of the potential with the consideration of the mine methane supply continuity, and then economic assessment, the modified 3.37 MW_e Solar Turbine CENTAUR 40 was chosen for the application at the QLD mine. Fig. 11 is a conceptual design of CENTAUR gas turbine power generation plant at the QLD mine, and this figure also summarises the major equipment requirements for the plant.

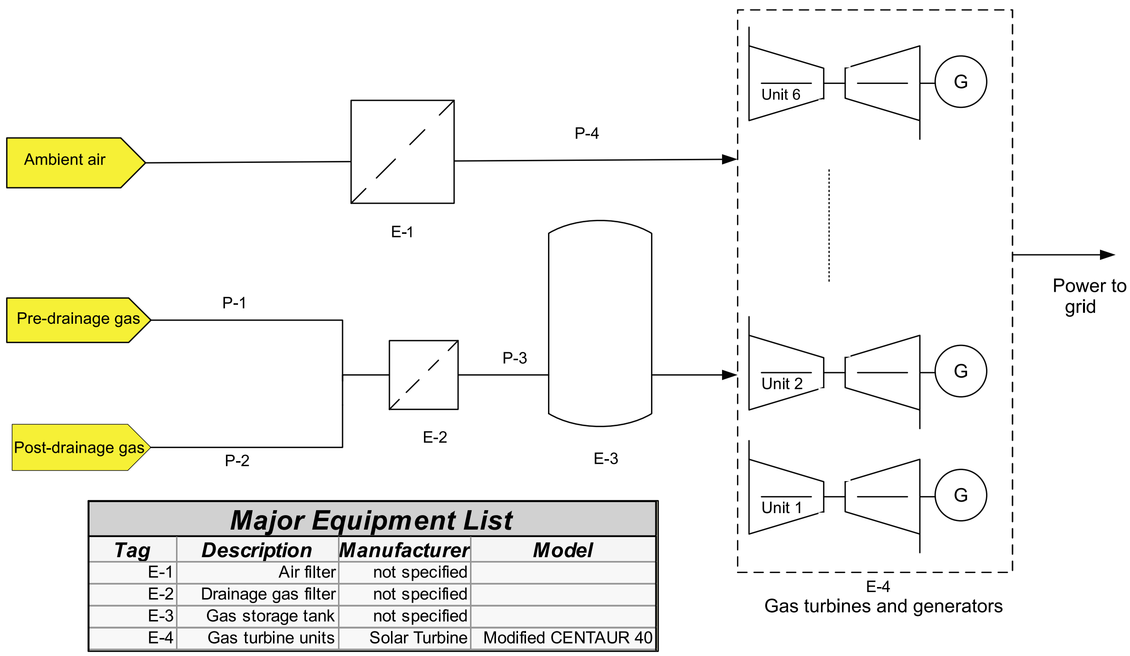
Based on the technical specifications of the Solar Gas Turbine CENTAUR 40 [51], its output power is 3.515 MW_e at 15 °C and sea level. However, temperature of the inlet air has a significant effect on the turbine efficiency, and the case study has the gas turbines being installed at the QLD mine, which is located in Central Queensland. Therefore, a more realistic average temperature of ambient air is 20 °C. Then, based on the performance characteristics of the gas turbine [51], the major operating parameters under this condition are determined and summarised below:

- Power output: 3370 kW_e,
- Thermal input: 12.1 MW_t,
- Fuel consumption at 100% load: 12.93 MJ/kW h,
- Efficiency at 100% load: 27.85%,
- Fuel feed rate: 0.336 m^3/s (pure CH_4), and
- Air flow rate: $\sim$14.4 m^3/s.

In addition, the efficiencies of the gas turbine at 100, 75 and 50% loads are stated to be 27.85, 25.79 and 21.60%, respectively.

Based on real methane emission data summarised in Fig. 6, the potential size of a gas turbine power plant consuming both the pre- and post-drainage gas, and the plant size is dependant on the drainage gas supply continuity which allows the gas turbines run with the minimum load of 50% and the availability of over 95%. Hence, as shown in Fig. 12 the potential size of the gas turbine plant is determined and summarised below:

- 6×3.37 MW_e CENTAUR 40 gas turbines can be installed at the QLD mine.
- When ambient air is used as combustion air, during the 319 days the gas turbine plant can be operated at the full load over 70% of the period, 75–99% load over 22.6% of



Tag	Description	Manufacturer	Model
E-1	Air filter	not specified	
E-2	Drainage gas filter	not specified	
E-3	Gas storage tank	not specified	
E-4	Gas turbine units	Solar Turbine	Modified CENTAUR 40

Fig. 11. Diagram of CENTAUR 40 gas turbine power generation system at the QLD mine.

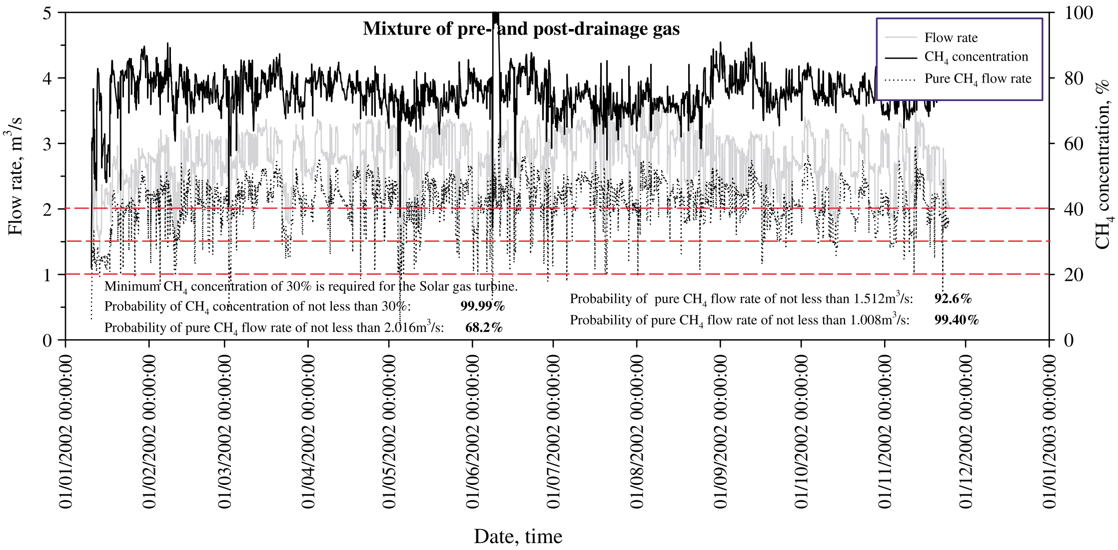


Fig. 12. Potential of the conventional gas turbine power generation plant at the QLD mine.

the period, and 50–74% load over 6.8% of the period. A total of 52,774,177 m^3 methane (out of total 58,018,603 m^3 drainage methane), i.e. 91% of drainage gas, can be utilised to generate electricity of 146,446 MW h.

Fig. 13 shows how the conventional gas turbine power generation plant operates at the QLD mine. Similar to the gas engine plant discussed above, when the drainage gas supply rate reduces, it is possible to turn off one or more of the six gas turbines to maintain the others at full-load operation. This scenario was not considered in Fig. 13 due to the increased complexity of representing process operations, despite the gas turbine efficiency is obviously reduced from 27.85 to 21.6% when the load is reduced from the full-load to 50% load. Fig. 13 shows variations of gas turbine load and pure CH_4 feed rate, due to inconsistencies in the mine drainage gas supply, during the operation of gas turbine plant from 10th January to 24th November 2002.

5.3.3.2. Economic analysis. Based on the system diagram of conventional gas turbine power plant in Fig. 11 and the operating parameters determined above, a preliminary economic analysis was conducted to determine the economic feasibility of the application of the gas turbine power plant at the QLD mine.

At the QLD mine, it was determined that six modified CENTAUR 40 (3.37 MW_e) gas turbine units would be required, and the operating and maintenance costs are estimated to be AU$1.52 million per year. Table 13 summarises the major capital costs of the gas turbine power plant. Table 14 summarises the results of a preliminary economic analysis of the gas turbine power plant at the QLD mine. The results show that the application of the gas turbine power plant at the QLD mine is economically feasible, and offers higher rates of return than the gas engine power plant in terms of the internal rate of return. As a basic case with no carbon credit, the break-even price of generating electricity is $17.5/MW h, and

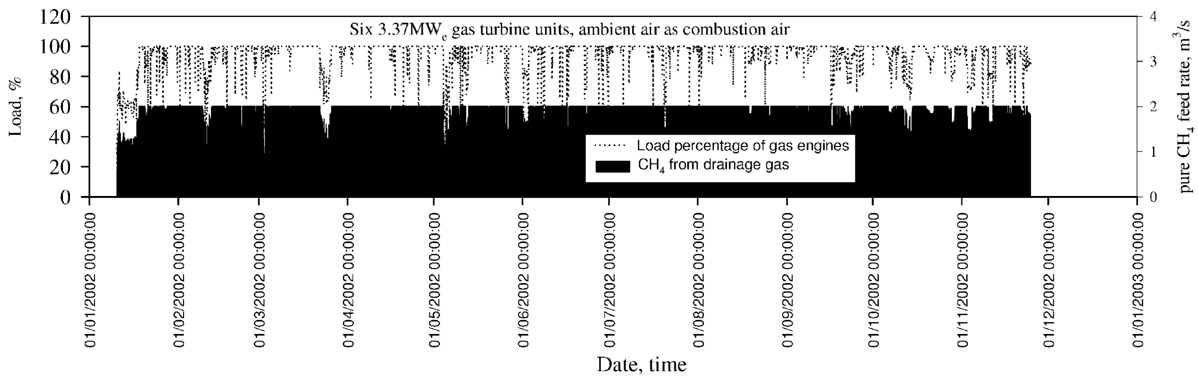


Fig. 13. Operating state of the conventional gas turbine power plant at the QLD mine.

Table 13
Major capital costs of the gas turbine power plant

Major equipment	Unit price
Gas turbine unit[a], 3370 kW	$2,060,000
Air filter	$20,000
Fan for drainage gas	$60,000
Drainage gas filter	$180,000
Pipeline for drainage gas	$220,000
Drainage gas storage	$55,000

[a] The unit price of CENTAUR 40 gas turbine is estimated based on current gas turbine market.

Table 14
Results of the preliminary economic analysis for the gas turbine power plant

	\$0/t $CO_{2\text{-e}}$	\$5/t $CO_{2\text{-e}}$	\$10/t $CO_{2\text{-e}}$
Plant size (MW_e)	20.2	20.2	20.2
Capital cost (\$)	14,157,000	14,157,000	14,157,000
Capital cost (\$/kW_e)	700	700	700
Net present value (\$)	34,541,228	80,786,798	133,656,528
Internal rate of return (%)	30.8	60.2	93.7
Break-even price of electricity (\$/MW h)	17.5	−8.5	−38.3

the internal rate of return is 30.8%. The best case is that when the carbon credit of \$10/t $CO_{2\text{-e}}$ is considered, the internal rate of return is 93.7%, and the cost of generating electricity is negative \$38.3/MW h mainly due to the profit from carbon trading.

5.4. Potential technologies for ventilation air methane mitigation and utilisation

5.4.1. TFFR, CFRR and CMR

5.4.1.1. Potential and operating status. As reviewed in Table 7, the minimum methane concentrations are 0.2, 0.1 and 0.4% for TFFR, CFRR and CMR operations, respectively. Based on the data in Fig. 6, and as determined in Fig. 14, the probabilities of methane concentration being greater than 0.1, 0.2 and 0.4 are 99.9, 99.8 and 97.2% for the ventilation air, respectively; and also the probability of ventilation air flow of greater than 170 m^3/s is 97.4%. Therefore, it is evident that from 10th January to 24th November 2002 (319 days) that all of these technologies, when applied at the QLD mine, can be run with a feed supply availability of over 95%. Based on the data shown in Fig. 14, for any of the TFFR, CFRR and CMR plants at the QLD mine, approximately 100% of the ventilation air will be used and 28,200,149 m^3 of methane will be mitigated.

However, as discussed in Section 4, the CMR technology uses a recuperator (rather than regenerating heating process of TFFR and CFCC) to preheat ventilation air to the expected temperature by using the flue gas from the monolith catalytic combustor. So, the CMR units need to be run continuously, otherwise there is a need to restart the plant after the methane concentration has dropped to less than 0.4% and the combustor temperature has dropped below 500 °C. The restarting procedure can take up to 8 h from ambient temperatures, so would make the plant unsuitable for mines with low methane concentrations. Therefore, it is likely to be a better option to use additional fuel to keep the combustion process going. During the 319 day operating period, 62,395 m^3 methane would be required as additional fuel for the CMR plant at the QLD mine. Also,

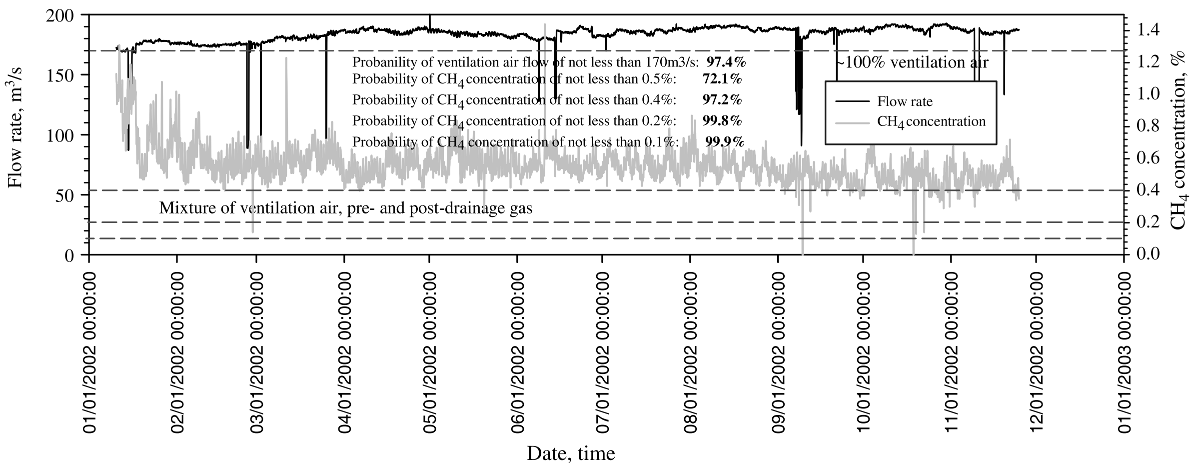


Fig. 14. Potential of TFFR, CFRR and CMR methane mitigation plants at the QLD mine.

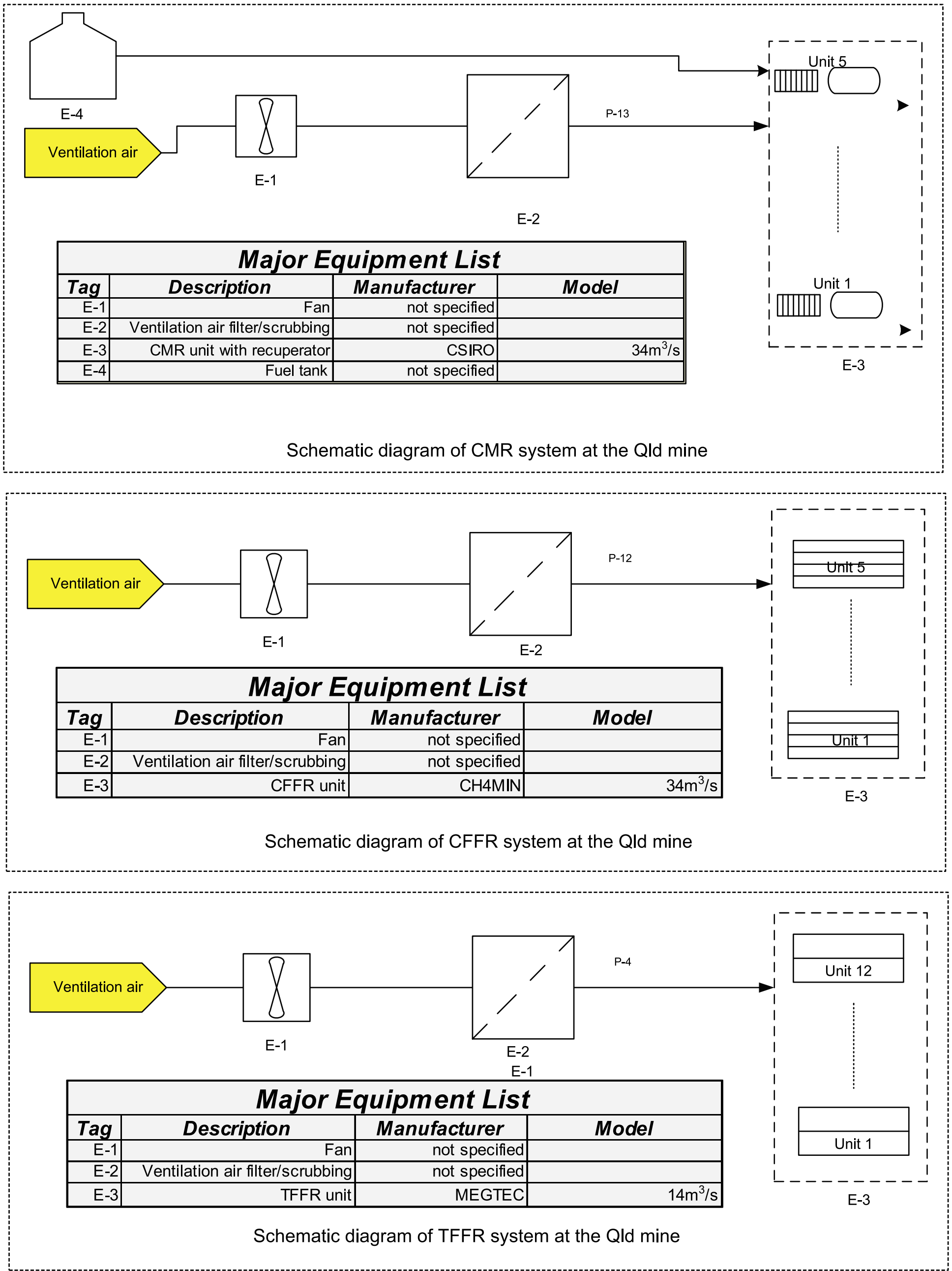


Fig. 15. Diagram of TFFR, CFFR or CMR methane mitigation plant system at the QLD mine.

as discussed in Section 4, the TFFR and CFFR plants can operate with methane concentrations lower than the minimum continuous operating requirement for some period due to thermal inertia. It is difficult to determine accurately what operation is possible before combustion will be extinguished. Therefore, it was assumed that the TFFR and CFFR plants would run continuously for the economic assessment below.

Fig. 15 shows a conceptual design of TFFR, CFFR or CMR methane mitigation plants at the QLD mine. For the TFFR plant, units of the same size as those that are being used by the CONSOL Energy for the demonstration in Pennsylvania were specified. For the CFRR and CMR plants, a total of 5 units each were specified, which are capable of processing 170 m^3/s of ventilation air. Operating states of the TFFR, CFFR or CMR methane mitigation

Table 15
Major capital costs of the TFFR, CFFR or CMR plants

TFFR plant		CFFR plant		CMR plant	
Major equipment	Unit price	Major equipment	Unit price	Major equipment	Unit price
TFFR unit[a], 14 m^3/s	$1,200,000	CFFR unit[b], 34 m^3/s	$1,700,000	CMR unit[c], 34 m^3/s	$1,500,000
Fans for ventilation air	6×$4500	Fans for ventilation air	5×$9,000	Fans for ventilation air	5×$9000
Ventilation air filter/ scrubbers	6×$180,000	Ventilation air filter/ scrubbers	5×$350,000	Ventilation air filter/ scrubbers	5×$350,000
				Fuel tank	$300,000

[a] The unit price of TFFR is estimated based on the costs for two commercial demonstration units by CONSOL Energy [40].
[b] The unit price of CFFR is estimated based on [41].
[c] The unit price of CMR is estimated based on the experimental results of methane catalytic combustion in [19].

plants should be similar to the plots shown in Fig. 14, neglecting the addition of fuel to keep the CMR plant in continuous operation.

5.4.1.2. Economic analysis. Based on the system diagrams of TFFR, CFFR or CMR methane mitigation plants in Fig. 15 and the operating parameters determined previously, a preliminary economic analysis has been performed for the ventilation air methane mitigation plant designs at the QLD mine. The key data for input into the analysis are:

– TFFR plant: 12 TFFR units, and the operating and maintenance costs are estimated to be $1.88 million per year;
– CFFR plant: five CFFR units, and the operating and maintenance costs are estimated to be $1.51 million per year;
– CMR plant: five CMR units (including recuperators), and the operating and maintenance costs are estimated to be $1.46 million per year.

Table 15 summarises the major capital costs of the TFFR, CFFR or CMR plants. In addition, for the CMR plant, the cost of additional fuel is assumed to be $2/GJ as the value of the drainage gas used for this plant. Table 16 summarises the results of this preliminary economic analysis of the TFFR, CFRR and CMR plants at the QLD mine. The results indicate that the implementation of the methane mitigation plants at the QLD mine is not economic without a carbon credit. The methane mitigation technology is likely to be attractive to investors if the carbon credit is $10/t $CO_{2\text{-e}}$ or greater.

5.4.2. Lean-burn gas turbines

As reviewed in Table 8, currently there are three types of lean-burn gas turbines, which are being developed for mitigating and utilising ventilation air methane. The lean-burn gas turbines aim at mitigating and using most of the mine ventilation air methane, but generally cannot utilise all ventilation air without the addition of supplementary fuel. The technologies can be defined on the concentration of methane required, namely 1% methane for the catalytic turbine and 1.6% methane for the recuperative turbine. In the following, the potential, operating status and preliminary economic performance are determined for the implementation of 1 and 1.6% methane lean-burn gas turbines into the QLD mine, respectively.

For these lean-burn gas turbines, load adjustability is significantly different to the conventional gas turbines and the spark-ignition gas engines. This is because the lean-burn gas turbines run on very low concentration methane in air and, if the methane concentration is further decreased for part load, it is likely that combustion will be extinguished due to the lower preheating air temperature. The importance of ignition temperatures has been discussed in Section 4. Therefore, it is expected that the lean-burn gas turbines will only operate at constant load, i.e. close to 100% load. For this almost constant operation at the full load, some drainage gas is required to be injected into ventilation air to maintain almost constant methane concentration in the air. In order to utilise the remaining drainage gas for power generation in this analysis the G3516 spark-ignition gas engines, for

Table 16
Results of the preliminary economic analysis for the TFFR, CFFR and CMR plants

	TFFR plant	CFFR plant	CMR plant
Plant size (m^3/s)	170	170	170
Capital cost ($)	17,057,700	11,324,500	10,554,500
$0/t $CO_{2\text{-}e}$			
Net present value ($)	−38,033,064	−28,106,116	−26,859,631
Internal rate of return (%)	N/A	N/A	N/A
$5/t $CO_{2\text{-}e}$			
Net present value ($)	−13,321,509	−3,394,560	−2,148,076
Internal rate of return (%)	N/A	3.8	5.1
$10/t $CO_{2\text{-}e}$			
Net present value ($)	11,390,046	21,316,995	22,563,479
Internal rate of return (%)	14.4	25.8	28.1

example, could be chosen as supplementary plant. The combined technologies for both drainage gas and ventilation air methane utilisation will be discussed in Section 5.5. The technical and economic assessment in this section will be carried out only for lean-burn gas turbine power plants:

- 1% methane catalytic combustion gas turbine power plant,
- 1.6% methane recuperative combustion gas turbine power plant.

5.4.2.1. Potential and operating status. Determining the optimum size of a gas turbine plant at a mine requires analysis of mine data, particularly gas supply continuity, to make sure that the plant can be continuously operated for long periods with at least 95% overall availability. Otherwise, additional fuel will be needed for the operation, and this may not be a feasible option due to the cost of the fuel. Fig. 16 shows the probabilities of CH_4 concentrations in the mixtures of the drainage gas and different percentages of ventilation air at the QLD mine. Based on the data shown in this figure, the potential sizes of 1 and 1.6% methane turbine plants for the QLD mine are determined and summarised below.

- For the 1% methane turbine plant: over 92% ventilation air is utilised, and the working fluid rate is approximately 170 m^3/s, and the thermal input of the plant is around 61 MW_t, and the output is about 12 MW_e assuming the generation efficiency is 20%. During the 319 days, the 1% methane lean-burn gas turbine plant can be operated at the full load over 99.80% of the period. A total of 25,953,753 m^3 methane (out of 28,200,149 m^3 ventilation air methane), i.e. 92% of the ventilation air methane, and 20,809,167 m^3 methane (out of total 58,018,603 m^3 drainage gas methane), i.e. 35.9% of drainage gas, can be used to generate electricity of 93,514 MW h. The total amount of methane used in the 1% methane lean-burn gas turbine plant is 46,762,920 m^3.
- For the 1.6% methane turbine plant: only about 45% ventilation air methane is utilised, and the working fluid rate is approximately 85 m^3/s, and the thermal input of the plant is around 49 MW_t, and the output is about 9.5 MW_e assuming the generation efficiency is 20%. During the 319 days the 1.6% methane lean-burn gas turbine plant can be operated at the full load over 99.50% of the period. A total of 12,608,997 m^3 methane (out of 28,200,149 m^3 ventilation air methane), i.e. 44.7% of the ventilation air methane, and 24,801,339 m^3 methane (out of total 58,018,603 m^3 drainage gas methane), i.e. 42.7% of drainage gas, can be used to generate electricity of 74,821 MW h. The total amount of methane used in the 1.6% methane lean-burn gas turbine plant is 37,410,336 m^3.

Fig. 17 is a conceptual design of a 1% methane lean-burn catalytic gas turbine or a 1.6% methane recuperative gas turbine power generation plant at the QLD mine. Fig. 18 shows how the lean-burn gas turbine power generation plants operate at the QLD mine. For the 1% methane turbine plant, four 15 MW_t units could be installed with the total power output of approximately 12 MW_e. However, it is obvious that the requirement for more methane from drainage gas for the 1.6% methane plant limits its plant size to an output of approximately 9.5 MW_e, and only three 16 MW_t units could be installed.

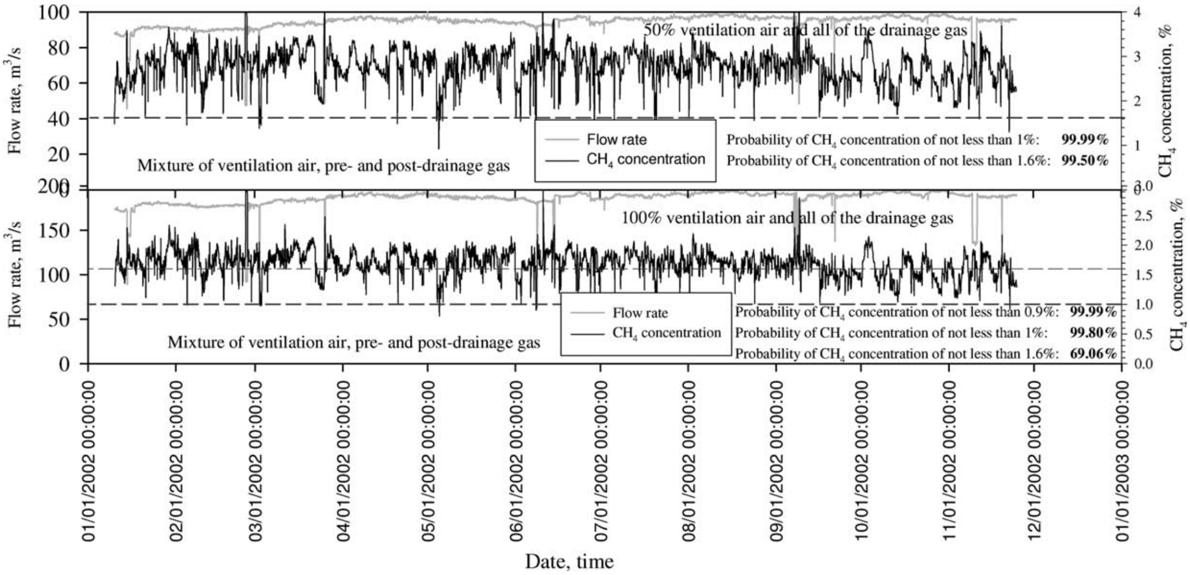


Fig. 16. Potential of 1 or 1.6% methane lean-burn turbine plants at the QLD mine.

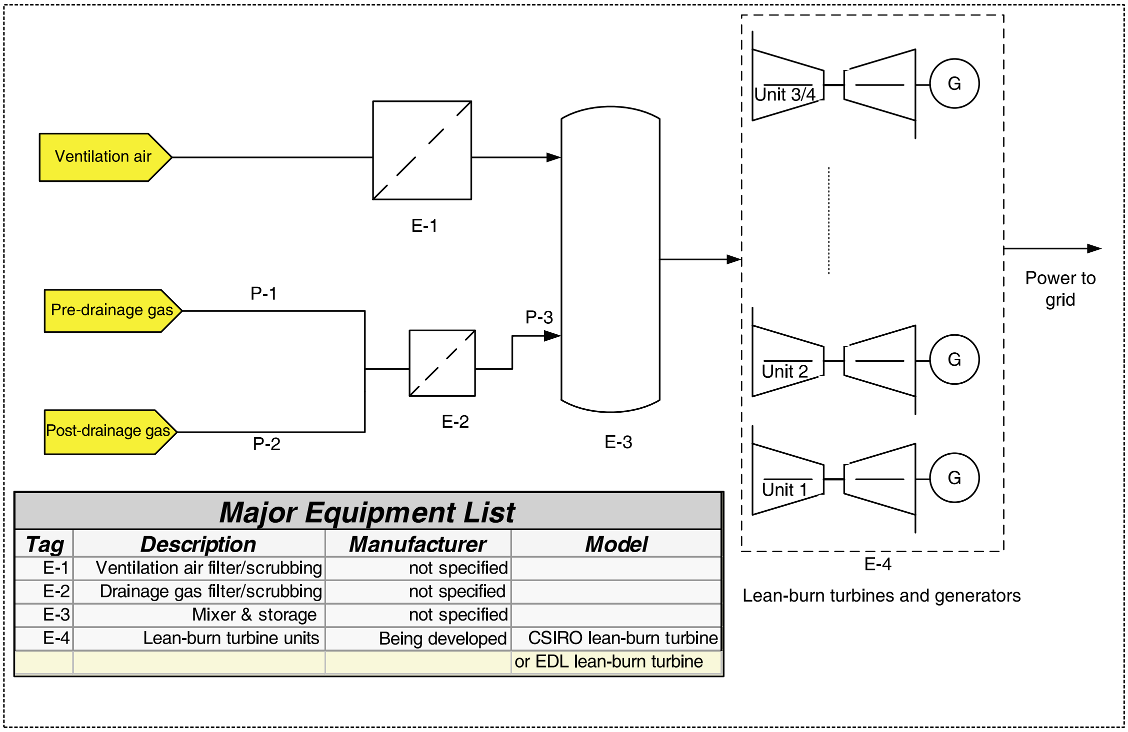


Fig. 17. Diagram of CSIRO or EDL lean-burn gas turbine plant at the QLD mine.

5.4.2.2. Economic analysis. Based on the system diagram of lean-burn gas turbine plants in Fig. 17 and the operating parameters determined, a preliminary economic analysis was conducted to determine the economic feasibility of the applications of the 1 and 1.6% methane turbine plants into the QLD mine. It was summarised as follows:

- 1% methane power plant: four 3 MW_e units, and the operating and maintenance costs are estimated to be \$1.58 million per year;
- 1.6% methane power plant: three 3 MW_e units, and the operating and maintenance costs are estimated to be \$1.21 million per year.

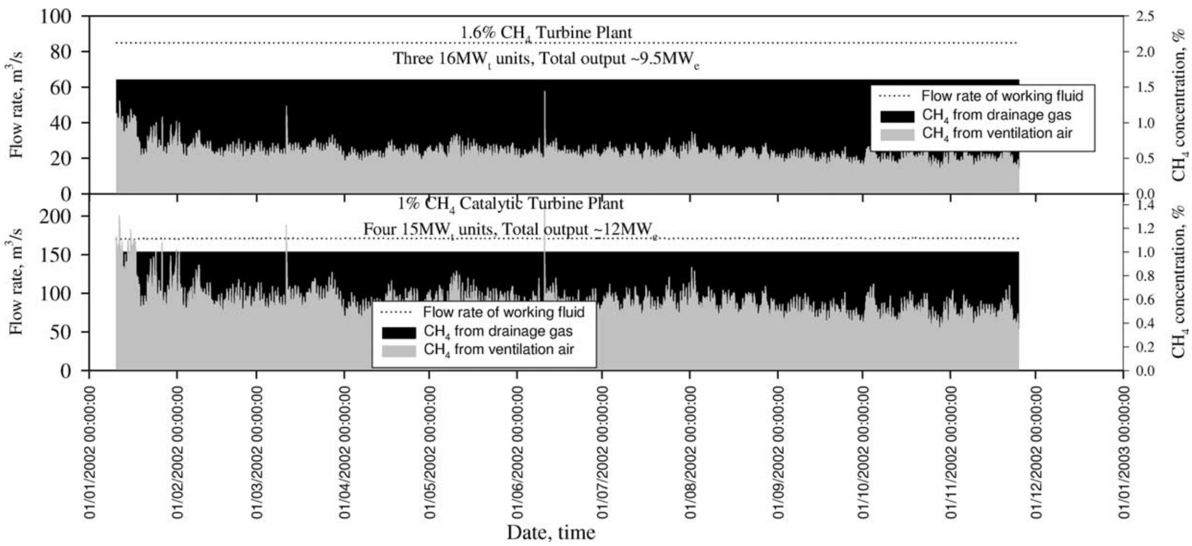


Fig. 18. Operating states of the 1 and 1.6% methane turbine plants at the QLD mine.

Table 17
Major capital costs of the 1 or 1.6% CH_4 turbine power plants

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], 3000 kW	$2,606,000	1.6% CH_4 recuperative turbine unit[a], 3167 kW	$ 2,714,000
Fans for ventilation air	$14,000	Fans for ventilation air	$9000
Filter/scrubbers for ventilation air	$800,000	Filter/scrubbers for ventilation air	$450,000
Fan for drainage gas	$20,000	Fan for drainage gas	$22,000
Filter/scrubber for drainage gas	$100,000	Filter/scrubber for drainage gas	$120,000
Pipeline for drainage gas	$200,000	Pipeline for drainage gas	$200,000
Mixer/storage	$200,000	Mixer/storage	$150,000

[a] The unit prices of the lean-burn turbines are 'best' estimates in the absence of reliable data.

Table 17 summarises the major capital costs of the 1% turbine plant and 1.6% turbine plant. Table 18 summarises the results of preliminary economic analysis of the 1 or 1.6% methane turbine applications at the QLD mine under difference conditions. The results indicate that the applications of the two lean-burn gas turbine plants at the QLD mine are financially viable. As a basic case with no carbon credit, the break-even price of generating electricity is $27.0/MW h, and the internal rate of return is 16.5% when the 1% methane turbine plant is installed at the QLD mine; and the internal rate of return is 17.7% for the 1.6% methane turbine plant. However, the 1% methane turbine plant has a higher throughput, utilises more ventilation air methane and needs less drainage gas for the operation compared with the 1.6% methane plant. Hence, when the scenario for economic assessment is changed, such as paying for the drainage gas, and no carbon credit for drainage gas methane, the results will be very different. This has been studied [20] and the 1% methane turbine shows much better economic performance. If carbon credits are available, there can be significantly higher returns from plant operations.

5.5. Combined technologies for both drainage gas and ventilation air methane

In order to utilise the remaining drainage gas when using a lean-burn gas turbine power plant, it is likely that a supplementary plant, such as G3516 spark-ignition gas engines, could be used in combination. Therefore, it could be much more valuable to have combined technologies to maximise mitigation and utilisation of methane from both drainage gas and ventilation air. Based on the assessments of the gas engines, conventional gas turbines and the lean-burn gas turbines, the following combined technologies are determined for both drainage gas and ventilation air methane utilisation:

– 1% methane catalytic combustion gas turbine and G3516 gas engine power plant,
– 1.6% methane recuperative combustion gas turbine and G3516 gas engine power plant.

5.5.1. 1% methane turbine and gas engine power plant

5.5.1.1. Potential and operating status. The potential and operating status of the 1% methane lean-burn gas turbine power plant at the QLD mine has been determined, so it is possible to determine the potential and operating status of the gas engines using the remaining drainage gas and the characteristics of the combined 1% methane turbine and gas engine plant at the QLD mine. The technical specifications and major operating parameters of the 1 MW_e G3516 gas engine were summarised in Section 5.3.2. The 1% methane turbine plant will use over 92% ventilation air from the QLD mine. So there is insufficient ventilation air for the gas engines, and ambient air will be used for the combustion process.

Based on the data of the remaining drainage gas from the 1% methane turbine plant, as shown in Fig. 19, the potential sizes of the gas engine power plant were determined.

Table 18
Results of the preliminary economic analysis for the lean-burn turbine plants

	1% CH_4 plant	1.6% CH_4 plant
Plant size (MW_e)	12	9.5
Capital cost ($)	12,933,800	10,002,300
Capital cost ($/k$W_e$)	1078	1053
$0/t $CO_{2\text{-}e}$		
Net present value ($)	11,323,905	10,099,074
Internal rate of return (%)	16.5	17.7
Break-even price of electricity ($/MW h)	27.0	25.9
$5/t $CO_{2\text{-}e}$		
Net present value ($)	52,301,862	52,883,739
Internal rate of return (%)	45.2	47.4
Break-even price of electricity ($/MW h)	−9.2	−10.3
$10/t $CO_{2\text{-}e}$		
Net present value ($)	93,279,818	75,663,804
Internal rate of return (%)	73.7	76.8
Break-even price of electricity ($/MW h)	−45.3	−46.5

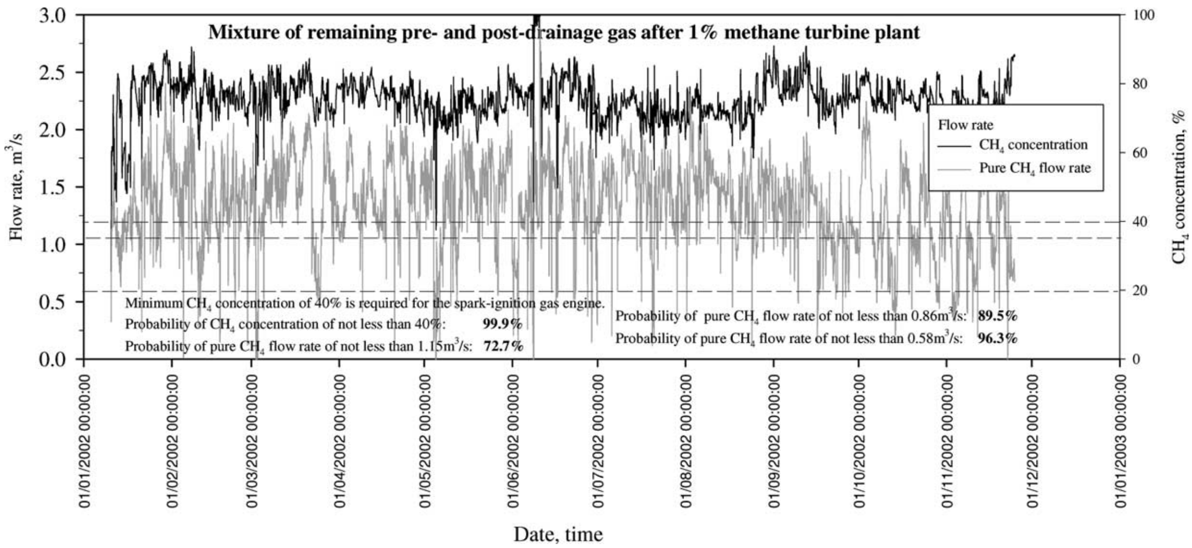


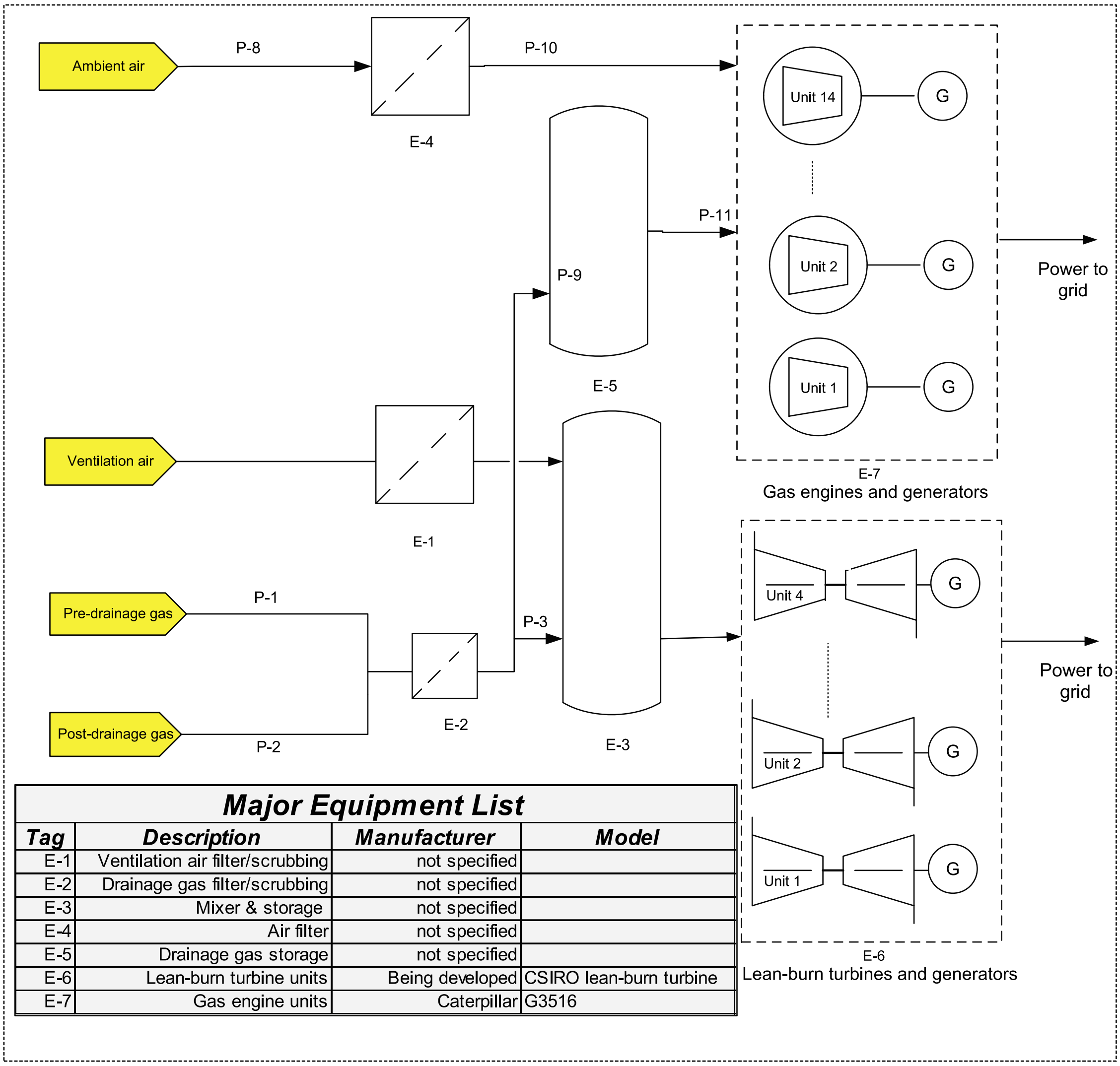
Fig. 19. Potential of the gas engine power generation plant after the 1% methane turbine plant at the QLD mine.

From this figure, it can be determined that from 10th January to 24th November 2002 (319 days), the probability of the methane concentration being greater than 40% is 99.9% for the mixture of remaining pre-drainage gas and post-drainage gas after the 1% methane turbine plant. Therefore, the potential size of the gas engine plant consuming the remaining drainage gas is determined by the remaining drainage gas supply continuity which allows the gas engines run with minimum load of 50% and availability of over 95%. Based on Fig. 19, $14\times1\ MW_e$ Caterpillar G3516 spark-ignition gas engines can be installed at the QLD mine besides the 1% methane turbine plant. During the 319 days, this gas engine plant can be operated at the full load over 73.8% of the period, 75–99% load over 15.7% of the period, and 50–74% load over 6.8% of the period. A total of 37,213,741 m^3 methane (out of total 58,018,603 m^3 drainage gas methane), i.e. 64.1% of drainage gas, can be utilised to generate electricity of 99,402 MW h.

The combined technologies allow for maximum utilisation of drainage gas and ventilation air methane at the QLD mine. Table 19 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

Table 19
Major operating parameters and features of the combined 1% methane turbine and gas engine power plant at the QLD mine

10th January to 24th November 2002 (319 days)			
Type of power generation unit		Combined 1% CH_4 turbine and gas engine plant	
		1% CH_4 turbine	Gas engine
Unit number		$4\times3\ MW_e$	$14\times1\ MW_e$
Thermal input (MW_t)		61	38.7 (average)
Output (MW_e)		12	13 (average)
Electricity generated (MW h)		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
	Percentage of total ventilation air methane (%)	92	0
	Ventilation air flow (m^3/s)	~170	0
From drainage gas	Amount of CH_4, m^3 (out of 58,018,603 m^3)	20,809,167	29,588,962
	Percentage of total drainage gas methane	35.9	51.0
Continuous operational availability (%)		99.8 (~100% load)	96.3 ($\geq$50% load)
Total ventilation air usage (%)		92	
Total drainage gas usage (%)		86.9	
Total electricity generated (MW h)		192,916	



Tag	Description	Manufacturer	Model
E-1	Ventilation air filter/scrubbing	not specified	
E-2	Drainage gas filter/scrubbing	not specified	
E-3	Mixer & storage	not specified	
E-4	Air filter	not specified	
E-5	Drainage gas storage	not specified	
E-6	Lean-burn turbine units	Being developed	CSIRO lean-burn turbine
E-7	Gas engine units	Caterpillar	G3516

Fig. 20. Diagram of the combined 1% methane turbine and gas engine power generation system at the QLD mine.

ventilation air methane, and power output. Fig. 20 is a conceptual design of combined 1% methane lean-burn catalytic gas turbine and gas engine power generation plant at the QLD mine. Fig. 21 shows how the combined 1% methane turbine and gas engine power generation plant could operate at the QLD mine. For the 1% methane, turbine units are operated at almost 100% load. While there is a slight drop in gas engine efficiency from 33.7 to 31% when the load is reduced from the full-load to 50% load, it was considered simpler in operating terms to drop load rather than turn off surplus engines. Fig. 21 shows the variations of gas engine load and the remaining pure methane feed rate during the operation of gas engine plant from 10th January to 24th November 2002.

5.5.1.2. Economic analysis. Based on the system diagram of the combined 1% methane gas turbine and gas engine plant shown in Fig. 20 and the operating parameters in Table 19, a preliminary economic analysis was conducted. It was determined that four 3 MW_e 1% methane turbine units and 14 one-megawatt gas engine units are installed, and the operating and maintenance costs are estimated to be $2.34 million per year. Table 20 summarises the major capital costs of the combined 1% methane turbine and gas engine plant. Table 21 summarises the results of the preliminary economic analysis of the combined 1% methane turbine and gas engine plant at the QLD mine under different conditions. The results indicate that the application of the combined 1% methane gas turbine and gas engine plant at the QLD mine is economically feasible. As a basic case with no carbon credit, the break-even price of generating electricity is $23.3/MW h, and the internal rate of return is 18.8%. However, although the capacity of the combined 1% methane turbine and gas engine plant is the same as that

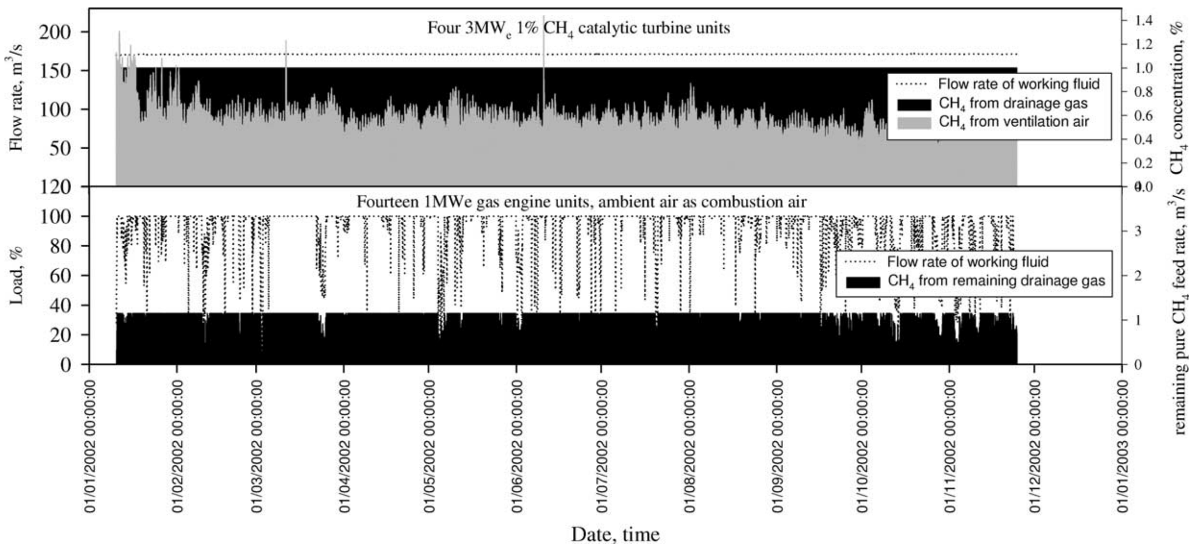


Fig. 21. Operating state of the combined 1% methane turbine and gas engine power plant at the QLD mine.

of the gas engine plant C in the Section 5.3.2, the combined 1% methane turbine and gas engine plant utilises 92% of the ventilation air methane and 86.9% of drainage gas better than the gas engine plant C using 18.7% of the ventilation air methane and 88.4% of the drainage gas during the 319 days; and also the combined 1% methane plant produces 192, 916 MW h of electricity which is higher than 190, 324 MW h of electricity produced by the gas engine plant C. When the scenario for economic assessment is changed, such as paying for the drainage gas, and no carbon credit for drainage gas methane, the results will be very different.

5.5.2. 1.6% methane turbine and gas engine power plant

5.5.2.1. Potential and operating status. The potential and operating status of the 1.6% methane lean-burn gas turbine power plant at the QLD mine was determined in Section 5.4.2, and this can be used to assist in determining the potential and operating status of the gas engines using the remaining drainage gas after the 1.6% methane turbine plant, and of the combined 1.6% methane turbine and gas engine plant at the QLD mine. The 1.6% methane turbine plant will use about 50% (or 86 m^3/s) ventilation air from the QLD mine. So, it is still possible to use ventilation air, for the gas engines as combustion air. Hence, similar to Section 5.3.2, based on the *remaining* drainage gas after the 1.6% methane turbine plant, as shown in Fig. 22, potential sizes of three gas engine plants using the remaining drainage gas were determined and are summarised below with the consideration of the supply rate of remaining ventilation air after the 1.6% methane turbine plant:

– *Gas engine power plant A*. When ambient air is used as combustion air, 12×1 MW$_e$ Caterpillar G3516 spark-ignition gas engines can be installed at the QLD mine. During the 319 days, the gas engine plant can be operated at the full load over 77.6% of the period, 75–99% load over 11.7% of the period, and 50–74% load over 6.6% of the period. A total of 25,407,292 m^3 methane (out of a total of 58,018,603 m^3 drainage gas

Table 20
Major capital costs of the combined 1% methane turbine and gas engine power plant

1% CH_4 power plant		Gas engine power plant	
Major equipment	Unit price	Major equipment	Unit price
1% CH_4 catalytic turbine unit[a], 3000 kW	$2,606,000	Gas engine unit[b], 1000 kW	$1,000,000
Fans for ventilation air	$14,000	Air filter	$5000
Filter/scrubbers for ventilation air	$800,000	Drainage gas storage	$30,000
Fan for drainage gas	$20,000	Fan for drainage gas	$50,000
Filter/scrubber for drainage gas	$100,000		
Pipeline for drainage gas	$200,000		
Mixer/storage	$200,000		

[a] The unit price of the lean-burn turbine is our best estimate.
[b] The unit price of Caterpillar G3516 gas engine is estimated to be about $1 million in the Australian market.

Table 21
Results of the preliminary economic analysis for the combined 1% methane turbine and gas engine power plant

	$0/$CO_{2\text{-e}}$	$5/$CO_{2\text{-e}}$	$10/$CO_{2\text{-e}}$
Plant size (MW_e)	26	26	26
Capital cost ($)	28,372,300	28,372,300	28,372,300
Capital cost ($/$kW_e$)	1091	1091	1091
Net present value ($)	32,037,285	98,943,802	165,850,319
Internal rate of return (%)	18.8	40.2	61.4
Break-even price of electricity ($/MW h)	23.3	−5.33	−33.95

methane), i.e. 43.8% of drainage gas, can be utilised to generate electricity of 85,414 MW h.

– *Gas engine power plant B*. When the remaining mine ventilation air is used as combustion air, we still install the above 12 gas engine units at the QLD mine, but their thermal input should be increased due to some methane in the ventilation air enters into the gas engines. Hence, the output of the plant should be higher. During the 319 days, the gas engine plant can be operated at the full load over 83.1% of the period, 75–99% load over 8.6% of the period, and 50–74% load over 5.1% of the period. A total of 23,362,511 m^3 methane (out of a total of 58,018,603 m^3 drainage gas methane), i.e. 40.3% of drainage gas, and 2,417,635 m^3 out of 28,200,149 m^3 ventilation air methane), i.e. 8.6% of the ventilation air methane, can be utilised to generate electricity of 86,790 MW h. The total amount of methane used in the gas engine plant is 25,780,146 m^3. It is obvious that extra electricity of 1376 MW h is generated by using extra 372,854 m^3 methane (combined methane from drainage gas and ventilation air) when the ventilation air is used for the plant b compared with the plant a using the ambient air. The ventilation air methane only contributes 9.4% of total amount of methane to the gas engines.

– Gas engine power plant C: when the mine ventilation air is used as combustion air, 13×1 MW_e Caterpillar G3516 spark-ignition gas engines are installed at the QLD mine to use the remaining drainage gas. During the 319 days, the gas engine plant can be operated at the full load over 78.4% of the period, 75–99% load over 11.4% of the period, and 50–74% load over 6.3% of the period. A total of 25,011,247 m^3 methane (out of a total of 58,018,603 m^3 drainage gas methane), i.e. 43.1% of drainage gas, and 2,590,716 m^3 (out of 28,200,149 m^3 ventilation air methane), i.e. 9.2% of the ventilation air methane, can be utilised to generate electricity of 92,814 MW h. The total amount of methane used in this gas engine plant is 27,601,963 m^3. It is obvious that extra electricity of 7400 MW h is generated by using extra 2,194,671 m^3 methane (combined methane from drainage gas and ventilation air) when the ventilation air is used for the plant c compared with the gas engine power plant a.

The combined technologies with the maximum utilisation of drainage gas and ventilation air methane at the QLD mine are detailed in Table 22, summarising the major operating parameters of the 1.6% methane turbine and gas engine power plant c as the best case among the three gas engine plants a–c. The features of the two power generation technologies in terms of usages of drainage gas and ventilation air methane, and power output are also

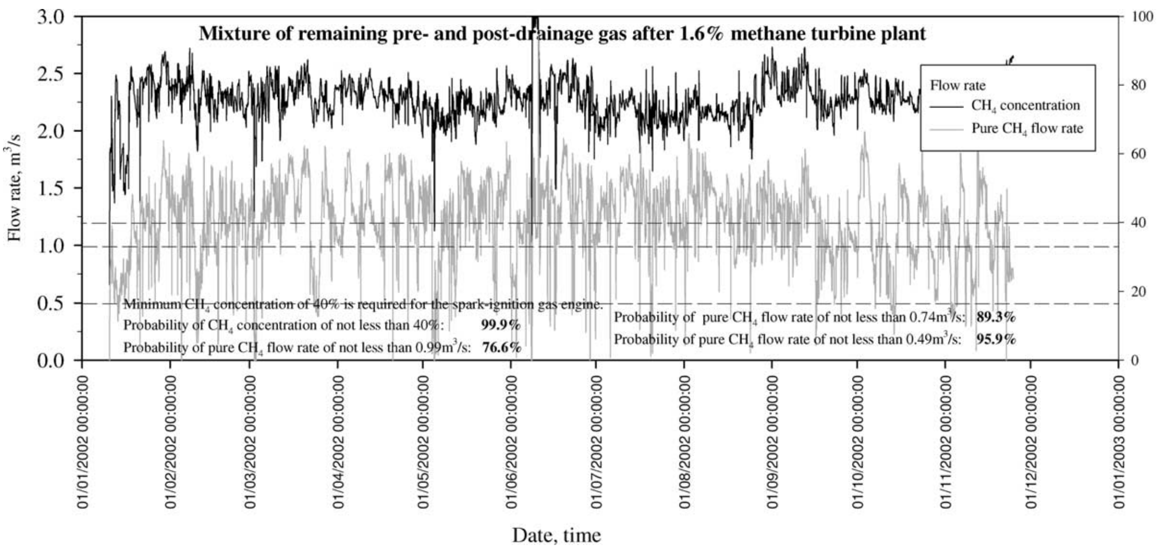


Fig. 22. Potential of the gas engine power generation plant after the 1.6% methane turbine plant at the QLD mine.

Table 22
Major operating parameters and features of the combined 1.6% methane turbine and gas engine power plant at the QLD mine

10th January to 24th November 2002 (319 days)			
Type of power generation unit		Combined 1.6% CH_4 turbine and gas engine plant	
		1.6% CH_4 turbine	Gas engine
Unit number		3×3.2 MW_e	13×1 MW_e
Thermal input (MW_t)		~49	36.1 (average)
Output (MW_e)		~9.5	12.2 (average)
Electricity generated (MW h)		74,821	92,814
Total methane used (m^3)		37,410,336	27,601,963
From ventilation air	Amount of CH_4, m^3 (out of 28,200,149 m^3)	12,608,997	2,590,716
	Percentage of total ventilation air methane (%)	44.7	9.2
	Ventilation air flow (m^3/s)	~85	17 (average)
From drainage gas	Amount of CH_4, m^3 (out of 58,018,603 m^3)	24,801,339	25,011,247
	Percentage of total drainage gas methane	42.7	43.1
Continuous operational availability (%)		99.5 (~100% load)	96.1 ($\geq$50% load)
Total ventilation air usage (%)		53.9	
Total drainage gas usage (%)		85.8	
Total electricity generated (MW h)		167,635	

compared. Fig. 23 is a conceptual design of combined EDL 1.6% methane lean-burn catalytic gas turbine and gas engine (gas engine plant c) power generation plant at the QLD mine.

Fig. 24 shows how the combined 1.6% methane turbine and gas engine power generation plant would operate at the QLD mine. For the 1.6% methane, turbine units are operated at almost 100% load. Similar to the gas engine plant discussed in Section 5.3.2, even though the remaining drainage gas supply rate after the 1.6% methane turbines is reduced. It is possible that one or more of the 13 gas engines could be stopped to maintain other gas engines operate at full-load, but this has not been considered in Fig. 24, which shows variations of gas engine load and the remaining pure methane feed rate during the operation of gas engine plant from 10th January to 24th November 2002.

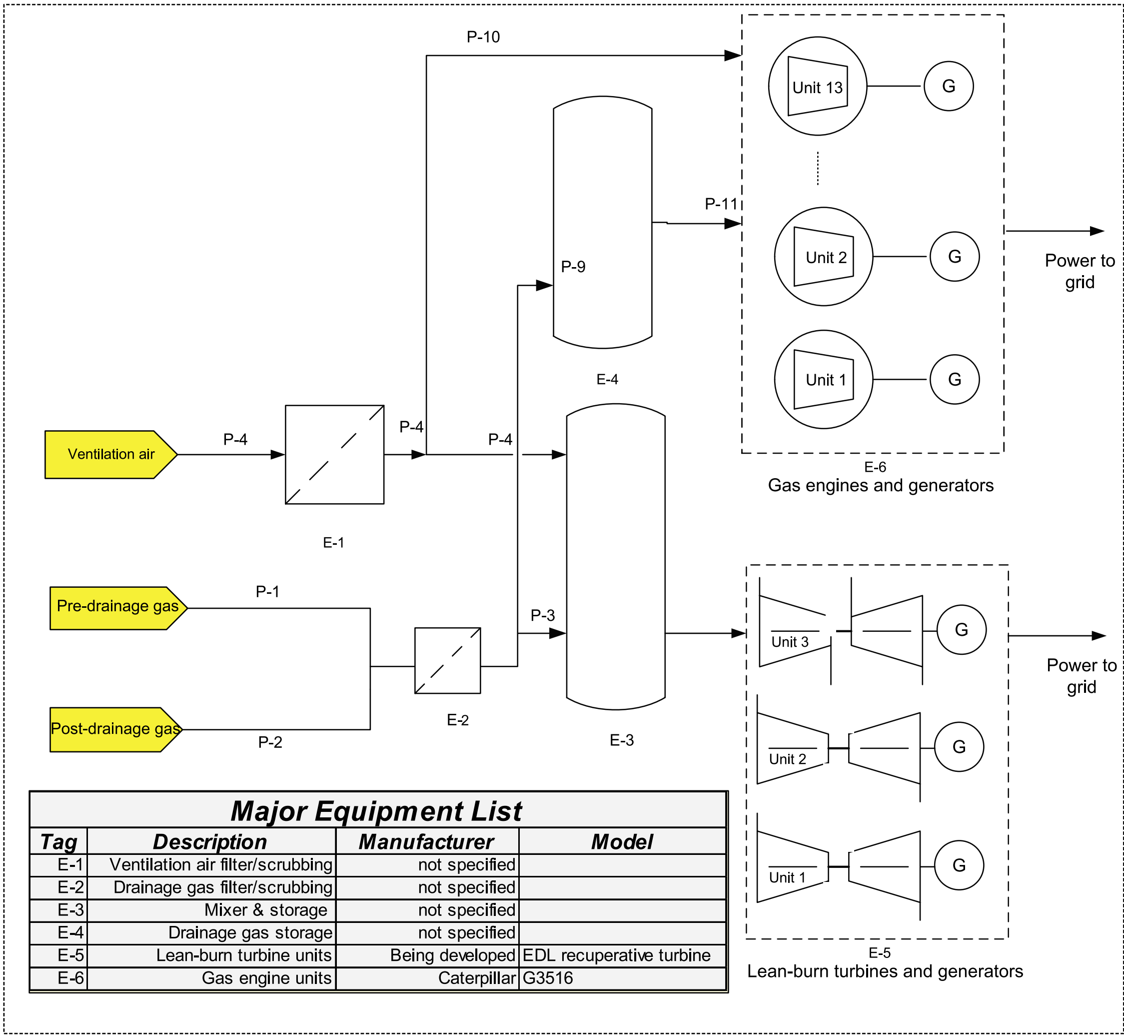
5.5.2.2. Economic analysis. Based on the system diagram of the combined 1.6% methane turbine and gas engine plant shown in Fig. 23 and the operating parameters in Table 22, a preliminary economic analysis was conducted. It was determined that three 3.2 MW_e 1.6% methane turbine units and 13 1 MW_e gas engine units are required, and the operating and maintenance costs are estimated to be $2.16 million per year. Table 23 summarises the major capital costs of the combined 1.6% methane turbine and gas engine plant. Table 24 summarises the results of preliminary economic analysis of the combined 1.6% methane turbine and gas engine plant at the QLD mine under different conditions. The results shown in Table 24 indicate that the application of the combined 1.6% methane gas turbine and gas engine plant at the QLD mine is also economically feasible. As a basic case with no carbon credit, the break-even price of generating electricity is $23.9/MW h, and the internal rate of return is 18.5%. It seems that the combined 1.6% methane power plant is almost the same as that of the combined 1% methane power plant in terms of economic performance. However, as determined above, the capacity of the combined 1% methane turbine and gas engine plant is higher than that of the combined 1.6% methane power plant. Also, the combined 1% methane turbine and gas engine plant utilises 92% of the ventilation air methane and 86.9% of drainage gas, a higher mitigation performance than the combined 1.6% methane power plant, which uses 53.9% of the ventilation air methane and 85.8% of the drainage gas from 10th January to 24th November 2002. The economic assessment changes with factors such as paying for the drainage gas and being paid carbon credits.

5.6. Comparison of the technologies

Direct comparison of all the technologies is difficult as, for example, the methane purification plant yields a different product than the other technologies. This means that the assumptions used as to product sales can influence the outcome of economic analysis. The purification plant will not be compared with the power plants in terms of the plant size and plant throughput, but will be considered in terms of usage of methane from ventilation and drainage gas, and overall economic parameters.

5.6.1. Plant potential

Fig. 25 compares the plant sizes and throughput for the power plants. The gas engine power plant has the same



Major Equipment List

Tag	Description	Manufacturer	Model
E-1	Ventilation air filter/scrubbing	not specified	
E-2	Drainage gas filter/scrubbing	not specified	
E-3	Mixer & storage	not specified	
E-4	Drainage gas storage	not specified	
E-5	Lean-burn turbine units	Being developed	EDL recuperative turbine
E-6	Gas engine units	Caterpillar	G3516

Fig. 23. Diagram of the combined 1.6% methane turbine and gas engine power generation system at the QLD mine.

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. Fig. 26 shows that the combined 1% methane turbine and engine plant mitigates and utilises more methane from ventilation air and drainage gas, particularly methane in the ventilation air. Fig. 25 shows that the gas turbine plant has the smallest plant size compared with the other power plants, while designed to maximise the mitigation of methane from both ventilation air and drainage gas.

Fig. 27 indicates how much the ventilation air methane and drainage gas are mitigated and utilised annually by different technologies. The TFFR, CFFR or CMR plants can mitigate 100% of ventilation air methane. Where the intent is maximum mitigation and utilisation of ventilation air methane, the 1% methane lean-burn turbine plant is the best option. The combined 1% methane turbine and gas engine plant is the best option for maximising the use of the combined mine methane streams. The PSA methane purification plant and the conventional gas turbine plant do not mitigate and utilise the ventilation air methane.

As demonstrated in Fig. 27, the combined 1% methane turbine and gas engine plant mitigates most of greenhouse gas—methane in terms of CO_2 equivalent ($CO_{2\text{-}e}$) compared with the other plants. It is possible to mitigate drainage gas methane by using TFFR, CFFR or CMR technologies, and all of the mine methane can be mitigated by these technologies, but this wastes ‘high quality’ fuel by utilising it with lower than optimal efficiency.

Generally, the plant potential and operating parameters determined were accurate for the plants at the QLD mine

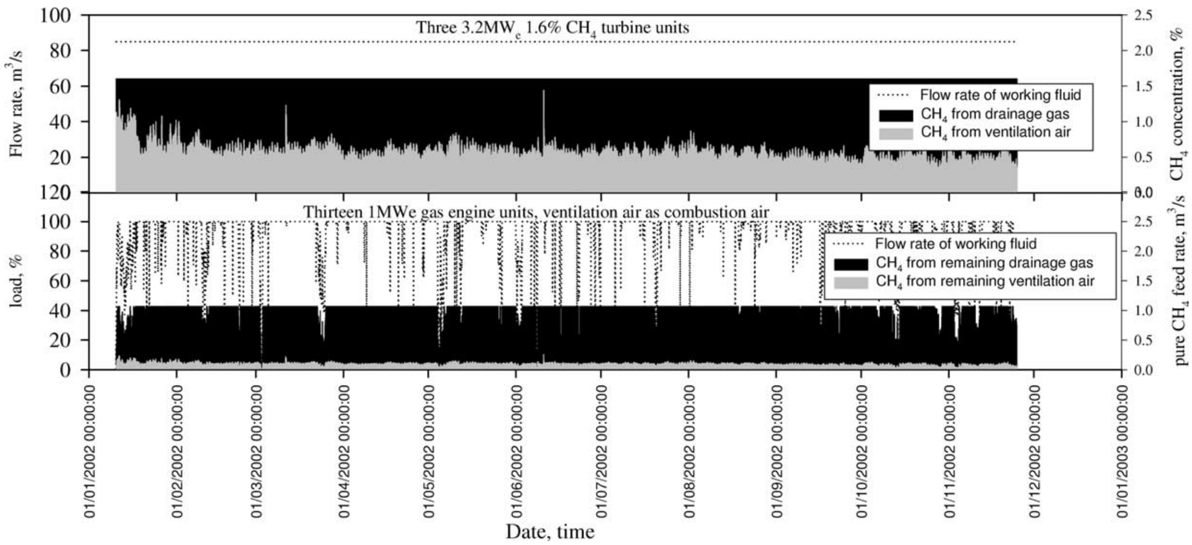


Fig. 24. Operating state of the combined 1.6% methane turbine and gas engine power plant at the QLD mine.

Table 23
Major capital costs of the combined 1.6% CH_4 turbine and gas engine power plant

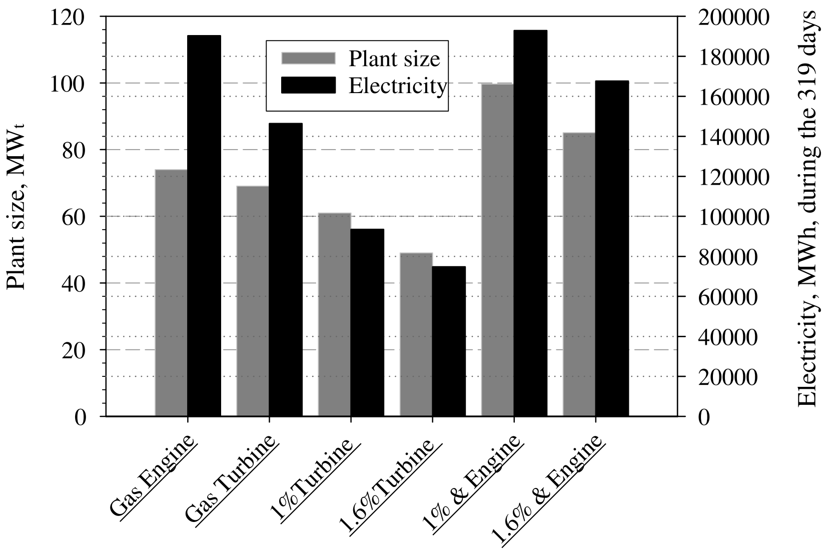
1.6% CH_4 power plant		Gas engine power plant	
Major equipment	Unit price	Major equipment	Unit price
1.6% CH_4 recuperative turbine unit[a], 3167 kW	$ 2,714,000	Gas engine unit[b], 1000 kW	$1,000,000
Fans for ventilation air	$9000	Ventilation air filter/scrubber	$80,000
Filter/scrubbers for ventilation air	$450,000	Drainage gas storage	$30,000
Fan for drainage gas	$22,000	Fan for drainage gas	$48,000
Filter/scrubber for drainage gas	$120,000		
Pipeline for drainage gas	$200,000		
Mixer/storage	$150,000		

[a] The unit price of the lean-burn turbine is our best estimate.
[b] The unit price of Caterpillar G3516 gas engine is estimated to be about $1 million in the Australian market.

based on the real methane emission data from 10th January to 24th November 2002, as shown in Fig. 6. A total of 67.2% of mine methane is emitted from the drainage gas system at the QLD mine and this is different from most of the gassy coal mines, where an average of 64% of mine methane is emitted through the ventilation air system. This is likely to be due to mine site-specific conditions, for example, the in situ gas content is very high at the QLD mine, averaging 13 m^3/t, and this needs to be reduced to 4 m^3/t before mining for safety reasons. Other gassy mines having an average in-situ gas content of approximately 6 m^3/t. The gas permeability is also higher at the QLD mine. Nevertheless, when most of mine methane, is emitted from ventilation air system, the lean-burn turbines should have a much better performance than the conventional gas turbine and gas engine because most of the mine methane can be mitigated and utilised by the lean-burn turbines. This has been demonstrated by a technical and economic assessment for a NSW mine [20], and in Appendix. Appendix presents the characteristics of methane emissions from the NSW mine and summarises major performance parameters determined for conventional gas turbine plant, gas engine plant, 1% methane

Table 24
Results of the preliminary economic analysis for the combined 1.6% methane turbine and gas engine power plant

	$0/t$CO_{2\text{-e}}$	$5/t$CO_{2\text{-e}}$	$10/t $CO_{2\text{-e}}$
Plant size (MW_e)	22.5	22.5	22.5
Capital cost ($)	24,423,300	24,423,300	24,423,300
Capital cost ($/$kW_e$)	1085	1085	1085
Net present value ($)	26,617,113	83,586,848	140,556,583
Internal rate of return (%)	18.5	39.7	60.6
Break-even price of electricity ($/MW h)	23.9	−4.2	−32.2



Gas Engine - Gas engine power plant
Gas Turbine - Gas turbine power plant
1% Turbine - 1% CH_4 lean-burn turbine plant
1.6% Turbine - 1.6% CH_4 lean-burn turbine plant
1% & Engine - combined 1% CH_4 lean-burn turbine and gas engine power plant
1.6% & Engine - combined 1.6% CH_4 lean-burn turbine and gas engine power plant

Fig. 25. A comparison of plant sizes and electricity production.

catalytic turbine plant, 1.6% methane recuperative turbine plant, combined 1% turbine and gas engine plant and combined 1.6% turbine and gas engine plant, respectively, using the same methods as were used for the QLD mine.

5.6.2. Plant economics

Fig. 28 summarises capital costs for all the plants and the net present values at different rates of carbon credit payment. It is clear that the TFFR, CFRR or CMR plants are not feasible in terms of investment without the benefit of carbon credit. In order to make a financial return when mitigating mine ventilation air methane, the carbon credit must be higher than \$5/t $CO_{2\text{-e}}$. For example, as shown in Fig. 28, the TFFR plant has a net present value of \$11,390,046 when the carbon credit is \$10/t $CO_{2\text{-e}}$, and the internal rate of return is 14.4%, as shown in Fig. 29. Given this level of carbon credit,

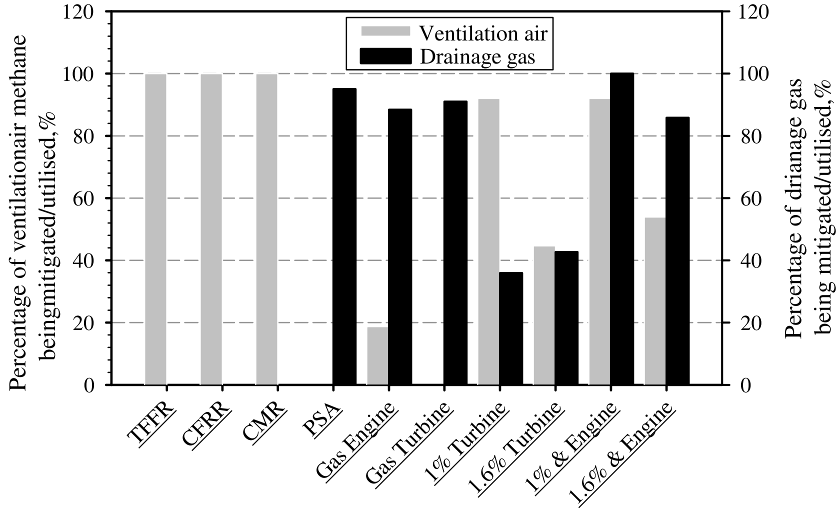


Fig. 26. A comparison of methane mitigation and utilisation.

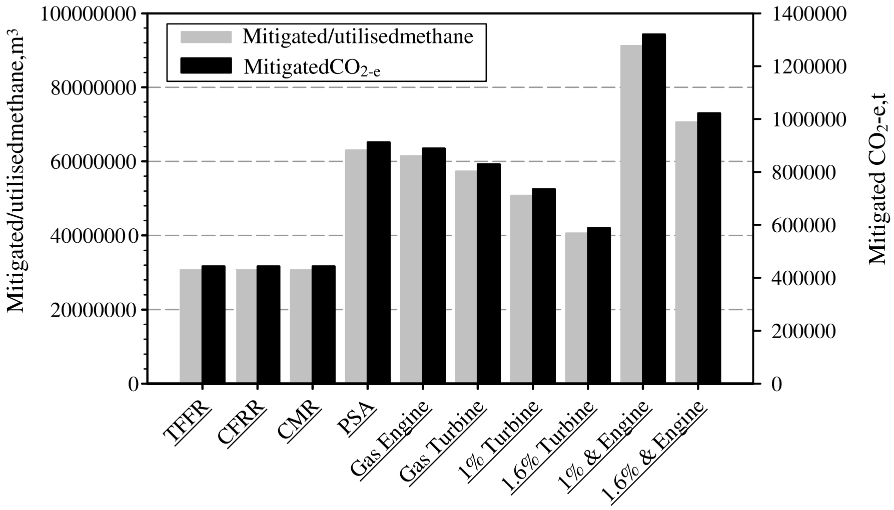


Fig. 27. Amount of mitigated/utilised mine methane.

the TFFR technology for the mitigation of ventilation air methane could be considered a reasonable investment. It can be seen from Fig. 28 that the combined 1% methane turbine and gas engine plant has the highest net present value when carbon credit is paid.

Fig. 29 compares the internal rate of return and the break-even price of electricity or natural gas for the all types of plants at the QLD mine. Though the combined 1% methane turbine and gas engine plant has the highest throughput and net present value, its internal rate of return is less than that of the conventional gas turbine just using the drainage gas. Fig. 29 also indicates that the PSA purification plant has the highest internal rate of return when producing natural gas, but the assumption for this case is that an industrial consumer is located near the mine. It is also interesting to see that when carbon credits are assumed, the break-even price of electricity is negative for all the power plants, excepting the gas engine power plant at a carbon credit of \$5/t $CO_{2\text{-e}}$. This means that the electricity can be sold at any price and a profit will still be made.

If drainage gas is sold to the plants as a ‘high quality’ fuel, the lean-burn turbines offer higher comparative returns because of the low usage of supplementary fuel. This is a likely scenario where it has been identified that drainage gas is a useful commodity that can be used to generate power or produce pipeline gas.

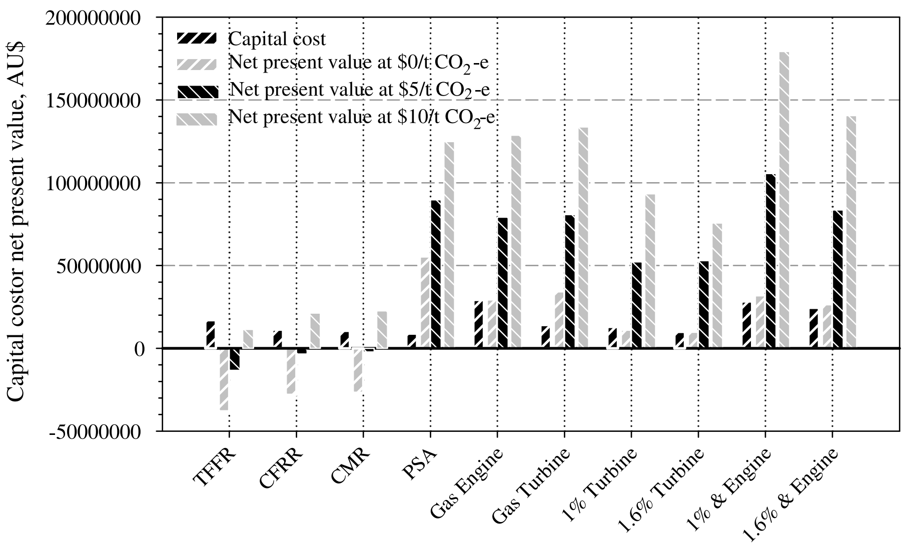


Fig. 28. Plant capital cost and net present values.

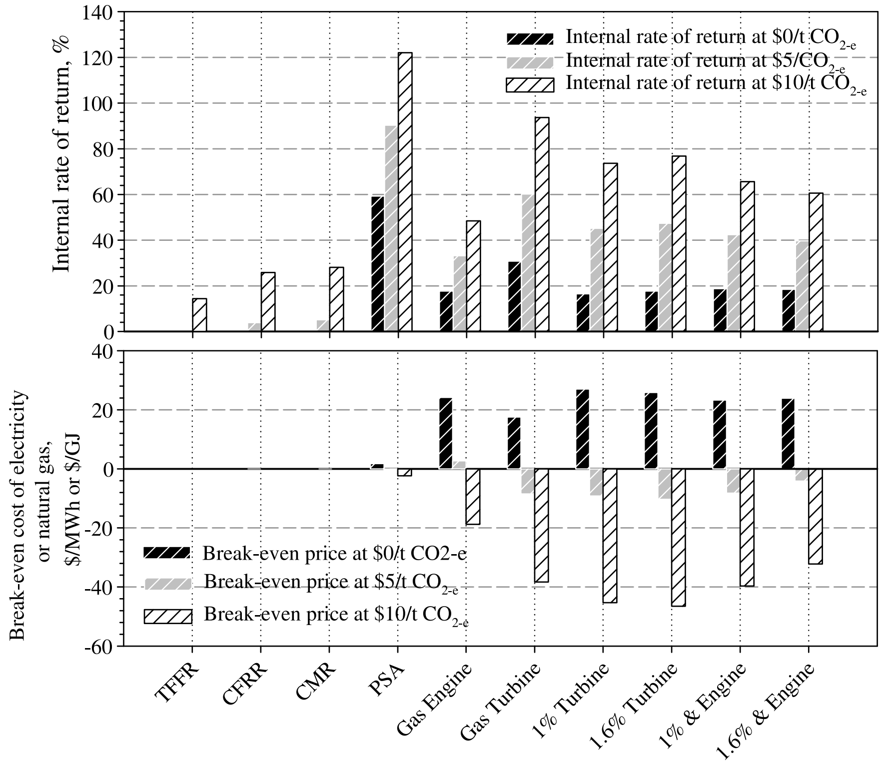


Fig. 29. Internal rate of return and break-even prices of electricity/natural gas.

6. Conclusions

This paper first classified existing and developing technologies for coal mine methane mitigation and utilisation, and then compared and discussed features of different technologies to identify potential technical issues for each technology when it is implemented at a mine site. Detailed results of the technical and economic assessment of the implementation of a variety of the technologies at the QLD mine have been presented as the case study on the basis of real mine methane emission data over about a one-year timeframe. The following conclusions are made:

Drainage gas

(1) Pressure Swing Adsorption purification technology is commercially available for purifying natural gas. When the mine drainage gas stream has methane content greater than 70%, it should be possible to use this technology to purify the drainage gas if impurities, such as nitrogen, oxygen, carbon dioxide or water vapour, can be efficiently removed. It could yield a reasonable return on investment if the gas can be used locally or sold to a pipeline. At present, there is no local market or existing pipeline for the gas but a gas pipeline may be constructed through the region in the future. It is unlikely to be practical to purify gas streams with less than 40% methane and even an overly expensive design would release substantial greenhouse gas emissions in dilute methane waste streams.

(2) Drainage gas could be used for co-firing at conventional coal-fired power stations. However, the lack of availability of pulverised coal-fired power stations convenient to mines limits the suitability of this technique, and variations in methane concentration and supply rate would affect the operation of power stations, and increasing complexity of the power stations.

(3) Drainage gas having a minimum methane concentration of 40% can be used by the spark-ignition gas engine for power generation. This technology has been commercially demonstrated, and the case study showed that this technology should be feasible both technically and economically for its application at mine sites. However, the drainage gas supply continuity will affect the gas engine plant operation, which needs to maintain at least 50% load of the plant or turn off one/serval gas engine units to keep others running. Also, the studies on the homogenous charge compression ignition engines have indicated that this type of engine may be operated at methane concentration as low as 5% (volume percentage).

(4) Based on the combustion properties of methane, it is feasible to set up a stable combustion when the drainage

gas contains about 30% CH_4. Generally, the ventilation air is not considered as combustion air because the gas turbines use a significant part of the combustion air for dilution and cooling processes, which would result in a significant amount of methane in the ventilation air passing through the gas turbine systems without oxidation. Some modification of the combustors of the conventional gas turbines is required before burning drainage gas. In general, it is technically and economically feasible to use the modified gas turbines at mine sites to generate power when the methane concentration and supply rate variation are in the acceptable range.

(5) Currently, fuel cells are expensive and this precludes commercial applications. High temperature fuel cells are still under development to reduce capital cost and increase reliability. It would be expected that the fuel cell technology could have potential applications when a technology breakthrough takes place in terms of cost reduction and greater reliability.

(6) The minimum methane concentration for methanol production is 89% and it is difficult to maintain such high methane concentrations in the drainage gas with an availability of 95%. For example, in the case study mine the probabilities of the methane concentration being over than 89% are 7.7, 3.2 and 1% for pre-drainage gas, post-drainage gas and the mixture of pre- and post-drainage gas, respectively. It is not practical to use the methanol production technology unless the methane concentration and the availability meet these requirements. Similarly for carbon black production, the current demonstration plant uses coal bed methane with the minimum methane concentration of 84%. However, for the coal mine of the case study, the probabilities that the methane concentrations are more than 84% are 23.3, 8.5 and 5.6% for pre-drainage gas, post-drainage gas and the mixture of pre- and post-drainage gas, respectively. The oxygen-enriched air carbon black production technology could lower the minimum methane concentration to 50%, but this needs to be developed and demonstrated at pilot-scale before its commercialisation.

Ventilation air

(1) In terms of the ancillary uses of ventilation air methane, ventilation air could be used as combustion air in: (a) pulverised coal-fired power stations, (b) hybrid waste coal/methane combustion units, (c) gas turbines, and (d) internal combustion engines.
   - In general, the lack of availability of pulverised coal-fired power stations convenient to mines limits the suitability of this technique. Technically, for existing pulverised coal-fired power stations variations of methane in ventilation air might affect a stable operation of the conventional power station boiler furnaces depending on the methane concentration in air and the flow rate of ventilation air. This also increases the complexity of power station operation.
   - As to the hybrid waste coal/methane fluidised bed combustion, there is no experimental study yet that proves the methane can be fully oxidised in a fluidised bed combustion unit. It is recommended that hybrid waste coal/methane combustion should be investigated in detail under real conditions similar to a mine before the development of a larger-scale unit. Use of high quality coal should also be evaluated.
   - For conventional gas turbines, the methane from ventilation air only contributes a small percentage of the turbine's fuel, and also the use of this air for combustion dilution and cooling of the turbine inlet scroll and first stage in normal industrial gas turbines will result in a significant fraction of the methane passing through the turbine without combusting. Moreover, the modification of the gas turbine's combustor is generally required even for the utilisation of drainage gas.
   - Regarding gas engines, the operation of the Caterpillar G3516 gas engines at the Appin Colliery has demonstrated that methane from ventilation air only contributes between 4 and 10% of engine fuel, corresponding to the consumption on the order of 20% ventilation emissions. The case study indicated that about 9% methane from ventilation air can be used by the gas engine plant. Typically, only a small percentage of methane from ventilation air can be used by this technology.

(2) The principal use technologies for mitigation of ventilation air methane includes a group of three technologies based on combustion only, namely TFRR, CFRR and CMR.
   - The minimum methane concentrations required for operation of these technologies are 0.2, 0.1 and 0.4% for the TFRR, CFRR and CMR units, respectively. The length of time that both the TFRR and CFRR can operate continuously at the minimum concentrations is poorly defined, and this needs to be clarified. Indeed it is a practical issue in terms of mine-site operation, due to methane concentrations in ventilation air could be lower than 0.19% for extended periods lasting from a few hours to a few weeks.
   - The TFRR, CFRR and CMR technologies are technically feasible for destroying ventilation air methane when the methane concentration in air exceeds the minimum requirement by each technology and economic performance is not critical. With respect to engineering applicability, there could be a plant size issue at a mine for the TFFR technology, as an extremely large plant is required to handle all of the mine ventilation air from a typical mine.

- If the methane concentration is almost constant, heat recovered from the energy release during methane combustion can be used to generate power. If the methane concentration in the ventilation air is variable, it is difficult to extract useful energy, as the variations in methane concentration are likely to cause instability in the system. This needs to be demonstrated in a pilot-scale plant before larger-scale commercialisation.
- The case study showed that without carbon credits there is no financial incentive to invest in mine ventilation air methane mitigation. If the carbon credit is above \$10/t $CO_{2\text{-e}}$ there could be significant financial returns.

(3) The other principal use of the ventilation air methane that was considered is both mitigation and utilisation of the ventilation air methane through the use of lean-burn gas turbines.
- Reduction of the minimum methane concentration at which a turbine system can operate has substantial advantages in reducing usage of methane from other sources. The 1% methane catalytic combustion gas turbine can use a much greater proportion of ventilation air compared with the 1.6% CH_4 recuperative gas turbine. Thermodynamically, lean-burn catalytic turbines can be operated at lower methane concentrations, perhaps to 0.8%.
- The technical and economic assessment demonstrated that the implementation of 1 and 1.6% methane gas turbines in the QLD mine is feasible. The results indicated that 55.5% of the fuel for firing the 1% methane catalytic turbine is the methane from ventilation air, compared to only 33.7% for the 1.6% methane recuperative turbine, depending on the methane concentration in the ventilation air. Also, the 1% turbine can utilise about 92% of ventilation air with a higher output, but the 1.6% turbine just uses 44.7% of ventilation air. It is also economically feasible to apply these two lean burn gas turbine technologies at the mine without any carbon credits. When carbon credits are available there should be significant financial return when operating the plant.
- For the case study mine, 67.2% of mine methane is emitted in the drainage gas, which is significantly different from most gassy coal mines, which average about 64% of mine methane being emitted via the ventilation air system. Therefore, the lean-burn turbines should have a comparatively improved performance at typical gassy mines. Therefore, the 1% methane turbine technology is by far the best option for the utilisation of ventilation air methane.
- A concentrator could be used to enrich methane in mine ventilation air to levels that meet the requirements of the lean-burn methane turbine technologies, such as catalytic and recuperative gas turbines. If the methane can be concentrated to approximately 30% or higher, conventional gas turbines can be employed to generate electricity without significant modifications and no need for additional fuel such as the drainage gas. A successfully demonstrated, a cost-effective concentrator would be a significant breakthrough in the utilization of mine methane.

Combination of the technologies

To mitigate and utilise all of mine methane both from ventilation air and drainage gas, this study proposed a new method that is a combination of the 1% methane lean-burn gas turbine and conventional gas engine (e.g. Caterpillar G3516). The technical and economic assessment at the QLD mine demonstrated:

(1) About 92% of ventilation air methane and 86.9% of drainage gas can be mitigated and utilised at the mine with the highest plant throughput compared with other technologies discussed in this paper.
(2) The combined 1% methane lean-burn turbine and gas engine plant is economically feasible without any incentives, such as carbon credits. But any incentive should help investors earn more. For example, when the carbon credit is \$5/t $CO_{2\text{-e}}$, the break-even price of electricity is negative \$5.33/MW h, a result that shows that profit can be made when selling the electricity at any price.
(3) Although the combined 1% methane turbine and gas engine plant has the highest throughput and net present value, its internal rate of return is not higher than the conventional gas turbine just using the drainage gas. In general, the type of technology that provides the best solution for a mine will depend on several factors such as: (a) highest investment return, (b) governmental policy, such as carbon credit only for ventilation air methane or for all the mine methane, (c) mine-site specifications, and (d) mine safety. However, only the lean-burn turbine is capable of using most of the ventilation air methane, which is usually the largest stream of methane emitted from most gassy mines, unlike the QLD mine, while making a return on the investment.

An important note is that the economic assessment performed was only preliminary, and further analysis is required to validate the economic results for specific sites. In addition, it is very important to investigate any possible safety issue when any type of mine methane mitigation and utilisation unit is connected to mine ventilation air shaft and a drainage gas plant.

Acknowledgements

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Appendix. Plant potential at a typical gassy coal mine

A.1. Characteristics of methane emissions

On average of approximately 64% of methane emitted from gassy mines is emitted through the ventilation air systems. A New South Wales (NSW, Australia) coal mine is chosen as an example. Fig. A1 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 pointed out that the post-drainage gas goes into the pre-drainage gas pipeline to the gas drainage plant. Also, it can be seen from Fig. A1 that the information on the drainage gas was not correctly recorded in the mine data system from 2 August to 24 November 2003. Therefore, the methane emission data from 3 May to 1 August 2003, and from 25 November 2003 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 in the following.

- Methane emissions: 84,138,048 m^3/yr from the ventilation air, 46,870,380 m^3/yr from the drainage gas.
- Percent of methane emitted from the ventilation air is 64.2%.
- Possible sharpest methane variation rate is 0.01% CH_4/h.
- 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: 1.47 m^3/s.

A.2. Plant potential

The method, which is used to determine the plant potential at the NSW mine for different methane mitigation and utilisation technologies is the same as that used for the QLD mine. Similarly, the availability of the plant operation is specified to be at least 95%. The plant potential is then determined for a conventional gas engine plant, conventional gas turbine plant, 1% methane catalytic turbine plant, 1.6% methane recuperative gas turbine plant, combined 1% methane turbine and gas engine plant, and combined 1.6% methane turbine and gas engine plant. Table A1 summarises the major performance parameters for these power plants so that the potential of the plants can be easily compared. Therefore, it is clear for a typical gassy coal mine, such as the NSW mine that the 1% methane turbine can mitigate and utilise a much greater proportion of ventilation air methane, 98.1%, compared with the 1.6% methane turbine plant using only 35.5% of the ventilation air methane. The combined 1% methane turbine and gas engine plant can use 82.4% of

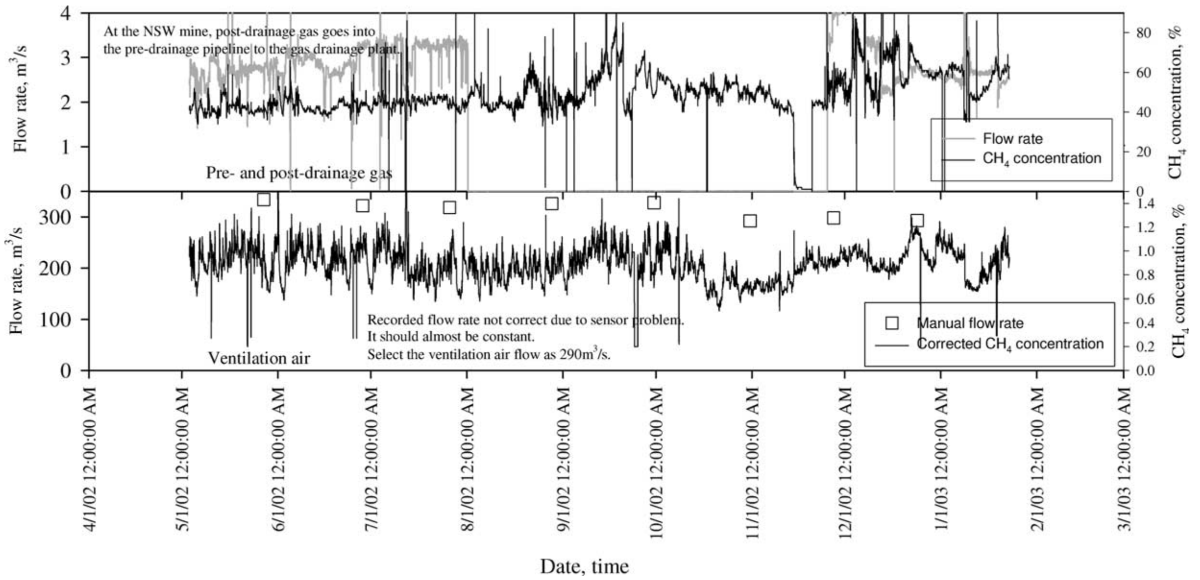

Fig. A1. Characteristics of methane emissions from the NSW coal mine.

Table A1
Major performance parameters of the six types of power plants at the NSW mine

Technology	Type of power generation unit and number		Thermal input MW_t (average)	Power output, MW_e (average)	During the 151 days			Average in 2002 (based on the data over the 151 days)			
					Electricity generated (MW h)	*Ventilation*: amount of CH_4, m^3 (out of 34,211,462 m^3)	*Drainage*: amount of CH_4, m^3 (out of 18,250,124 m^3)	Electricity generated (MW h)	Percentage of ventilation air methane (%)	Percentage of drainage methane (%)	Percentage of total methane (%)
Gas engine	17×1 MW_e Caterpillar G3516		48.5	16.3	58,302	2,654,715	14,639,317	133,882	7.8	80.2	33.0
Gas turbine	4×3.37 MW_e CENTAUR 40		44.8	12.4	44,077	0	15,986,341	101,217	0.0	87.6	30.5
1% CH_4 turbine	7×3 MW_e 1% turbine		104.4	20.9	73,498	33,550,746	3,699,174	168,778	98.1	20.3	71.0
1.6% CH_4 turbine	4×3 MW_e 1.6% turbine		60.1	12.0	42,479	12,160,093	9,295,861	97,547	35.5	50.9	40.9
Combined 1% turbine and gas engine	7×3 MW_e 1% turbine	6×1 MW_e Caterpillar G3516	121.1	26.5	93,618	33,550,746	9,664,773	214,980	98.1	53.0	82.4
Combined 1.6% turbine and gas engine	4×3 MW_e 1.6% turbine	4×1 MW_e Caterpillar G3516	71.2	15.75	55,858	12,775,578	12,646,917	128,270	37.3	69.3	48.5

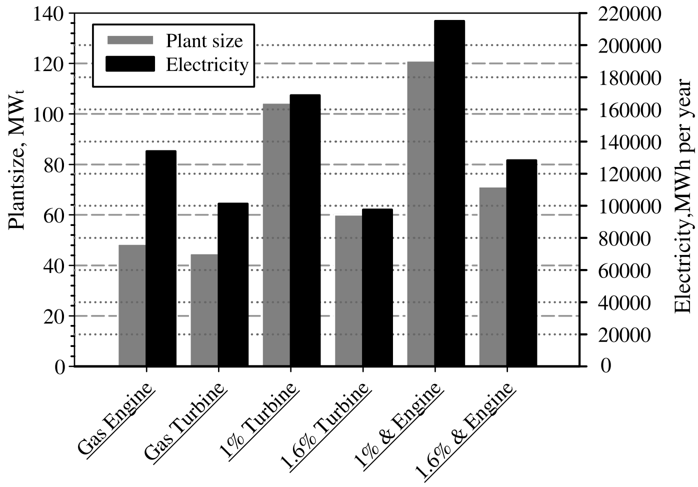

Fig. A2. A comparison of plant sizes and electricity production at the NSW mine.

all the mine methane including 98.1% of the ventilation air. As shown in Fig. A2, 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), the electricity production, the mitigation and utilisation of the ventilation air methane.

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