Technical and Economic Assessment: Mitigation of Methane Emissions from Coal Mine Ventilation Air

Coalbed Methane Outreach Program
Climate Protection Division
U.S. Environmental Protection Agency

COALBED METHANE OUTREACH PROGRAM

The Coalbed Methane Outreach Program (CMOP) is a part of the U.S. Environmental Protection Agency's (U.S. EPA) Climate Protection Division. CMOP is a voluntary program that works with coal companies and related industries to identify technologies, markets, and means of financing profitable recovery and use of coal mine methane (a greenhouse gas) that would otherwise be vented to the atmosphere.

CMOP assists the coal industry by profiling coal mine methane project opportunities at the nation's gassiest mines, conducting mine-specific technical and economic assessments, and identifying private, state, local and federal institutions and programs that could catalyze project development.

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Cover photo: Appin power plant, New South Wales, Australia. Courtesy of Energy Developments Limited.

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CONTENTS

APPENDICES

TABLES

FIGURES

UNITS OF MEASURE AND ACRONYMS

Units of Measure:

Btu	British thermal unit
cf	Cubic feet
cfm	Cubic feet per minute
cfs	Cubic feet per second
GJ	Gigajoule (billion Joules)
J	Joule
kPa	Kilo Pascal
kW	Kilowatt
kWh	Kilowatt hour
$kW_{(e)}$	Kilowatt (electric)
$kW_{(t)}$	Kilowatt (thermal)
m^3	Cubic meters
m^3/d	Cubic meters per day
m^3/m	Cubic meters per minute
m^3/s	Cubic meters per second
mcfd	Thousand cubic feet per day
MJ/sm^3	Megajoule (million Joules) per standard cubic meter
MW	Megawatt
MWh	Megawatt hour
M	Million (SI)
mm	Million (English)
Mm^3	Million cubic meters
mmBtu	Million British thermal units
mmcfd	Million cubic feet per day
Mt	Metric tonne
psig	Pounds per square inch, gauge

Acronyms:

CFRR	Catalytic Flow-Reversal Reactor
U.S. EPA	U.S. Environmental Protection Agency
IC	Internal Combustion
IRR	Internal Rate of Return
TFRR	Thermal Flow-Reversal Reactor
VOCs	Volatile organic compounds

GLOSSARY

Adiabatic	Pertaining to constant heat value; with no external heat exchange.
Air intake	Combustion air inlet (e.g., of an engine).
Auto-combustion	Combustion that can sustain itself without additional fuel; an exothermic reaction.
Autothermic	Pertaining to a combustion process that can sustain itself; auto-combustion.
Endothermic	A reaction that requires a net energy input (e.g., in addition to the fuel value of the methane contained in the ventilation air); opposite of exothermic
Evasé	Cone shaped discharge plenum.
Exothermic	A reaction that supplies excess energy (e.g., requires no additional fuel value other than methane contained in the ventilation air); opposite of endothermic.
Inby	Away from the mine entrance (see outby).
Mine-mouth power plant	A power plant co-located with a coal mine.
Outby	Toward the mine entrance (see inby).
Oxidation	The combination of a substance with oxygen (e.g., combustion).
Parasitic loss	That part of a prime mover's output that is consumed by ancillary plant components.
Prime mover	A machine or mechanism that turns energy into work.
Regenerative heat exchange	A process where heat is received, temporarily stored, and released.
Voidage	A measure of bed porosity; percent of volume not occupied by a solid material.

EXECUTIVE SUMMARY

Gassy underground coal mines in the U.S. and around the world release ventilation air containing coal mine methane (CMM) at concentrations generally below 1.0 percent methane. With few exceptions the mines operators allow the release of the methane to the atmosphere without attempting to capture and use it. CMM emissions account for approximately 10 percent of anthropogenic methane emissions worldwide, and methane emissions from mine ventilation air comprise the largest portion of all CMM liberated worldwide.

When compared with drained CMM (e.g., in-seam and gob gas), ventilation air CMM is the most difficult to use as an energy source because air volumes are large and require costly handling equipment, and the methane resource is dilute and variable.

This report examines current and evolving methods for destroying and/or potentially using ventilation air methane. It presents the results of a technical evaluation of these technologies by the University of Utah (U of U). The report addresses energy conversion options to generate project revenues, and it contains an economic analysis of actual and hypothetical project configurations.

Technology Options

A project may use ventilation air methane as an ancillary fuel source to supplement the primary fuel. For example, a power plant or other combustion unit may use ventilation air (instead of ambient air) as combustion air. Ancillary projects usually would consume only a fraction of the available ventilation air. The report discusses the Appin project in Australia which uses ventilation air as combustion air in 54 internal combustion engines, each producing 1,000 kilowatts. This project is cost-effective, and one can expect to see more examples of ancillary ventilation air uses at other gassy mine settings.

A project may soon be able to use ventilation air as a principal fuel source (i.e., as the primary fuel that does not rely on a separate source of combustion) by using a flow-reversal reactor such as those described in this report. This application would consume up to 100 percent of the methane discharging from a single exhaust shaft. Two ventilation air methane processes identified in the report are:

- MEGTEC's VOCSIDIZER, a thermal flow-reversal reactor (TFRR), is in use at over 600 locations throughout the world primarily for destroying organic contaminants. Only one facility has operated exclusively on ventilation air, but about 200 other units use dilute natural gas as a support fuel to supplement concentrations of target compounds (e.g., industrial volatile organic compounds).

- The catalytic flow-reversal reactor (CFRR), developed expressly for mine ventilation air by Canadian Mineral and Energy Technologies (CANMET), is operating at bench scale (500 mm diameter and 30 $kW_{(t)}$) and will go into an industrial scale demonstration in 2000.

Technical Assessment of Flow-Reversal Reactors

Analysts at the U of U performed a technical assessment of TFRR and CFRR reactors using numerical modeling, and they were able to draw significant conclusions:

- Both technologies are technically able to oxidize dilute methane in ventilation air.

- Both technologies will produce useable energy from a heat exchanger operating at a useful temperature range.

- Based on laboratory and field experience, both the CFRR and the TFRR can sustain operation with ventilation air containing methane concentrations as low as 0.1 percent. Computer simulations performed for this report indicated that the CFRR and the TFRR remained stable at methane concentrations just above 0.1 and 0.35 percent, respectively. However, MEGTEC has observed that many of its TFRR units maintain bed stability at methane concentrations at about 0.15 percent, and MEGTEC supplied data that showed a unit exhibiting stable operation with a methane concentration as low as 0.08 percent. This result is consistent with MEGTEC's simulation modeling but contrary to the modeling performed for the U.S. Environmental Protection Agency (U.S. EPA) study. U.S. EPA acknowledges that computer simulations are no substitute for actual field observations.

- The lower limit of autothermal performance is an important parameter because it indicates the extent to which energy in ventilation air methane is recoverable or whether supplemental energy is required to sustain reactor operation.

These independent observations, coupled with the fact that flow-reversal reactors have operated successfully, give confidence that regenerative flow-reversal technology with or without a catalyst will achieve success during commercial-scale field trials combusting actual mine ventilation air methane.

Illustrative Economic Analyses

The report includes preliminary economic analyses of project scenarios using a flow-reversal reactor coupled to: (1) a gas turbine cogeneration facility or (2) a waste heat boiler. Both hypothetical projects appeared to be profitable when operating in appropriate energy markets, especially while taking advantage of modest carbon credits for the greenhouse gas emissions that the projects would mitigate. Economic assessments of ventilation air ancillary use projects also concluded that such projects can be economically viable with various types of power plants and primary fuels.

Because these economic studies were based on a series of assumptions and not actual field data, it is too early to rely on them with total confidence. They are a source of hope, however, that there are opportunities for economically eliminating methane emissions from ventilation air shafts.

1.0 INTRODUCTION AND BACKGROUND

This U.S. Environmental Protection Agency (U.S. EPA) report is a technical and economic assessment of existing and emerging processes for removing trace amounts of methane contained in ventilation air streams at gassy underground coal mines by converting that methane into useable energy.

Coalbed methane (CBM) is formed during the coalification process and resides within the coal seam and adjacent rock strata. Coal mining activity releases methane that has not been previously removed by drainage systems. The released methane then passes into mine workings and on to the atmosphere. Gassy underground mines release significant quantities of such methane, which is referred to as coal mine methane (CMM). When allowed to accumulate in mine workings, CMM presents a substantial danger of fire and explosion. Operators of gassy mines must remove methane to ensure miner safety and maintain continuous production.

Dilution by ventilation is the method most mine operators use to degasify air in the mine. Ventilation systems consist of inlet and exhaust shafts and powerful fans that move large volumes of air through the mine workings to maintain a safe working environment. Exhausted ventilation air contains very dilute levels of methane; typical concentrations range between 0.2 to 0.8 percent methane, well below explosive limits. To date (with few exceptions) ventilation systems release the air-methane mixture to the atmosphere without attempting to capture and use it. Operators may supplement ventilation with another form of degasification (i.e., methane drainage technology) which forcibly extracts methane from coal strata in advance of mining or from gob areas after mining.

Some operators capture and use drained CMM employing a variety of proven methods, but substantial quantities of drained CMM are also released to the atmosphere along with the ventilation air. Methane emissions from ventilation air comprise the largest portion of all CMM liberation worldwide, and they are the most difficult to use as an energy source. This report examines the current and future possibilities for destroying and potentially using ventilation air methane.

1.1 Global Importance of Ventilation Air Emissions

Methane is a potent greenhouse gas, approximately 21 times more effective than carbon dioxide in terms of causing global warming over a 100-year time frame. CMM emissions account for approximately 10 percent of anthropogenic methane emissions worldwide, and they are the fourth largest source of methane release in the United States. While there are no accurate data available measuring the relative quantity of CMM in ventilation air versus CMM in drainage systems worldwide, ventilation air is the much larger and more important producer. U.S. EPA estimates that ventilation systems emitted about 63 percent of all domestic CMM liberated in 1997.[1] Most other countries drain less and thus emit an even higher percentage of CMM. For example, in China ventilation systems release as much as 90 percent of total CMM liberated.[2]

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[1] U.S. EPA Report, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990¾1996*, EPA 236-R-99-003, April 1999.

[2] U.S. EPA Report, *Reducing Methane Emissions from Coal Mines in China: The Potential for Coalbed Methane Development*, EPA 430-R-96-005, July 1996.

Ventilation systems handle substantial air volumes. Consider this illustrative example: a single ventilation shaft that emits 2 mmcfd (56,650 m^3/d) methane at a concentration of 0.5 percent. The total flow of the air-methane mixture would be:

- 400 mmcfd (11.33 Mm^3/d)
- 16.67 mmcf/h (472 thousand m^3/h)
- 278,000 cfm (7,875 m^3/m)
- 4,630 cfs (131 m^3/s)

If the diameter of the ventilation fan outlet is 20 feet (6.1 meters), the air would move at a speed of 14.75 feet per second (4.5 meters per second).

As more mine operators install drainage systems or expand and improve existing systems, this vented-to-drained ratio will decrease, but the absolute volumes of vented methane will continue to be substantial. Therefore, an effective way to reduce CMM emissions would be to find methods to capture and use (e.g. generate electricity from) methane that exits the ventilation shaft.

1.2 Range of Emissions from U.S. Mine Ventilation Sources

This report identifies and assesses technologies that can be expected to handle the entire ventilation stream from a single shaft. A typical shaft at a gassy mine in the U.S. will move between 212,000 and 530,000 cubic feet per minute (cfm) or approximately 100 to 250 cubic meters of air per second (m^3/s). Ventilation exhaust air streams from gassy coal mines typically contain methane at concentrations ranging from 0.3 to 0.7 percent. This report gives information on a unit capacity of 212,000 cfm (100 m^3/s) which would be a practical modular size that mines could use singly or in multiples. A 212,000 cfm (100 m^3/s) ventilation flow containing 0.5 percent methane will emit 1.525 mmcfd or about 43,200 m^3 of methane per day.

1.3 Barriers to Current Recovery and Use

Ventilation airflows are very large, and the contained methane is so dilute that conventional combustion processes cannot oxidize it without supplemental fuel. Ventilation air's characteristics make it difficult to handle and process it into useable forms of energy, and thus constitute technical barriers to its recovery and use.

1.3.1 Technical Barrier 1: Large and Costly Air Handling Systems

Typical ventilation airflows are so great that a processing system will have to be large and expensive (see text box). Because the methane processing system will have to handle such large airflows without introducing resistance to the mine ventilation system, it will need to include a fan to neutralize whatever added resistance the reactor causes, thereby increasing the system's capital and operating cost.

1.3.2 Technical Barrier 2: Low Methane Concentrations

A methane-in-air mixture is explosive in a concentration range between approximately 4.5 and 15 percent. Below 4.5 percent, methane will not ignite or sustain combustion on its own without a constant ignition source, unless it can remain in an environment where temperatures exceed 1,832 ^{o}F (1,000 ^{o}C). Therefore, any conventional method proposed to use ventilation air as a fuel, or even to destroy it, would require a net energy input in addition to the fuel value of the methane contained in the ventilation air.

1.3.3 Technical Barrier 3: Variable Flows and Changing Locations

Even if the first two barriers could be overcome, mine operators will face the flow variations typically exhibited by a ventilation system. As mine operations progress underground, the working face tends to move away from the original ventilation shaft. A processing system built to accept a given flow will experience short-term periodic fluctuations and a probable decline over time as other, more distant exhaust shafts take over larger shares of CMM liberated during mining operations.

1.3.4 Institutional Barriers

When integrating systems that recover a fraction or all of the exhaust air with existing mine ventilation systems, designers will need to consider possible impacts on the ventilation system's effectiveness and take steps to maintain the mine's safety standards. To the extent that the recovery project demonstrably meets the requirements of mining regulations, mine management will be more likely to offer its cooperation in the venture.

1.3.5 Commercial Barrier

The major commercial barrier to ventilation air processing is that, under most situations, it cannot survive in a business-oriented marketplace without externally applied incentives. Any economically viable business will first exploit the resource that brings the most return, and marginal resources will only receive attention after the more accessible resources have been taken. The most marketable CMM commodity typically is pipeline-quality methane from undisturbed coal seams. The next fuel to be exploited is gob gas, a mixture of methane and air from gob drainage systems. Gob gas performs well as a substitute fuel in certain applications such as boilers, internal combustion engines, or gas turbines, and it can be upgraded for injection into natural gas pipelines. Ventilation air, the lowest quality gas byproduct of coal mining, has a negative value in the marketplace (except for its use as combustion air, explained below) because only one proven technology that uses its energy, ancillary use as combustion air, is field-proven at this writing. Developers will not fully exploit it until it can demonstrate a positive cash flow and an attractive internal rate of return.

1.4 Report Content

Section 2 of this report identifies and describes applicable ventilation air technologies, and Section 3 presents excerpts and a summary of the technical evaluation of these technologies by the University of Utah, Chemical Engineering and Fuels Department (U of U). (See Appendix A for a description of the U of U's numerical analysis.) Section 4 addresses energy conversion options to generate project revenues. Section 5 contains a comparative analysis of actual and hypothetical project configurations, which illustrate projects that developers might find attractive in various settings. This is followed by conclusions in Section 6. Appendix A contains U of U's technical evaluation; Appendix B presents the list of individuals who supplied information for this report; Appendix C samples some commercial gas turbines that could be applied to a vent air project; Appendix D presents a spread sheet model for allocating gob gas between the thermal reactor and a gas turbine; Appendix E shows cash flow models for several ventilation air methane use projects; and Appendix F summarizes recent CO_2 trading activities.

2.0 IDENTIFICATION OF APPLICABLE TECHNOLOGIES

This section examines some of the technologies that are available to mitigate ventilation air emissions and use the contained energy beneficially.

2.1 Demonstrated and Emerging Technologies

The technologies divide into two basic categories:

- Ancillary Uses - The focus of projects in this category is on a primary fuel that is <u>not</u> ventilation air methane; thus, employment of ventilation air is ancillary and restricted to amounts that are convenient for the project. For example, a power plant may use ventilation air (instead of ambient air) as combustion air in internal combustion (IC) engines, gas turbines, or other combustion units such as furnaces (collectively referred to as prime movers) that use CMM as primary fuel. Projects of this type normally use only a fraction of the ventilation air, but this report constructs a reasonable scenario wherein a large nearby power plant could consume the entire flow from one exhaust shaft.

- Principal Uses - Technologies in this category would use ventilation air methane as the primary fuel, without relying on a separate source of combustion, and would attempt to consume up to 100 percent of the methane emitting from a single exhaust shaft. As discussed below, these systems may also employ more concentrated fuels such as gob gas to enhance the utility or profitability of a given project.

2.2 Overview of Ancillary Use Technologies

All ancillary uses of ventilation air identified by U.S. EPA relate to its substitution for ambient air in the supply of combustion air in various prime movers. Oxygen in the combustion air combines with the primary fuel and the resulting combustion provides useful energy. The minor amounts of methane in ventilation air provide supplemental fuel for the combustion process along with necessary amounts of oxygen. The concept is simple, and it could find application at many gassy mines.

The technique requires a modest air handling and transport system that serves to bring ventilation air from the nearby ventilation shaft exit to the prime mover's air intake. The maximum distance between the shaft and the prime mover must be determined with a case-specific calculation that takes into account the physical site details and the economic benefit of the supplemental fuel represented by the methane in the ventilation air. In some cases the installation may require a booster fan to overcome pressure drops occurring in the transport ducting.

2.3 Ancillary Use Process Descriptions

Three distinct types of prime movers that would be candidates for such an innovation are combustion turbines, IC engines, and large boilers or furnaces.

2.3.1 <u>Combustion Turbines</u>

Combustion turbines, or gas turbines, draw in combustion air through a compressor, which is usually mounted on the same shaft as the turbine itself. After compression, the air passes through the combustor where the primary fuel and air ignite. If the combustion air were to contain useable fuel, the operator could cut back on the quantity of costly primary fuel used. U.S. EPA gathered information on this concept from four sources: a small development company, two combustion turbine manufacturers, and a U.S. Department of Energy (U.S. DOE) report.

Northwest Fuel Development.

Northwest Fuel Development of Lake Oswego, Oregon proved this concept experimentally in the early 1990s. The company synthesized a ventilation air flow with natural gas and ambient air and injected it into the combustion air intake of a small (225 kW) Solar Spartan gas turbine. The turbine's fuel flow governor automatically reduced primary fuel flow to compensate for the methane contained in the combustion air.[3]

Solar Turbines.

Solar Turbines, a division of Caterpillar Inc., has investigated this strategy for use with 3 to 8 MW turbines that would be located near mine ventilation shafts as the source of combustion air. Although the company has no long-term field experience with the technique, Solar engineers encourage its use in field applications, albeit within very strict methane concentration limits that they impose to guarantee the safe operation of the equipment. Solar participated in the U.S. DOE study described in the next section. Intake air in modern turbines functions both as combustion air and cooling air. If a customer were to use mine ventilation air with a Solar product, the company would insist that the mixture's methane content remain below one half of one percent to maintain the unit's cooling system. A richer mixture might cause several dangerous conditions (listed in the next section) in the interior of the rotor, which is the cooling-air path that keeps the turbine blades from overheating. Allowing even small amounts of methane in a turbine's intake air system is a complex issue, and Solar cautions that the company must review and approve all applications involving ventilation air substitution. A Solar engineer[4] explained that each turbine model operating with any given combination of operating parameters will result in a different percentage of intake air that actually goes through the combustor (thus consuming the methane). Operating variables that affect this percentage include pressure, temperature, low-NOx or standard model turbine, and excess air ratio. He estimated that the ratio of methane destroyed (and converted to energy) to the total quantity taken in might be as low as 20 percent and as high as 60 percent. For preliminary planning purposes, one could expect that the fuel contribution supplied by a ventilation air stream containing 0.5 percent methane might amount to about 10 percent of the turbine's fuel needs.

U.S. DOE Report.

U.S. DOE published a report entitled "Utilization of Coal Mine Ventilation Exhaust as Combustion Air in Gas-Fired Turbines for Electric and/or Mechanical Power Generation" in 1995.[5] The Phase 1 report contains an analysis of the opportunities and limitations of introducing ventilation air methane into the compressor of a Solar gas turbine, Centaur 40 model. The study team included a Solar research engineer, representatives from the coal

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[3] Personal communication with Mr. Peet Soot of Northwest Fuel Development, May 1999.
[4] Personal communications with Mr. Mohan Sood of Solar Turbines, March 1998.
[5] U.S. DOE Topical Report, *Utilization of Coal Mine Ventilation Exhaust as Combustion Air in Gas-Fired Turbines for Electric and/or Mechanical Power Generation*, Contract No. DAC21-95MC32183, December 1995.

mining division of Jim Walter Resources, Inc., research scientists from the University of Alabama, and other experts. Following are some of the report's major findings:

- The study team limited itself to a methane concentration of one half of one percent in the ventilation air because larger concentrations would diminish the cooling performance of the ventilation air by creating autoignition inside the rotor. Autoignition occurs when water in the saturated ventilation air reacts with methane in the presence of nickel alloys, forming combustible amounts of hydrogen and carbon monoxide (CO). This mixture autoignites, probably in less than 1 millisecond, and causes an increase in turbine internal and exit temperatures. Further research is needed to determine how severely this phenomenon will affect turbine operation.

- The CO is unlikely to ignite in the rotor if inlet methane concentrations remain below one half of one percent. Therefore, the turbine will emit increased amounts of CO plus unburned hydrocarbons. Such increased emissions may require one of the following additions to the facility design:
  - Cogeneration. A supplementary-fired heat recovery steam generator (HRSG) producing steam as a byproduct of the plant.
  - Combined cycle. A supplementary-fired HRSG coupled to a steam turbine-generator to produce additional electric power.
  - Post-combustion control. A catalytic oxidation system.

- If there is a possibility that ventilation air might contain more than one-half of one percent methane, the facility will need an additional inlet for ambient air with controls to keep the mixture at the desired concentration.

- A fraction of the ventilation air is used to pressurize the oil return system by forcing the oil leaving the engine bearings back to the oil sump. Methane dissolves in most oils and has a deleterious effect on lubricity. Thus, special gas stripper systems would be used to remove the dissolved methane. The exhausted methane may form an explosive mixture, requiring flame traps to ensure against ignition.

- A commercial wet scrubber should be used ahead of the gas turbine to eliminate the coal fines usually found in the saturated ventilation air.

- The fraction of fuel provided by ventilation air methane is a function of the purity of methane in the primary fuel. In the Centaur 40, when gob gas with 80 percent methane is the primary fuel the ventilation air supplies about 12 percent of the fuel mix. With 100 percent methane the fraction moves down to about 10 percent.

- The team studied how they could raise the ventilation air methane to the maximum practical fraction to conserve the cost of the primary fuel. They achieved a (calculated) 55 percent contribution from ventilation air methane by decreasing the gob gas flow. This had the effect of lowering the turbine rotor inlet temperature (TRIT) to 1450 ^{o}F from 1660 ^{o}F. The lower temperature protects the rotor from effects described above, but it derates the turbine from 3.415 MW to 2.5 MW. This approach was not economically feasible because the small dollar value saved in gob gas cost was less than the value that was lost as a result of decreased production. The team calculated the effect of an intercooled recuperative (ICR) cycle which raised the calculated ventilation air methane contribution to 62 percent. This was a costly option because an ICR requires a higher capital investment while earning marginal savings in fuel cost. The team even speculated on a specially-designed gas turbine which could operate solely on methane concentrations in the range of 1.4 to 2 percent. One of the several features to be employed by such a design would be an externally plumbed, fresh-air cooling system.

The team has proposed a Phase 2 program which will design, construct, and operate test facilities based on the calculations and conclusions from Phase 1.

GE Stewart Stevenson.

U.S. EPA made similar inquiries to GE Stewart Stevenson, a manufacturer of much larger combustion turbines[6] used for commercial power systems. That company maintains strict limits on any contaminants in the combustion air stream. Engineers from GE Stewart Stevenson said that they might review and possibly relax those limits to take advantage of the fuel values in mine ventilation air only if a client paid for the research necessary to assure system integrity.

2.3.2 Internal Combustion Engines

IC 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. IC engines are good candidates for beneficially using part of a ventilation air stream by substituting it for fresh ambient air in the combustion air intake. BHP Collieries Division has proved this concept by using ventilation air as combustion air in 54 one-megawatt Caterpillar 3516 spark-fired units at the Appin Colliery in Australia. 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.

Demonstrating a Partial Use of Ventilation Air Methane

At the Appin Colliery, BHP in Australia successfully proved that ventilation air may be substituted for combustion air in internal combustion engines:

- *54 one-MW CAT 3516 engines.*
- *Primary fuel is drained coal mine methane.*
- *Ventilation air is 0.3 to 0.7 percent methane and contributes between 4 and 10 percent of engine fuel.*
- *Consumes on the order of 20 percent of ventilation emissions.*

The project's unique feature is that combustion air for each engine located at Appin is supplied by mine ventilation air, which until recently averaged about 0.7 percent methane. Due to improved CMM drainage and increased flow through the fans, the methane concentration will fall to 0.3 percent or below. There are no fans in the ductwork taking ventilation air to the engines because the turbochargers on each engine have sufficient suction power to overcome,

[6] Personal communication with senior advanced turbine engineer, GE Stewart Stevenson, a General Electric gas turbine packager, May 1999.

without noticeable loss of engine performance, the 0.58 psig (4 kPa) pressure loss through the ducts and air scrubbing and filtering system.

The inlet to the duct is a free collection hood mounted about 5 feet (1.5m) above the discharge of the mine ventilation fan. The reasons for this configuration are:

- To eliminate back-pressure on the ventilation fan, even when the engines are not taking any air. This was confirmed by testing.

- To keep the duct (and by inference the IC engine power station) separate from the mine ventilation system so they are not under the jurisdiction of mine inspectors.

The fuel value contributed by this air stream peaked at about 10 percent of each engine's fuel needs during the early years, but this contribution has fallen to near 3 percent recently. Since the project must rely on natural gas to supplement its primary fuel during periods of low CMM availability, the methane from ventilation air represents a significant cost savings on purchased fuel.[7, 8, 9] To regulate the fuel needed by the engines, the project uses an electronic control system that balances the volume of drained CMM, ventilation air methane, and natural gas.

Further details on this project's commercial and economic aspects are presented in Section 5 of this report. Figure 1 is a schematic diagram of the Appin project.

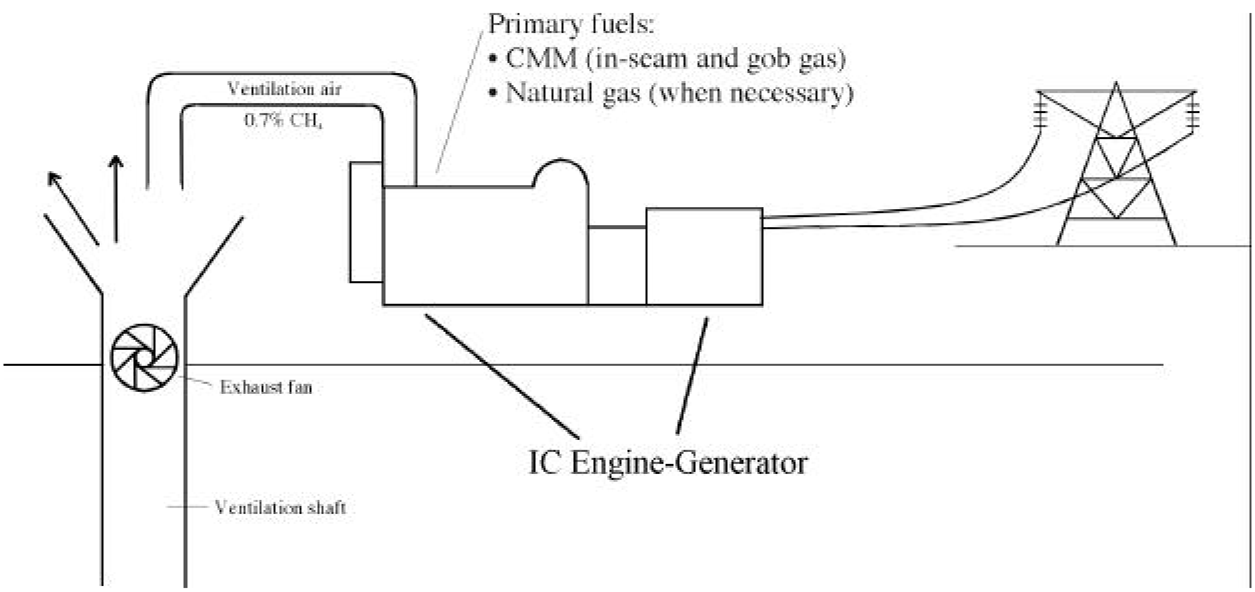

Figure 1. Schematic Flow Diagram of the Appin Project

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[7] *State of the Art Power System Converts Methane to Energy at Australian Coal Mines*, paper given by L.D. Lloyd, Caterpillar, Inc., Lafayette, IN, at the U.S. EPA Conference in Pittsburgh, PA "Marketing Your Coal Mine Methane Resource", April 9, 1998.

[8] Personal communications from Geoff Bray, former Project Engineer with BHP Engineering, December 1998 and October 1999.

[9] *The Appin and Tower Collieries Methane Energy Project*, a BHP Engineering Pty. Ltd. report provided by Geoff Bray, Project Engineer, on September 26, 1998.

2.3.3 *Other Ancillary Uses*

If ventilation air could be delivered to a large fuel consumer such as a coal-fired power boiler or a brick kiln located near the ventilation air source (e.g., within approximately 500 yards or 450 m), it could readily replace ambient air for all or part of the combustion air requirements. For example, a ventilation shaft emitting 2 mmcfd (56,640 m^3/d) of methane could supply enough combustion air for a mine-mouth, coal-fired power plant rated at approximately 125 MW. This technique is technically feasible, especially if the plant already exists or will soon be built near a mine ventilation shaft. Powercoal, an energy company in Australia, is considering a direct interconnection between mine ventilation fans and forced draft fans at an existing adjacent coal-fired power plant. For a new plant, however, a power developer must assess the likelihood of an adequate supply of ancillary fuel over the economic life of the plant. Section 5 presents an economic analysis of an illustrative case featuring a 125 MW coal plant.

2.3.4 *Summary of Ancillary Uses*

This investigation has revealed that, within certain limits, it is technically feasible to use ventilation air as combustion air in a variety of energy facilities such as combustion turbines, IC engines, and large furnaces and boilers. In fact the concept is quite simple and its application is straightforward.

- Small-scale experiments have shown that combustion air substitution in gas turbines is technically feasible. Technical investigations are needed (1) to ascertain the limits of methane intake with a small gas turbine application, and (2) to demonstrate the concept with large gas turbines.

- Combustion air substitution is technically feasible, state-of-the-art, and commercially demonstrated with IC engines.

These ancillary uses exhibit a common pattern, including:

- All processes require a separate energy source, the primary fuel, to generate the temperatures needed to combust dilute methane in the ventilation air.

- The air handling and transport system needed to bring ventilation air to the prime mover's air intake is not costly if the facility is reasonably close to the exhaust shaft. For example, Caterpillar reports that the system at the Appin Colliery represented a small percentage of the capital cost of the entire plant. Unless the transport distance is long, requiring booster fans with significant power demands, there will be little operational cost associated with ventilation air use.

- The technique benefits users of costly primary fuels by reducing fuel purchases on the order of 8 to 10 percent.

- The technique allows users of gob gas, an inexpensive primary fuel, to produce more power than would otherwise be possible.

- Applications using small gas turbines and IC engines reduce methane emissions by as much as 20 percent of a mine ventilation shaft's output, while large coal plants may accept up to 100 percent.

2.4 Principal Use Technologies

The search for principal use technologies, defined as those technologies that can combust dilute methane in ventilation air as a primary fuel without reliance on another source of combustion, yielded two processes:

- A thermal flow-reversal reactor (TFRR) process, offered by MEGTEC Systems, a subsidiary of Sequa Corporation, a U.S. company.

- A catalytic oxidation process called the Catalytic Flow-Reversal Reactor (CFRR), developed by a consortium of Canadian interests including CANMET.

A description of each system and its development status follows.

2.4.1 Thermal Flow-Reversal Reactor

History.

MEGTEC Systems[10] offers the VOCSIDIZER, a TFRR that operates above the autoignition temperature of methane (i.e., above 1832^o F (1000^o C)). It is a modification of a commercially proven process for the thermal oxidation of volatile organic compounds (VOCs). MEGTEC has over 600 of these TFRR installations in a variety of applications for VOCs and odor emission reduction. For example, a large (116,500 cfm or 55 m^3/s) TFRR unit for VOCs oxidation operates at the Volvo plant in Gothenburg, Sweden. Such a unit would have about half the capacity required to process air from a small to medium-sized mine ventilation shaft. This unit operates on a mixture of injected methane (in the form of natural gas) and paint solvents during periods when solvent concentrations fall below the limit required for self-sustained operation. Many other MEGTEC installations also are capable of injecting methane to assure stability.

In addition, MEGTEC reported that a 6,350 cfm (3 m^3/s) demonstration TFRR unit operated at a British Coal mine site for a period of six months. The company learned that the unit effectively destroyed methane in a partial flow withdrawn from the mine ventilation exhaust. Detailed information from those trials is not available at this time.

Description.

Figure 2 shows a schematic of the TFRR reactor. This is a simple apparatus that consists of a large bed of silica gravel or ceramic heat exchange medium with a set of electric heating elements in the center. Airflow equipment such as plenums, ducts, valves, and insulation elements are fitted around and within the bed. Controls and ancillary equipment are mounted nearby.

[10] MEGTEC is a De Pere, Wisconsin-based subsidiary of Sequa Corporation. The VOCSIDIZER was developed by ADTEC of Sweden, which now is a part of MEGTEC.

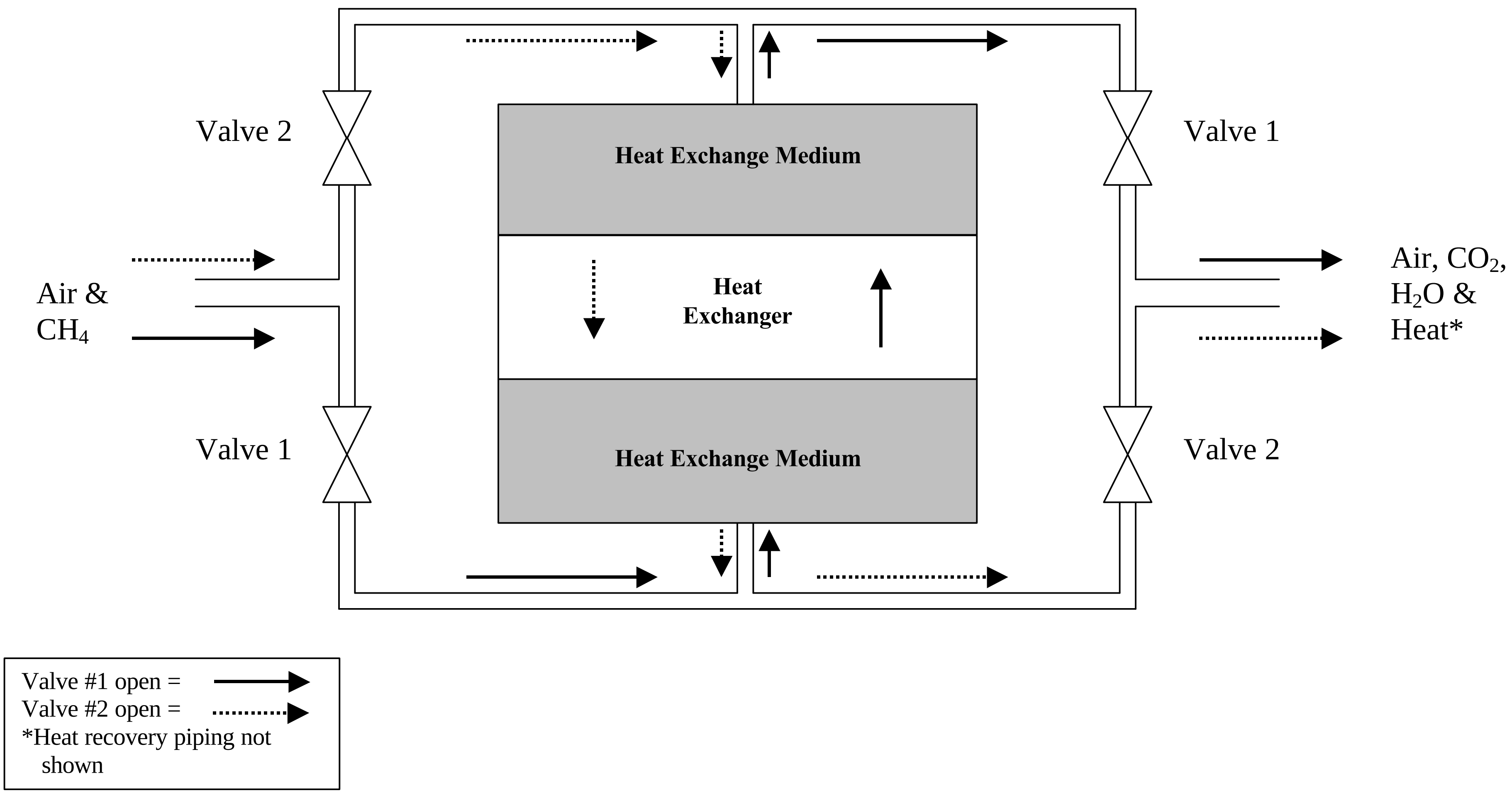

Figure 2. Schematic of Thermal Flow-Reversal Reactor (TFRR)

Principles of Operation.

The process employs the principle of regenerative heat exchange between a gas (ventilation air) and a solid (bed of heat exchange medium selected to store and transfer heat efficiently) in the reaction zone. In Figure 4 the ventilation air enters from the left and leaves at the right during the entire operation. One cycle of the process is comprised of two flow reversals, so each flow reversal is a half-cycle. Referring to Figure 4, assume that during the first half-cycle both valves number 1 are open while valves number 2 are closed. Thus, the flow through the reactor takes place from bottom to top. After a time interval determined by the reactor's temperature profile, the reactor reverses flow direction by closing valves 1 and opening valves 2. Flow then takes place from top to bottom.

To start the operation, electric heating elements preheat the middle of the bed to the temperature required to initiate combustion (i.e., ≥1832^o F (1000^o C)). During the first half of the first cycle, ventilation air at ambient temperature enters and flows through the reactor in one direction. Methane oxidation takes place near the center of the bed when the mixture exceeds the combustion temperature of methane. If that temperature can be maintained in the bed, practically 100 percent conversion of methane (to carbon dioxide and water) can be achieved.

If the gas is not heated to the autoignition temperature of methane, the reaction will not start. Because such a condition provides no heat source, the preheated solids are slowly cooled by the incoming gas. The gas temperature rises at first and then drops slowly until both solid and gas are at the feed gas temperature. The process thus ends at the first half-cycle. This situation is called a *non-starter*.

Even if the reaction does start, the final conversion must be complete enough to cause a sufficient temperature rise that will heat the gas in the next cycle to the autoignition temperature. Otherwise, the behavior exhibited by the reactor in the first half-cycle of a non-starter is again observed, but over a number of cycles. This situation is called a *blow-out*.

After the initial cycles, hot products of combustion and unreacted air continue through the bed, losing heat to the far side of the bed in the process. When the far side of the bed is sufficiently hot and the near side has cooled, the reactor automatically reverses the direction of ventilation airflow. New ventilation air enters the far side of the bed and becomes hotter by taking heat from the bed. Close to the reactor's center the methane reaches autoignition temperature, oxidizes, and produces heat to be transferred to the near side of the bed before exiting. Temperature at the core reaches 1832^o F (1000^o C) plus the adiabatic temperature rise, and then decreases as the heat exchanger removes heat from the unit. The details of flow reversal are discussed in the following paragraphs.

In an ideal situation the temperature profile in the bed would be as shown in Figure 3. When the ventilation air flows from the bottom of the chamber to the top it picks up heat from contact with the hot solid media, and its temperature increases. The gas temperature lags the solid temperature by a few degrees both while gaining and losing heat. MEGTEC indicates that this gas-to-solid lag has been between about 20^o C to 50^o C in existing units. As the flow continues in the initial half-cycle, the temperature hot zone, with respect to both the solid and the gas, tends to migrate upward (for the bottom-to-top illustrative flow configuration). The flow reversal arrests this upward migration and prevents it from traveling too far from the center. The next half-cycle flow (top-to-bottom) produces a new temperature profile, also shown in Figure 3. By switching flow direction at precalculated and preset time periods, typically about 120 seconds, the hot zone can be maintained in the center of the reactor. MEGTEC prefers to keep a short cycle time so that the location of the maximum bed temperature shifts only a short distance up and down while the profile maintains its shape.

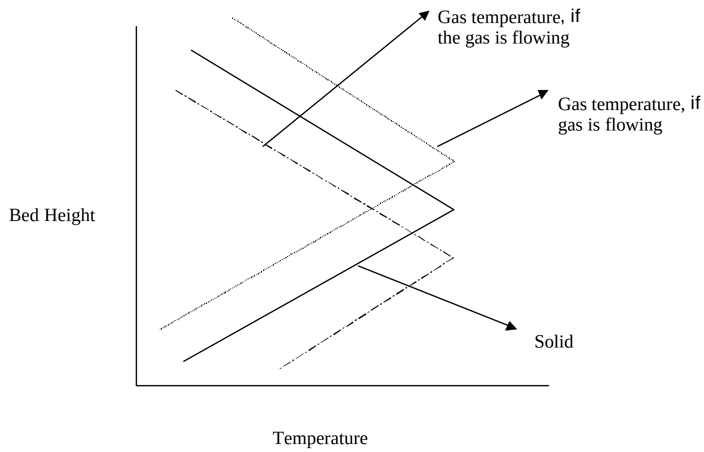

Figure 3. Illustrative Ideal Temperature Profiles in TFRR

Figure 3 shows that, even with very efficient heat transfer, the exit air temperature is at least a few degrees higher than the incoming ventilation air. As a result, if no energy is generating internally, the bed would eventually cool. MEGTEC claims that if the methane concentration in the incoming air is consistently 0.15 percent or more, and if the unit has been optimized to meet that parameter, the operation will be autothermic (i.e., it will support itself without additional applied heat or fuel). This would mean that oxidizing this quantity of methane will produce enough heat to compensate for an approximate 72^{o}F (40^{o}C) temperature rise in the exit gas flow (relative to incoming gas temperature), which represents a heat loss from the process. It also is a measure of the efficiency of the heat exchange between gas and solid. The company claims that other heat losses from the reactor are negligible. To substantiate its statements, the company provided data on a unit operating in the field. During typical weekends there are no product emissions to be destroyed, so the operator sustains the reactor by injecting natural gas. The submitted data showed that this unit can sustain operation by maintaining the core temperature just above the autoignition temperature of methane with a methane concentration of approximately 0.08 percent. One of the objectives of the technical assessments and numerical modeling described in Section 3 and Appendix A is to duplicate independently the phenomena that MEGTEC describes as field experience.

Heat Recovery.

If the methane concentration in ventilation air exceeds the level necessary for self-sustained operation, the process can recover high-quality heat and still maintain a steady-state operation.

Figure 4 shows the cyclic steady-state solid temperature profile of the bed in an ideal operation with heat recovery.

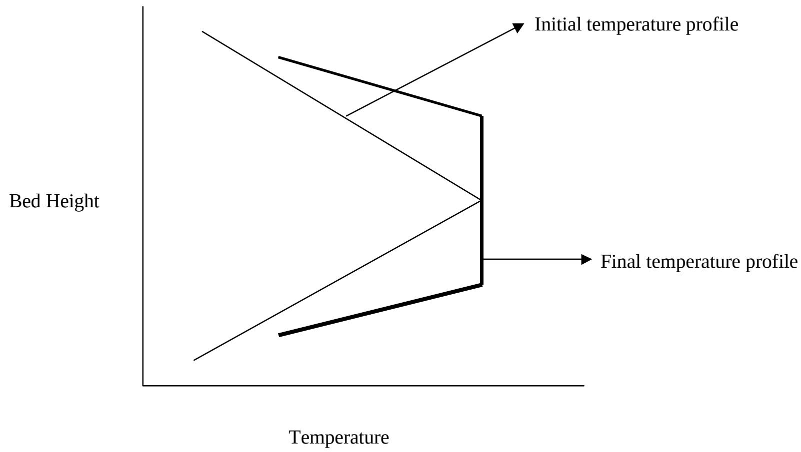

Figure 4. Illustrative Ideal Heat Exchange Medium Bed Temperature Profiles in TFRR

If the reactor has sufficient methane to reach thermal equilibrium, its exhaust gas temperature will be raised by a value equal to the adiabatic temperature increase in the reactor. The temperature reached depends only on the inlet methane concentration.

> *Adiabatic temperature rise is defined as the temperature differential between the reactants and products assuming there is no external heat exchange and that all of the heat of reaction goes toward increasing the temperature of the products.*

There are three different methods of excess heat removal, depending on the amount of excess heat to be recovered and the specific application.

- Heat can be recovered from exhaust gases exiting the reactor. However, this heat will not be of high quality because the exit gas temperature will be much lower than that of the gas as it passes through the combustion zone. For example, the adiabatic temperature increase for one-percent methane would be about 477^{o} F (265 ^{o}C), 0.5 percent methane would be about 239^{o} F (133 ^{o}C), and 0.1 percent methane would be about 43^{o} F (24^{o} C).

- The second method for recovering heat is by inserting heat transfer coils (containing air, water, or other media) into the hot zones of the reactor and recovering a much higher-quality heat (e.g., 700^{o} C to 800^{o} C). The technical review of energy recovery methods in Sections 4 and 5 of this report concentrates on this more practical, high-temperature heat exchange method. One example is the use of compressed air from a gas turbine's compressor as the heat sink for the reactor. The heated, compressed air returns to the turbine, expands through the turbine blades, and produces power. Another example is the use of water as the heat transfer medium to produce steam.

- The third method is to use part of the gas at its highest temperature directly for heat transfer and to let the remaining part pass through the system. This recovery technique will be the most complicated of the three.

Commercial Status.

Although MEGTEC has been marketing its TFRR for use at gassy mines for several years, the company has not installed a commercial-scale demonstration unit. {Note: The capacity of the unit used for the British Coal trial was only 6,350 cfm (3m^3/second).} However, they intend to increase their marketing efforts to establish a demonstration plant at an operating mine.

2.4.2 Catalytic Flow-Reversal Reactor

History.

In 1995 researchers at Energy Diversification Research Laboratory/Natural Resources Canada (EDRL/NRCan) in Varennes, Quebec (also known as Canadian Mineral and Energy Technologies or CANMET) conceived of and developed the Catalytic Flow-Reversal Reactor (CFRR) expressly for use on coal mine ventilation air methane. The research team was well aware of thermal flow-reversal reactor technology and its use in other applications, but they desired to improve the TFRR so that it could process mine ventilation air at lower temperatures. As a result of this research, CANMET selected a catalyst that reduces the autoignition temperature of methane by several hundred degrees Celsius. The CFRR technology development has included demonstration of the concept over a range of simulated conditions at small scale. CANMET and several Canadian private and government entities have formed a consortium to finance, design, build, and operate an industrial-scale demonstration plant (approximately 16,900 to 21,200 cfm (8 to 10 m^3/s)) at a mine in Nova Scotia. CANMET is also studying energy recovery options that are appropriate for the CFRR, especially the gas turbine option.

Description. The CFRR has the same basic design and operation as the TFRR described above. Figure 5, a schematic of the process, shows that the reactor has three sections. The sections at the two ends of the bed are packed beds of inert materials. During "top-to-bottom" flow, the top section provides heat to the incoming ventilation air and raises it to a temperature at which combustion in the presence of a catalyst will commence in the center section. As hot products of combustion pass into the bottom section, their heat transfers to the bed, raising its temperature. The section housing the reactor and the heat exchanger lies between the two inert beds and contains catalyst pellets. All three sections of the reactor are well-insulated so that little heat is lost to the surroundings.

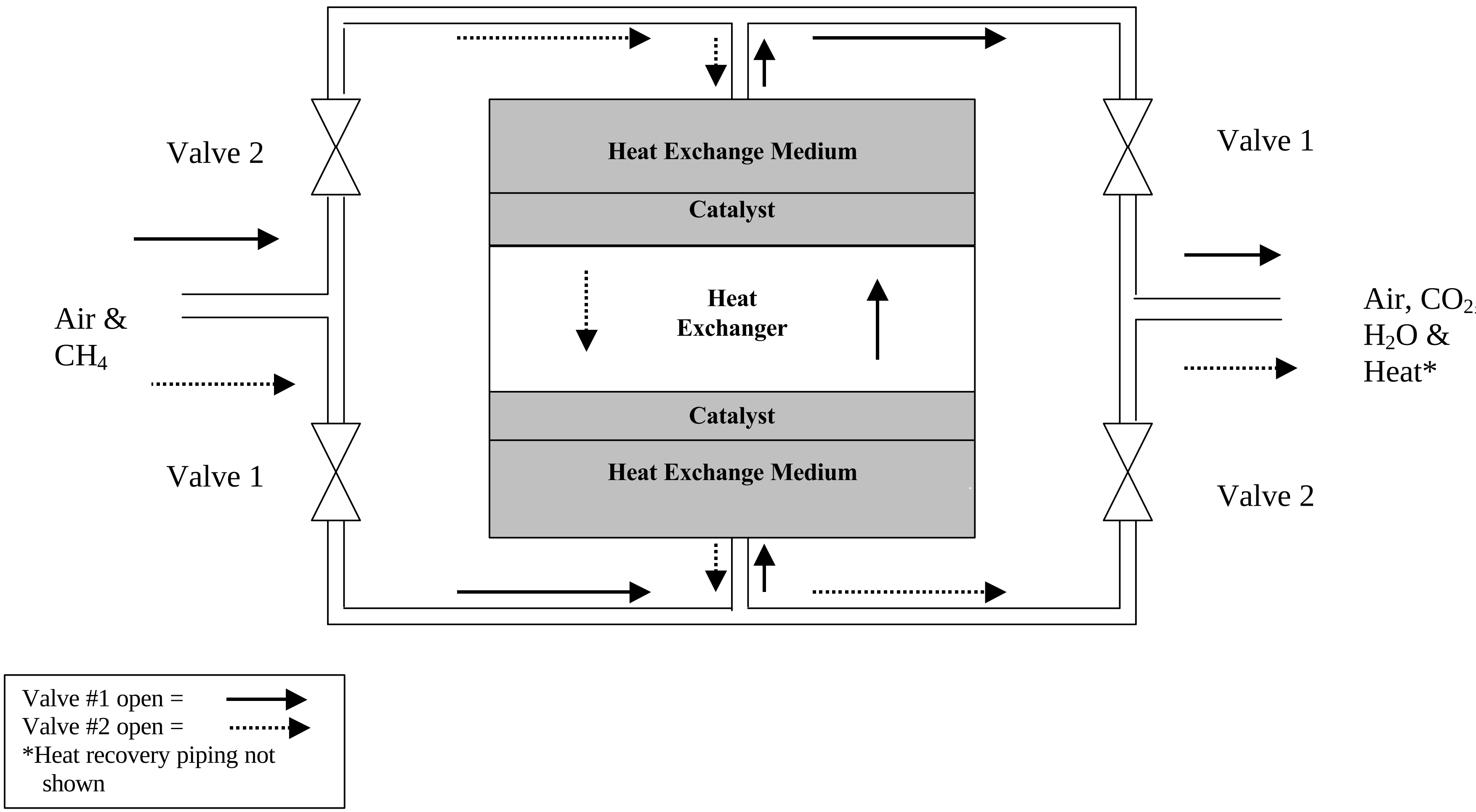

Figure 5. Schematic of Catalytic Flow-Reversal Reactor (CFRR)

Principles of Operation.

CFRR's operating principal is identical to that of its thermal counterpart except that the reaction is catalytic and therefore takes place at much lower temperatures. The advantages of this process are discussed in the technology assessment below. They include a more stable reaction and longer cycle times.

Heat Recovery.

Heat recovery options and operating principles for the CFRR are identical to those discussed above for the TFRR. There are differences in the method of heat transfer and quality of heat recovered from the two systems, however (see discussion in Section 4). CANMET has experimental evidence of heat recovery between 50 and 90 percent of the input heat value of the methane.

Commercial Status.

The Canadian consortium that will demonstrate the CFRR at industrial scale hopes to have the unit operating at a mine site in Nova Scotia in 2000. Once success of this unit has been demonstrated, the group will commence active marketing to the coal mining and energy industries.

2.4.3 Summary of Principal Uses

Investigation for this report revealed two systems that may be suited for capturing, destroying, and using the energy from dilute methane contained in mine ventilation air. Both the TFRR and CFRR employ the flow-reversal principle to transfer methane's heat of combustion, first to a solid medium, and then back to incoming air to raise its temperature to the ignition temperature of methane. Both system vendors affirm that NO_x emissions from their units are low. CO emissions will probably be low as well because combustion takes place in a high excess air environment, but the vendors did not comment on this. The two systems differ only with respect to the use of a catalyst. The CFRR uses a catalyst to reduce methane's combustion temperature.

The following factors give some encouragement to the future of mitigating ventilation air methane emissions with flow-reversal reactors:

- There are over 600 TFRR units operating in the field, most of them serving to destroy harmful organic emissions. According to MEGTEC, one unit has operated with mine ventilation air as its primary fuel, and several other units use injected methane to sustain operation.

- Some TFRR installations recover and use excess heat by employing heat exchangers embedded in the reactor. MEGTEC states that these heat exchangers do not upset the stability of the temperature profile. The company is unable to disclose further design details because of confidentiality issues.

- The CFRR, designed and tested exclusively for use with coal mine ventilation air, has fully demonstrated its ability to combust a wide range of input conditions in laboratory trials. CANMET has collected comprehensive data showing that the unit operates with methane concentrations as low as 0.1 percent and recovers high fractions of available heat. The laboratory has correlated its experimental data with results predicted by a sophisticated computer modeling program.

- CANMET also tested the CFRR in an actual mine ventilation air environment at the Phalen Mine in Nova Scotia. After exposing a unit with its catalyst to mine exhaust for four months, CANMET found no deterioration of the catalyst beyond the normal decay that they had observed in the laboratory. This trial proved that dust carried by the ventilation air had no adverse effect on the unit, and it confirmed the previous findings on expectations for catalyst life.

- MEGTEC has presented evidence that a TFRR unit operating in the field routinely operates with methane concentrations as low as 0.08 percent.

- Both the TFRR and the CFRR will be able to withstand temporary interruptions in the feed stream because of their considerable thermal capacity. CANMET operated the CFRR on a 0.5 percent methane feed stream and allowed the core temperature to rise well above autoignition temperature (in the presence of a catalyst). They then shut off the feed stream and monitored the slowly declining core temperature until it reached the autoignition limit 17 hours later. This phenomenon will bring practical benefits to field applications during periods of equipment maintenance or mine ventilation changes.

- Both MEGTEC and CANMET are confident that they can build reactor modules in sizes large enough to capture and process most or all of the airflow from a typical mine ventilation shaft with a small number of modules.

Table 1 presents some of the significant differences and similarities between the two technologies.

Table 1. Summary of Differences and Similarities Between the TFRR and the CFRR

Feature	***TFRR***	***CFRR***
Principles of operation	Same	Same
Catalyst	No	Yes
Autoignition temperature	1832^o F (1000 ^{o}C)	662^o F to 1472^o F (350 ^{o}C to 800 ^{o}C)
Experience	600+ units in field, some operating on methane	Bench scale trials with simulated mine exhaust
Cycle period length	Shorter	Longer
NO_x and CO emissions	Low	Low

Sections 3, 4, and 5 of this report address three remaining issues related to the viability of flow-reversal technology for destroying methane in mine ventilation air: confirming technical feasibility of the reactors, integrating energy recovery technology, and assessing cost effectiveness.

2.5 Technical Considerations in Adapting Air Handling Systems to Mine Ventilation Facilities

Mine ventilation systems for gassy coal mines are typically equipped with large above-ground exhaust fan installations. The majority of mines use exhausting ventilation fans rather than forcing fans. As previously mentioned, a system designer who integrates an existing ventilation system with a processing facility that recovers all or a fraction of the exhaust air will need to consider impacts on the mine's ventilation system and take steps to maintain the mine's safety standards. The recovery project must meet the requirements of both mine management and mining regulatory authorities.

2.5.1 Impacts on Mine Ventilation System

Whether designers recover the ventilation air from passive air ducts installed directly into the fan's discharge evasé (cone shaped discharge plenum) or through ducts connected on the outby or inby sides of the mine's fan, engineers should ensure that the performance characteristics of the integrated system, with respect to total pressure and airflow, are similar to that of the mine's original design. Ducts installed in an evasé increase system resistance, and air splits located inby or outby the fan disturb flow paths and increase air turbulence. Therefore, all recovery configurations will increase fan operating pressures unless the system introduces a negative pressure from downstream, and that must be a requirement for every project. Aerodynamically designed installations will minimize resistance and shock losses attributed to ventilation air collection infrastructure.

2.5.2 Integration With Fans Operating Within Oxidizer Systems

Inby locations.

A ventilation methane oxidizer may be equipped with a fan operating at total mine pressure and configured to recover ventilation air inby the main mine fan. Mining authorities will consider such an active facility to be an integral part of the mine's ventilation system, and they will subject such facilities to the same coal mine safety guidelines applicable to main mine fans. Depending on the country of operation, these regulations may stipulate permissible in-line electric motors, incombustible ducting, monitoring systems and alarms, independent power supply, backup motor (non-electric) or fan, explosion force relief provisions, and incombustible fan isolation doors.

Outby locations.

To facilitate approval and application, the authors recommend that the methane recovery facilities contemplated in this report recover ventilation air outby main mine fans. With this configuration, mining authorities will likely only stipulate the permissibility requirements (e.g., permissible in-line electric motors, monitoring system with alarm, and incombustible ducting). For all ventilation air recovery systems contemplated, designers will need to assure regulators that the methane recovery system, and any secondary energy recovery circuit, such as a gas turbine, will not produce explosive methane-and-air mixtures. The design should also ensure that if a deflagration in the methane recovery or secondary energy recovery circuit were to occur, sufficient safety measures are in place to isolate these facilities from the mine's ventilation system. Designers should also make clear to the mine operators and the regulators that the recovery system will incorporate its own air transport system for the oxidizer and will not burden the existing ventilation system.

3.0 TECHNICAL EVALUATIONS

The University of Utah (U of U) prepared a technical assessment of the TFRR and CFRR chemical reactor processes using computer simulation techniques. The following discussion summarizes their methodology and outlines their findings. Appendix A provides details on the numerical simulation models developed to perform the technical assessments and presents the quantitative results.

3.1 Numerical Modeling

3.1.1 Assessment Methodology

In this assessment, the U of U developed and used a numerical computer model. Numerical reactor models are widely used tools that simulate chemical reactors and assess their technical feasibility. To build the model, the analyst first describes the physical phenomena occurring in the reactors and then writes mathematical descriptions of each. Generally, several simplifying assumptions are necessary prior to expressing the physical system in its mathematical form so that the mathematical equations are computationally amenable. The model solves those equations, usually differential equations, using appropriate boundary conditions. Models are useful for providing design guidelines and later for optimizing reactor performance. In the current context, the models simply tested the feasibility and displayed operating characteristics of the two processes.

The U of U created the model and modified it for each of the two reactors. The models did not incorporate a heat recovery section since this component of the process depends heavily on site-specific choices for the most appropriate heat recovery method. Some of the necessary design parameters were not furnished by the system suppliers because such information is case specific, not yet available, or proprietary. However, by working with the vendors and making reasonable assumptions based on similar processes found in the literature, the analysts at U of U were able to select a reasonable range of physical parameters to employ in the model. These parameters include reactor configuration, types of materials, voidage (which is a measure of bed porosity), pressure drops, velocities, and temperature profiles.

3.1.2 Thermal Flow-Reversal Reactor

The process modeling showed that the TFRR oxidizer is a feasible option for utilizing the methane available in coal mine ventilation air. The TFRR operation is stable for a properly chosen set of design parameters and operating conditions.

Initially, the reactor is hot in the middle with the temperature tapering off at either end. The initiation temperature at the center is on the order of 1832 ^oF (1000 ^oC). The ventilation air enters the reactor at room temperature. As the operation proceeds, the temperature of the exhaust gases increases by the adiabatic temperature rise. If the exhaust reaches unacceptably high levels, heat recovery may be essential. The U of U’s observations on the TFRR simulation are summarized below:

- Below 0.35 percent methane the simulation calculations indicated that blow-out would occur. This result goes counter to MEGTEC statements (and the results of its own computer simulations) that the unit will continue to function at concentrations of 0.08 methane. The company confirmed this claim by submitting data on a unit that operates in the field destroying organic odors during weekdays only. Because there are no product emissions during weekends to sustain temperatures in the reactor, the operator injects methane into the airflow to prevent blow-out. The data show that the average methane concentration during this period was about 0.08 percent while the reactor core temperatures remained at just above 1000° C.[11]

- While operating in the expected range of ventilation air methane concentrations (e.g., 0.4 to 0.6 percent methane), the U of U's TFRR simulations were stable.

- The energy required to bring the reactor to methane combustion temperature is substantial, but since start-up should be an infrequent occurrence, it is insignificant when spread over a project's life-cycle.

The U of U concludes that the TFRR, operating on a steady supply of ventilation air methane at concentrations typically encountered in the field, is a technically feasible process for oxidizing methane. Uncertainty arises when the concentrations approach the level at which blow-outs occurred during simulation trials. Mathematical models are inherently limited by the physical phenomena that they represent. The model in this study incorporated all of the logical physical phenomena in the transport and reaction of ventilation air in these reactors. Even with the state-of-the-art mathematical representation, however, models only approximate physical reality. While the model predicts blow-out below 0.35 percent methane, MEGTEC affirms that its own model shows that the process continues to be autothermal even below 0.1 percent methane. The researchers at U of U concede that under certain reactor configurations and with different design parameters it may be possible to lower the methane concentration bound at which the TFRR operates autothermally.

More persuasive in terms of assessing stability at low methane concentrations, however, are the reports from the field. According to MEGTEC, over 200 operators of their TFRR units regularly add natural gas to industrial airflows, just as in the case cited above. These airflows temporarily contain low levels of combustible material and would otherwise blow out. MEGTEC reports that these injections produce methane concentrations similar to those normally found in mine ventilation air, so this practice increases the body of field experience MEGTEC can claim in processing dilute methane flows. MEGTEC also suggests that a ventilation air project operator could inject gob gas into a TFRR to enhance the methane concentration.

3.1.3 Catalytic Flow-Reversal Reactor

The U of U analysts ran a simulation of the catalytic flow-reversal reactor under conditions identical to the TFRR trials and found it to be technically feasible as well. The simulated process modeling clearly showed that during steady-state operation the CFRR remains stable and autothermic at low methane concentrations. It blows out only when concentrations reach just above 0.1 percent. CFRR cycle duration appears to be longer than TFRR cycles, but this difference will not have a material effect on system performance.

The assessment did not take into account the potential for conditions that could adversely affect catalyst performance (e.g., temperature cycling or catalyst poisoning from sources such as dust). These concerns can be studied during field trials. If such problems occur they will result

[11] The supporting data were contained in a report entitled *Submission of Additional Information from MEGTEC Systems – Applicability of the VOCSIDIZER*, July 1999.

in increased operation costs because of more frequent catalyst replacement and unscheduled down time.

3.1.4 Pressure Drop

In addition to the numerical modeling, the U of U research team performed an analysis of pressure drops created by the volume of ventilation air passing through the systems. The U of U analysts calculated pressure drops for a range of flow rates, reactor diameters, and voidage fractions. Since they used an "effective diameter", the results are valid for any internal configuration. Calculated pressure drop results were not excessive. That finding, shown in Table 2, indicates that manufacturers should be able to install reactors of a reasonable size and still maintain required air velocities using affordable fan systems. For example, with a voidage fraction of 0.5, a flow rate of 21,200 cfm (10 m^3/s), and a diameter of 19.69 ft (6 m), the pressure drop is less than 15.75 inches (400 mm) of water. The calculations also confirm pressure drop data reported by CANMET.

Table 2. Pressure Drops for CFRR and TFRR Processes Using Various Flow Rates, Diameters, and Voidages

Flow Rate Cfm/(m^3/s)	Diameter* ft/(m)	Velocity ft/s/(m/s)	Voidage Fraction	Pressure drop (in/mm water)
2,120/1	3.61/1.1	3.12/0.95	0.5	45.79/1163
2,120/1	3.61/1.1	3.12/0.95	0.7	8.90/226
2,120/1	6.56/2.0	1.05/0.32	0.5	13.86/352
2,120/1	6.56/2.0	1.05/0.32	0.7	2.68/68
21,200/10	11.48/3.5	3.41/1.04	0.5	45.20/1148
21,200/10	11.48/3.5	3.41/1.04	0.7	8.79/223
21,200/10	19.69/6.0	1.15/0.35	0.5	15.35/390
21,200/10	19.69/6.0	1.15/0.35	0.7	2.99/76

* Effective diameter. In practice, smaller multiple units may be used.
Source: University of Utah.

3.2 Technical Assessment Summary

Numerical modeling and gas flow calculations demonstrate that both flow-reversal oxidation processes are technically feasible. It is too soon to render definitive opinions on comparative performance because neither the CFRR nor the TFRR has operated on mine ventilation air at commercial scale, under actual field conditions, with full documentation. As discussed in Section 5, while there is little apparent difference in terms of unit capital and operating costs, there are a few factors that may tend to affect the selection of one process or the other.

3.2.1 Catalytic Flow-Reversal Reactor

- CANMET asserts that catalytic oxidation allows the use of smaller units because with lower temperatures the wave front moves more slowly, thus traveling a shorter distance between flow reversals. Both the lower temperatures and smaller size tend to favor a lower capital cost. The catalytic process, however, must bear the added cost elements of purchasing, maintaining, and replacing the catalyst.

- Because the CFRR has been developed specifically for the treatment of mine ventilation air, it may perform more efficiently and cost-effectively than the TFRR. Field trials will prove or disprove this supposition.

- While U of U computer simulations indicate the CFRR is able to operate at lower concentrations, MEGTEC's field data confirm that the TFRR can match that performance. This factor is important in estimating how much energy effectively can be recovered from the reactor (see detailed discussion in Section 4).

3.2.2 Thermal Flow-Reversal Reactor

- With over 600 TFRR units operating in the field, MEGTEC would seem to have an advantage in terms of "proof of concept" as compared with CFRR's laboratory trials and modeling. Many of these units must operate intermittently on methane of similar concentration levels as ventilation air methane during periods when normal feedstock is in short supply.

- The TFRR has no operating costs associated with a catalyst.

4.0 PRACTICAL METHODS FOR USING ENERGY RECOVERED FROM VENTILATION AIR OXIDIZERS

While the emphasis of this report is on the ability of various technologies to combust methane in ventilation air, it is important to explore the practical systems that will recover and use the energy thus created, enabling developers to install and operate such systems profitably. This section examines some of the technical issues of energy recovery and introduces some methods that may be practical and cost-effective.

4.1 Heat Available for Recovery

When methane borne by the ventilation air combusts, it releases heat, but not all of that heat is available for recovery. Some of the heat is required to sustain reactor temperatures, and if methane concentrations are in the lowest sustainable range, most or all of the heat of combustion goes for that purpose. Figure 6 depicts the relationship of recoverable energy as a function of methane concentration. The higher the available concentrations are (i.e., the area where the curve begins to level off) the greater will be the percent of heat that may be recovered by the heat exchanger. Figure 6 covers a broad area having its origin at a range of points on the X-axis between 0.1 and 0.3 percent methane, representing the minimum methane concentration of ventilation air at which the reactor is autothermic. The two reactors reviewed in Section 3 are autothermic at temperatures consistent with this range.

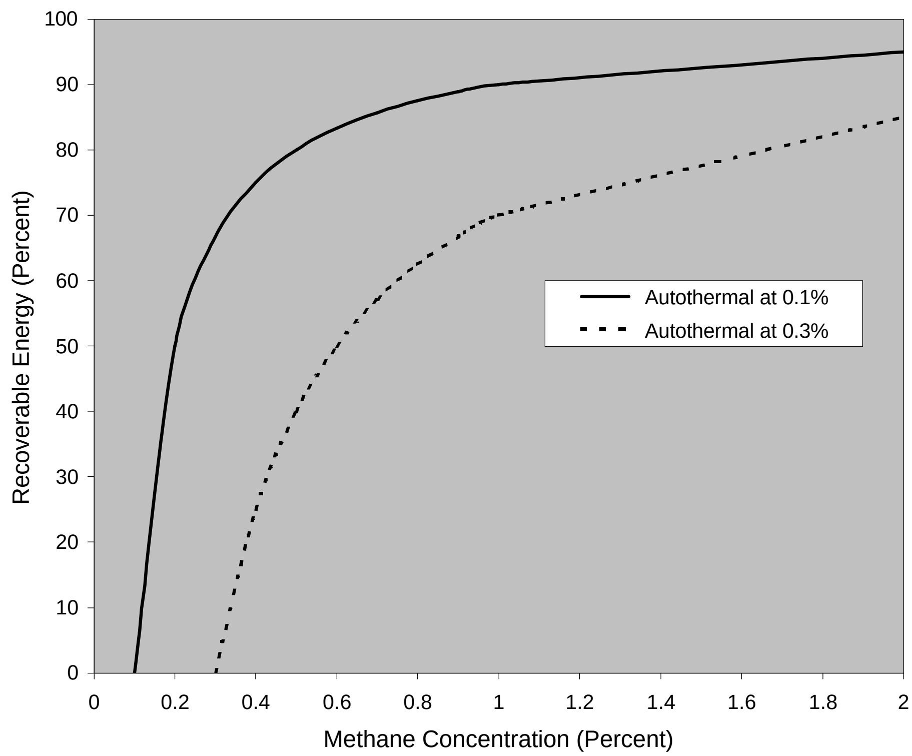

Figure 6. Percent of Energy Recovered as a Function of Methane Concentration in Ventilation Air

Source: Calculation by U of U.

Upon examination of the curve one can see that a small increase in methane content may result in a dramatic increase in the amount of energy available for recovery and use, especially in the steeper parts of the curve. Injection of methane at this point not only creates more heat, but it causes a larger fraction of that heat to be recovered. Therefore, developers may wish to consider the possible economic advantages of injecting gob gas into the ventilation air stream to exploit this phenomenon.

MEGTEC has reviewed the practicalities of injecting methane in the form of gob gas into the ventilation air as a support fuel. In fact, the use of natural gas as support fuel in general industrial process air streams (containing trace organic compounds other than methane) is one of the prime design features that enhances the effective operation of TFRR units in the field, according to the company. In general industrial settings the TFRR injects make-up fuel just upstream of the poppet valves that admit ventilation air into the unit. Good mixing results from having a well-located and well-configured gas injection port and a significant pressure drop across the bed and poppets. The company is confident that they can achieve the same result with supplemental methane injection into the ventilation air application.[12]

CANMET has also looked at this issue, and they agree that methane injection may be a cost-effective method of maximizing energy yield from the system.[13] The use of gob gas to enhance heat recovery from the reactor may have to compete with using gob gas as a supplemental fuel in the prime mover. Section 4.4 below addresses the question of which use is more cost-effective.

4.2 Technical Issues Concerning Heat Exchangers

The following issues will influence the design of a system recovering useful energy from either a TFRR or a CFRR installation.

4.2.1 Embedded High-Temperature Heat Exchangers

Of the three heat extraction methods described in Section 2, the embedded high-temperature heat exchanger offers the highest quality heat in the most practical form. The other two methods are not practical for most applications: using exhausted, oxidized ventilation air does not provide a high-temperature medium, and extracting high-temperature ventilation air is complex and may upset the reactor's operation.

Whichever technology requires less energy to maintain operation of the reactor itself will be able to recover more of the input methane as useful energy. A TFRR theoretically could be designed to produce higher temperatures than a CFRR, and thus a higher quality and more useful form of heat for producing electricity. Such an ideal advantage would come at a high cost if compressed air were the selected heat transfer medium, as discussed below, because higher temperatures require the heat exchanger and transfer piping to be made of expensive materials that can withstand high-temperature stresses. MEGTEC will probably opt for water as its heat transfer medium.[14]

[12] Martin Key, European Manager, Marketing and Business Strategy and MEGTEC Systems AB, Submission from MEGTC Systems, *Applicability of VOCSIDIZER*, February 28,1999.
[13] Telephone communication with Dr. Hristo Sapoundjiev, Research Scientist, February 22, 1999.
[14] See footnote 12.

As shown in the following paragraphs, embedded heat exchangers introduce a number of design questions that must be solved for each project application.

4.2.2 Handling High Temperatures

Both the thermal and catalytic reactors (but especially the TFRR) reach temperatures that exceed the working limits of all but the more durable materials such as high-grade stainless steel, Inconel, and ceramics. For purposes of comparison, an oxidizer (even the CFRR) can produce working fluid temperatures in the heat exchanger (circa 1382 ^{o}F or 750 ^{o}C) that exceed, by more than 50 ^{o}C, the maximum allowed metal temperatures of the specialized superheater tubes in a modern steam power station. Thus, if the circulating medium in a high-temperature heat exchanger's secondary (i.e., receiving) circuit is compressed air, the air provides little mass to absorb the thermal shock to the embedded tubes, and the tubes will have a short useful life unless constructed with proper materials. In many cases, the price to be paid for materials that withstand high temperatures can be a good investment that will be repaid with increased revenues from gas turbines that produce electricity more efficiently with a higher-temperature working fluid. If the circulating medium is pressurized water, fewer special design precautions are needed.

4.2.3 Placement

The designer has the flexibility to locate the heat exchanger piping (i.e., tubes, coils, etc.) at the bed's center where the reactor maintains its highest temperature, or at cooler points along the temperature gradient. Therefore the designer has more choices when trading off high efficiency and performance with the high cost of exotic metallurgy. Heat exchanger placement may have an effect on the operation of the reactor, but research performed for this report did not analyze any possible consequences. Also, if heat exchange tubes are embedded in cooler regions of the reactor, the working fluid's temperature may fluctuate significantly during every half-cycle as the heat wave in the reactor approaches and retreats. The designer would have to find ways to prevent such fluctuations from affecting the energy recovery function, for example by blending the two flows to achieve an average and steady working fluid temperature.

4.2.4 Maintenance

Heat exchanger elements will require a higher level of monitoring and maintenance than most of the remaining parts of the oxidizer. The reactor design should facilitate easy removal and replacement of the more vulnerable components.

4.3 Energy Conversion Options

After the heat exchanger delivers energy in the form of pressurized hot water or compressed hot air, the developer has several options to produce useable energy. This section briefly discusses the more practical of these.

4.3.1 Direct Use of Thermal Energy

This is the simplest and least capital-intensive option. Its economic viability depends upon the existence of a nearby market for thermal energy such as:

- District heating
- Industrial process heating

- Coal drying
- Mine wastewater desalination
- Heating ventilation air inflows during winter months

The configuration and cost of such systems will vary greatly according to the specific use. For example, a heat exchanger within either a TFRR or CFRR can be either air-cooled or water-cooled. Heated and pressurized air exiting the heat exchanger can flow directly into a waste heat boiler (or heat recovery boiler) to produce either steam or hot water. If the working fluid is pressurized hot water it would flow to a pressurized flash tank where it converts to steam as described in Section 4.3.2 below.

Section 5 reviews the cost and profitability of an illustrative project using pressurized hot air to raise steam in a waste heat boiler serving a very simple district heating system located near the mine. This example will have application in some areas of eastern Europe where district heating systems located near active ventilation shafts are relatively common.

4.3.2 Electric Generation Using Steam Cycle

The heat exchanger within either of the two oxidizers can be effectively cooled with pressurized water. Heat exchanger outlet temperatures up to about 572^o F (300^o C) are suitable for use in heat recovery steam boilers that are either unfired or supplementary-fired to raise steam in a waste heat boiler setting. The probable project configuration would be to feed the hot water to an external flash chamber from which steam is captured for steam power cycle use. If sufficient gob gas is available, a conventional waste heat boiler including a superheat stage could be used in a supplementary-fired mode to raise the efficiency of the system.

In this case, water circulates under high pressure through the heat exchanger but is not allowed to boil. The heated water then crosses a control valve into a pressurized tank resembling a boiler steam drum. The tank maintains a pressure level where a portion of the water will "flash" into steam, lowering the temperature of the water to correspond to the saturation temperature of the steam. The steam passes into a power turbine, which converts some of its energy into shaft power (which in turn drives an electric generator). Condensate from the power turbine’s cooling system serves to replenish water in the heat exchanger recirculation loop. It also acts as a coolant for avoiding cavitation (the formation of cavities caused by low-pressure bubbles) and suction loss in the recirculation pump.

In a project requiring electric generation only, the designer would choose a condensing steam turbine with an evaporative cooling tower, either wet or dry depending upon the availability of cooling water at the site. If a revenue-producing thermal load is available periodically or continuously at a relatively constant demand, the turbine choice would be between an extraction/condensing steam turbine or a back-pressure steam turbine.

Unfired Boiler.

In the case of the unfired boiler with a condensing turbine, the overall efficiency will be limited to between 15 percent (22,750 Btu/kWh or 24,000 GJ/kWh) and 20 percent (17,065 Btu/kWh or 18,000 GJ/kWh) because of pressure limitations and the lack of superheat. The water temperature at the heat exchanger outlet should be at least 550 ^{o}F (288 ^{o}C) under a pumping pressure of at least 75 atmospheres (1,100 psig) to allow sufficient pressure range for flashing while still resulting in a reasonably efficient steam cycle at a somewhat lower steam temperature and pressure caused by the flashing.

Fired Boiler.

In the case where gob gas or other affordable fuels are available to superheat the steam, the cycle efficiency could reach as high as 25 percent (13,650 Btu/kWh or 14,400 GJ/kWh) if gob gas is available in the proportion of at least 25 percent to the methane in the ventilation air. In this case, the steam boiler could be operated at 85 to100 atmospheres (1,250 to1,500 psig) and with a superheat temperature of up to 950 ^{o}F (510 ^{o}C). Such design parameters depend on cost-benefit analyses, which compare increased superheater costs with increased revenues from additional electricity sold.

Both steam cycle cases (fired and unfired) will probably require higher capital costs and produce lower cycle efficiencies when compared with a gas turbine case discussed below. MEGTEC has indicated that it does not share that opinion, and instead prefers to use a large power generating system based on high temperature and pressure steam conditions.[15]

4.3.3 Electric Generation Using Gas Turbine

It is likely that the preferred electric power production option will be the use of a gas turbine operating in a cogeneration mode by recovering waste heat. Typical efficiencies for converting thermal energy to electrical power are about 28 to 35 percent when operating under design conditions.

A description of the gas turbine option begins at the upper left corner of Figure 7. Ambient air, or possibly ventilation air, enters the compressor mounted on the air turbine's shaft and is compressed to between 7 and 22 atmospheres (or about 100 to 325 psig) depending upon the turbine design. Compressed air flows through the secondary loop of the gas-to-gas heat exchanger in the reactor where it receives excess heat of combustion. It then returns to the turbine's expansion section where part of its energy converts to mechanical energy and then into electrical energy in the generator. Spent hot air then enters a waste heat boiler, which captures useful thermal energy, if cogeneration is desired.

Design Trade-Offs.

Gas turbine efficiency improves as a function of the temperature of its working fluid, but high temperatures require high-cost exotic metals in the heat exchanger. Moreover, the efficiency of the gas-to-gas heat exchanger in the reactor tends to decrease with high temperatures. The design of a heat recovery system to be linked to a gas turbine requires a trade-off between turbine efficiency and cost, and heat exchanger efficiency and cost.

Benefits of high temperatures:

- Reduced air flow in secondary circuit
- Smaller gas turbine
- Higher gas turbine efficiency
- Less supplemental fuel

[15] See footnote 11 above.

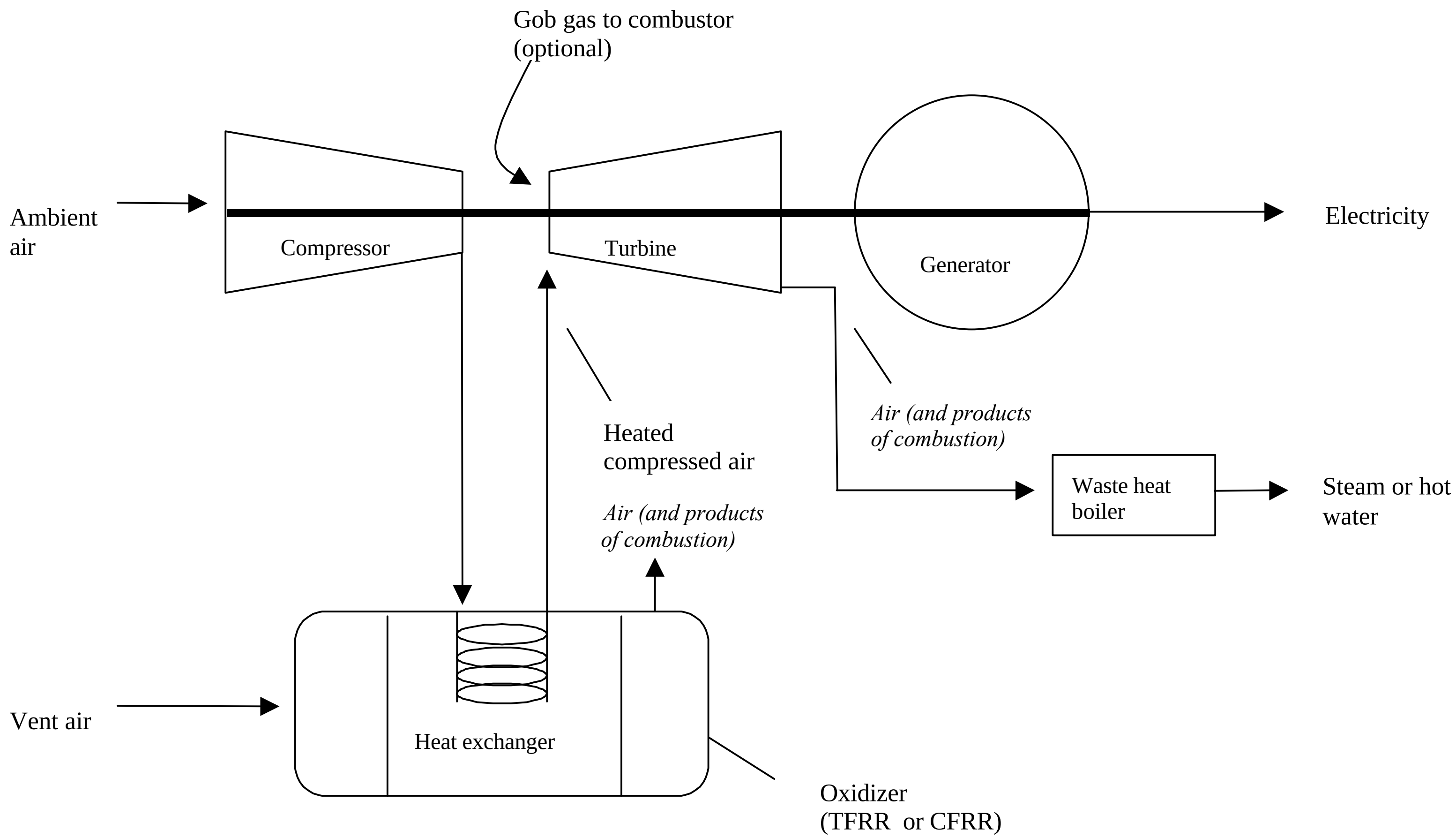

Figure 7. Schematic of Cogeneration Option

Penalties of high temperatures:

- Higher heat exchanger cost
- Lower heat recovery

Turbine Matching.

Modern high-efficiency gas turbine specifications call for higher turbine inlet temperatures than are economically available from a ventilation air oxidizer. The highest practical temperature range for the reactor outlet may be between 1382 ^{o}F and 1472 ^{o}F (750 ^{o}C and 800 ^{o}C), and that is at or below the input needs of older and smaller gas turbines. The maximum working temperatures for large (>25 MW) modern turbines are over 2192 ^{o}F (1200 ^{o}C), and even at smaller sizes of <20 MW, advanced gas turbines starting to come on the market will be able to operate at levels as high as 2102 ^{o}F (1150 ^{o}C) while achieving efficiencies well over 35 percent. The system designer will carefully match the temperature and mass flow characteristics available at a given mine with an off-the-shelf gas turbine. For any given gas turbine, one can construct a performance table, or a capacity curve can be constructed with input from the manufacturer based on the mass-flow and temperature of the hot air entering the power turbine. The designer will also want to find a turbine with a high compressor efficiency along with other desirable characteristics.

Currently there are about two dozen turbine models on the market in the 1.5 to 20 MW size range. Appendix C offers a sample list of commercial gas turbines, illustrating the variety of units available. This diversity will give a designer reasonable flexibility to match a readily available commercial unit or a used older model with expected mass flows and temperatures at the heat exchanger outlet.

Supplementary Firing.

The design effort will be aided greatly if the mine can supply sufficient gob gas or another affordable fuel for supplementary combustion in the turbine to raise the working fluid temperature to design levels, or nearly so. In some cases, the supplementary firing needs will compete with the need to supplement vent air methane concentrations (see Section 4.4 below). If ample supplemental fuel is available it could be possible to adjust the mass flow and firing temperatures to correspond exactly to a given gas turbine's design specifications, allowing it to operate at optimum efficiency. Moreover, supplemental fuel may afford an opportunity to decrease the heat exchanger outlet temperature to some lower value that will allow less expensive construction materials. If gob gas is insufficient to allow the gas turbine to achieve its design temperatures, the project may either purchase natural gas or oil for that purpose, or may operate at a derated output and a reduced efficiency.

Refinements to Efficiency.

If there is little or no demand for cogenerated steam, there may be cost-effective methods to improve electricity production by using heat exhausted from the gas turbine. One option is to insert an interstage heating unit at the turbine exhaust to use waste heat to raise the temperature of pressurized air going to the reactor's heat exchanger. This would decrease the working fluid's temperature gain in the heat exchanger and allow for an increased flow, a larger turbine, and extra revenue. Such considerations should wait, however, until the basic process has proven itself in field trials.

4.4 Allocation of Scarce Gob Gas: Flow-Reversal Reactor Versus Gas Turbine

This section outlines a procedure for optimizing the allocation of scarce supplemental fuel, usually gob gas, to the two system components that can benefit from the additional energy (i.e., the reactor and the gas turbine).

At most gassy mines, ventilation air is the major source of CMM emissions, with the remainder being pipeline-quality methane and/or gob gas. A project designer will normally find that the mine's supply of gob gas is inadequate for both (1) enabling the gas turbine to operate at its design turbine rotor inlet temperature (TRIT), and (2) enhancing the percentage of heat recovered from the reactor as determined by Figure 6. Before starting an analysis to allocate supplemental fuel and/or gob gas supply to its most effective use, the analyst must determine whether or not some amount of "support fuel" is necessary just to assure that ventilation air methane concentrations are far enough above autothermic levels to permit some heat recovery without threatening reactor stability. If process stability turns out not to be an issue, the next task is to perform an optimization study that varies gob gas allocation to maximize power output. The first step in that process is to determine how the turbine responds to a TRIT that is below design level.

4.4.1 <u>Determine Efficiency Impact from Decreasing Turbine Inlet Temperature</u>

Using data from the turbine manufacturer, prepare a table or a curve for the unfired and partially fired gas turbine cases that estimates reduced efficiency levels when TRIT falls below design levels. Such a curve for a typical off-the-shelf, industrial frame turbine might appear as follows:

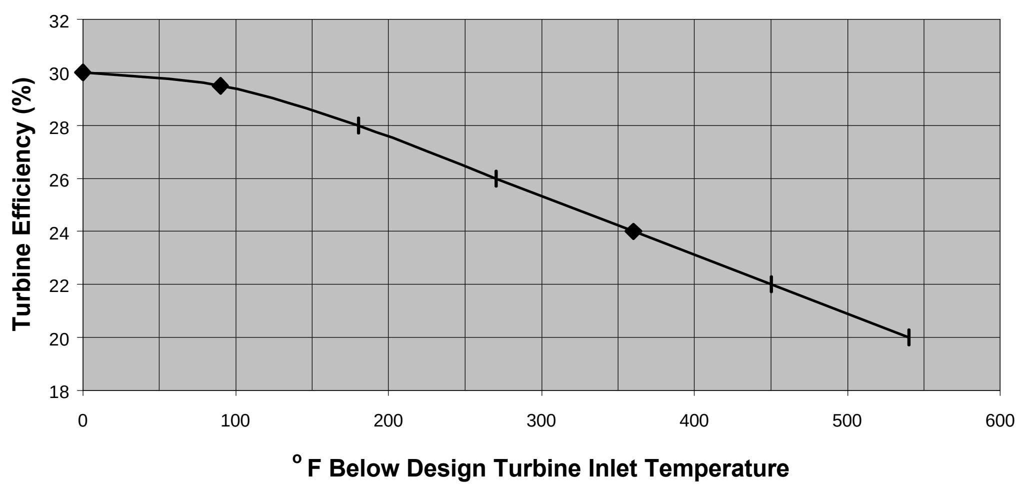

Figure 8. Turbine Efficiency versus ^{o}F below Design Turbine Inlet Temperature – Generic Case

Note that turbine efficiency begins to fall off dramatically when TRIT is near 90 ^{o}F (50 ^{o}C) below design specifications. In the illustrative Figure 8, turbine efficiency would be about 20 percent at 540 ^{o}F below an assumed design TRIT of 1840 ^{o}F (or at 1300 ^{o}F), which is the assumed outlet temperature of the reactor's heat exchanger. Thus, in this case the unfired turbine (with no gob gas allocated to its combustor) would be 20 percent efficient.

4.4.2 ***Optimize Use of Scarce Gob Gas***

This step involves constructing a spread-sheet model with a range of cases, each representing an increment of gob gas directed to the reactor (which corresponds to a decrement of gob gas taken away from the turbine). Each incremental case will represent an increase in the methane concentration entering the reactor, resulting in an increase in available energy. Using the reactor manufacturer's recovery curves (similar to Figure 6), the analyst can estimate a heat recovery percentage and calculate the total energy added to the compressed air working fluid. The next steps for each case develop the mass flow of the working fluid from the reactor (air from the turbine compressor), total heat delivered to the turbine including heat from the gob gas as well as heat recovered from the reactor, working fluid changes due to combusting gob gas, the TRIT with a corresponding turbine efficiency derived from the turbine efficiency curve similar to Figure 8, and the turbine-generator's electrical output. Finally, the analyst will plot the results.

See Appendix D for a typical example of a spread-sheet model for allocating gob gas. In this example 20% of the gob gas is being supplied to the reactor and 80% to the turbine.

4.4.3 ***Illustrative Example***

The following is an illustration of the optimization procedure described above. The case uses some of the same CMM assumptions used in Section 5:

- Ventilation airflow, 212,000 cfm (100 m^3/s)
- Methane concentration, 0.5 percent by volume
- Gob gas (methane), 868 cfm (0.41 m^3/s)

Figure 9 shows the effect on power output of varying allocations of gob gas to the reactor and the turbine combustor. The three curves represent three concentrations of methane in ventilation air: 0.4, 0.5, and 0.6 percent by volume.

This example shows that most of the gob gas should go to the turbine to achieve the highest energy value for a given supply of CMM, especially when ventilation air methane concentrations are high. At 0.4 percent methane, about a quarter of the gob gas should be directed to the reactor, and three quarters would most productively go to the turbine combustor. If all the gob gas were to be consumed in the reactor, the plant would produce about 18 percent less than optimum in all three curves.

4.4.4 ***Practical Implications***

The optimization exercise described above gives developers a guideline to keep in mind during the complex design of a ventilation air methane recovery plant. The exercise took place without considering potential impacts on capital budgets or project durations of the availability and quality of any of the CMM sources. Clearly, such case-specific parameters will influence the conclusions indicated above.

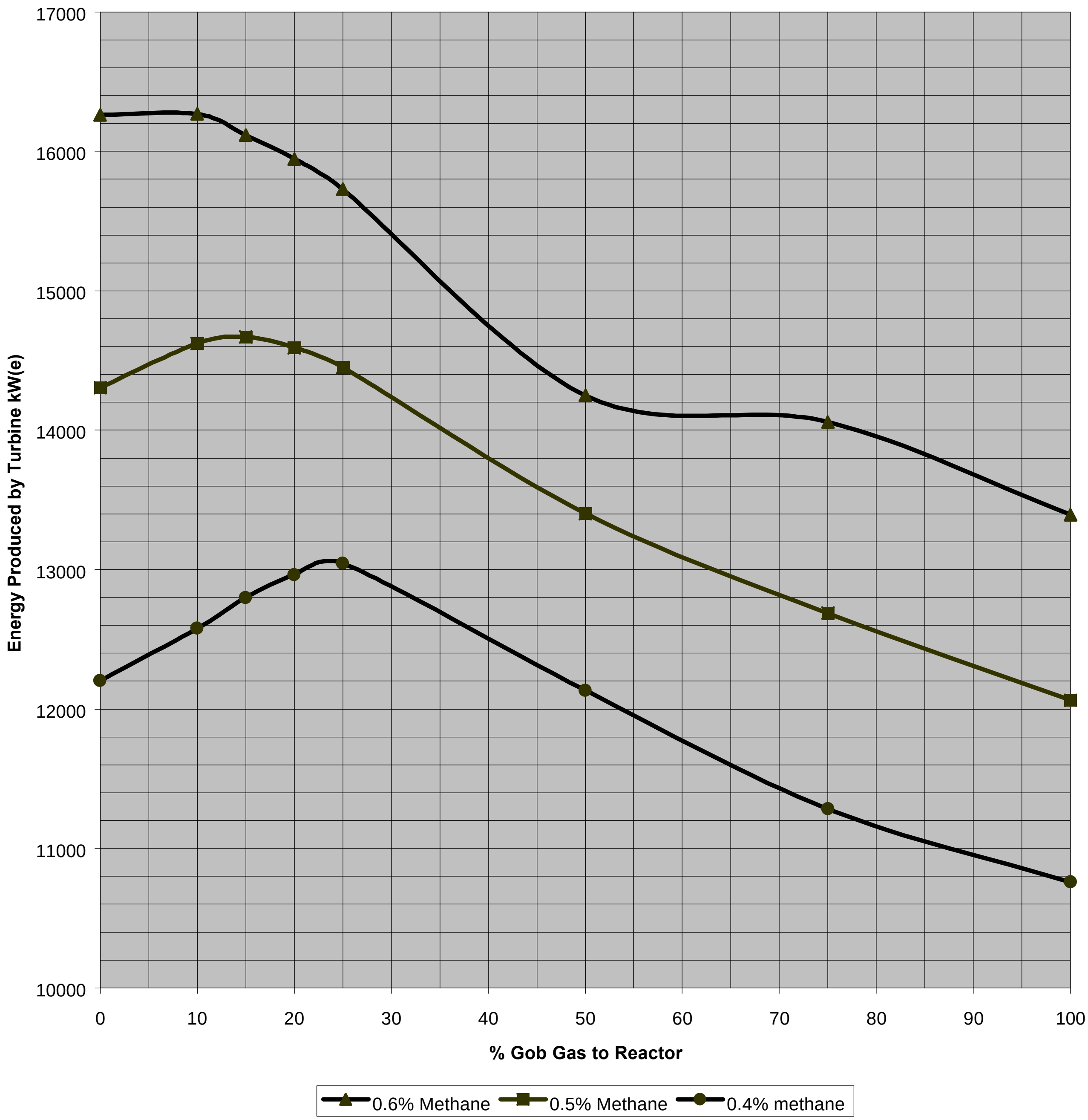

Figure 9. Turbine Power Output at Various Gob Gas Allocations between the Flow-Reversal Reactor and the Gas Turbine – Generic Case

5.0 ACTUAL AND HYPOTHETICAL PROJECT CONFIGURATIONS

This section illustrates the applicability of identified ventilation air processing techniques at actual or hypothetical gassy mines. Section 1 discussed the ideal criteria for such projects, which are:

- Ability to accept entire flow from a single ventilation shaft;
- Exothermic, sustainable, and reliable chemical reactions;
- Simple, rugged design consistent with sound engineering;
- Technology demonstrated at large scale; and
- Profitable after byproduct recovery.

Although no current project meets all five criteria, one project meets four of five and there is a reasonable possibility that demonstration projects in the next few years will meet all five. The following subsections describe one actual and three hypothetical projects that illustrate the economic potential for ventilation air mitigation.

5.1 Ancillary Use of Ventilation Air

The following cases that use ventilation air methane as an ancillary fuel exemplify both a partial use (Appin project in Australia) and a total use (a hypothetical case featuring a mine-mouth coal-fired power plant).

5.1.1 Partial Use of Ventilation Air in Internal Combustion Engines

The BHP project in Australia introduced in Section 2 is the only large-scale user of ventilation air methane in the world. Proving that internal combustion engines can substitute ventilation air for ambient air in its combustion air intake system, the project fully demonstrates the feasibility of beneficial partial use of methane emitted from a ventilation shaft.

In 1995 BHP Collieries Division and its partners, Energy Development Limited (EDL) and Lend Lease Development Capital (LLDC), installed two power generating projects near two underground coal mines in New South Wales, Australia, about 80 kilometers south of Sydney. Each facility consists of a series of Caterpillar 3516 spark-fired, 1500 rpm engines, each of which directly drives a one-megawatt generator. Each engine/generator unit is housed within its own acoustic enclosure. There are 40 units at the Tower Colliery and 54 units about seven kilometers away at Appin Colliery, for a total generating capacity of 94 MW. Methane (both in-seam and gob gas) drained from the mines, with methane content fluctuating between 40 and 60 percent or more, is the primary fuel for the project. An underground pipeline facilitates the transfer of CMM and natural gas between the two projects.

Mine ventilation supplies combustion air for the 54 Appin engines. The ventilation air averaged about 0.7 percent methane until recently when it diminished to about 0.3 percent. An air filtration system removes particles from the air before it travels to the engines. Fuel value contributed by this air stream could peak up to 10 percent of each engine’s fuel needs, amounting to 5.4 MW when all engines are running, although recently this contribution has declined. The Appin power project consumes up to 20 percent of the mine’s vented methane emissions when operating at capacity.

In the project's power sales agreement, BHP and its partners contracted to operate at full capacity during peak periods. To accomplish this, the project must rely on natural gas to supplement its primary fuel during periods of low gob gas flow. During off-peak periods the project is allowed to sell all of the electricity it can produce, but, because it receives a lower price per kilowatt hour, it relies upon only low-cost fuels (i.e., gob gas and ventilation air).

BHP reports that total capital costs (excluding the pipeline tying the projects together, and an office building) were about US$70 million or about US$750 per kW installed. The company does not supply detailed data on operating costs, revenues, and profits, but they express satisfaction that the projects are achieving their financial goals.

While BHP has not identified separate capital and operating expenditures for the air substitution part of the project, a Caterpillar spokesman stated that these were modest. They consisted of ducting installed from just above the ventilation fan to each engine's air intake, the air filtration system, and some additional programming at the control centers. There are no additional fans in the ductwork because the engines generate enough suction power to move ventilation air to their intake systems.

One can conclude that the ventilation air substitution system is a simple and practical technique for CMM use that could be replicated at many gassy mine settings where electricity generation using gob gas may be viable. In the Appin setting, this innovation probably yields a positive cash flow because, for very little additional cost, the project realizes economic benefits. These are roughly estimated as follows:

- The system's methane contribution allows the power plant to reduce natural gas purchases to meet peak demand. For example, the plant might be able to save ten percent of the natural gas purchased for half the plant (i.e., 27 MW). If natural gas costs about US$20 per MWh, and there are 3600 peak hours in a year, the use of ventilation air methane could amount to approximately US$200,000 per year in natural gas cost.

- The methane in ventilation air allows the power plant to produce incremental electricity revenue during off-peak hours. For example, if the plant could produce ten percent extra power during off-peak periods at an electricity rate of US$20 per MWh, that would yield US$54 per hour times an assumed 4,400 hours per year, for an annual increase of about US$240,000.

- If the additional capital cost for installing the ventilation air transport and processing system was in the range of US$500,000, the payback would be slightly over one year.

5.1.2 Total Use of Ventilation Air in a Mine-Mouth Coal-Fired Plant

A coal-fired power boiler is a good example of a class of large energy consumers that have combustion air demands roughly matching the air output of a typical mine ventilation shaft. For example, a shaft emitting 2 mmcfd (0.656 m^3/s) of methane at a concentration of 0.5 percent has an airflow of about 400 mmcfd (131 m^3/s). That is enough air to replace ambient air for a mine-mouth coal-fired power plant rated at approximately 125 MW. This strategy is technically feasible and would be economical if the plant already exists or will soon be built near a mine ventilation shaft. As mentioned in Section 1, Powercoal of Australia is considering such a project at an existing adjacent coal-fired power plant.

For a developer to place a new coal-fired plant near a mine to compete in the current U.S. power market, however, this option will require some careful analysis. There are at least three levels of concern:

1. New coal plants are increasingly less able to compete in the domestic power generation business, regardless of location. Most new capacity will utilize natural gas-fired turbines operating in combined cycle. Moreover, coal units in the 125 MW range illustrated herein are less cost-effective than larger modules.

2. It may be risky for a power developer to count on these supplemental fuel sources (ventilation air and gob gas) for the economic life of the plant, typically 40 years. There is a strong possibility that the CMM sources may decline or cease flowing altogether because mining operations may have moved far from the power plant or discontinued entirely.

3. The benefits of the mine-mouth option include: inexpensive and free fuel, no coal freight (because it consumes coal mined on site), and NO_x and carbon offsets. Can these benefits reward the power producer for locating the plant away from more central sites when transmission lines, cooling water, and construction labor pools are plentiful? The following analysis attempts to address that question.

Economic Analysis

Responses to the first two concerns will depend upon case-specific circumstances and cannot be fully addressed herein. To examine the third concern, U.S. EPA prepared a simple analytical tool on an Excel spreadsheet. Appendix E-1 presents this model, and the results are discussed below.

The model compared a “traditionally sited” 125 MW coal-fired power plant with an identical plant located a very short distance from a gassy mine. The model assumed the following significant differences for the mine-mouth location in terms of construction details:

- Extra transmission line, varying from 10 to 40 miles (16.1 to 64.4 km) long.

- Extra construction labor costs of 15 percent (accounts for travel, worker’s camp expense for remote locations, premium time, etc.).

- Dry cooling tower, which adds a small additional capital cost and a parasitic power loss.

Assumed advantages accruing to the mine-mouth plant are:

- Free fuel contribution from the ventilation air, fixed at (2 mmcfd)0.656 m^3/s.

- Inexpensive gob gas (e.g., $0.60/mmBtu, varying from (1 to 3 mmcfd) 0.328 to 0.983 m^3/s).

- Reduced NO_x resulting from introduction of two methane sources. Credit value varies from zero to $3,500 per (short) ton of NOx.

- Carbon credits resulting from substituting two forms of CMM, valued from zero to $2.00 per metric tonne of CO_2. Methane is equivalent to 21 times the weight of CO_2 and 5.73 times the weight of carbon. [16]

The purpose of the model is to obtain a rough approximation of a cost/benefit relationship. The model uses a simplified discounted cash flow format to estimate the internal rate of return (IRR) for the additional capital invested in the mine-mouth plant, such as the transmission line and the increased construction labor cost. Assumed financial parameters include a ten-year project life and all equity financing. This simple model does not calculate depreciation or account for income tax. The model also ignores the small impact of cooling tower derating from year 11 and beyond. If a potential project were to pass this screening step. A much more rigorous analysis would be appropriate.

Preliminary Base Case Results

The following parameters were used to calculate the Base Case IRR:

Electric transmission line length:	30 miles (48.3km)
Cooling tower derate:	2 percent
Gob gas available:	2 mmcfd
Value of NO_x credit:	$2,500 per ton of NO_x
Value of CO_2 credit:	$1.50 per Mt of CO_2
Base Case IRR:	30.3 percent

Appendix E -1 contains a printout of the model and includes some sensitivity analyses that show how the IRR will change as the five parameters listed above change independently. Table 3 presents those sensitivity results which show that the NOx credit may be the dominant parameter if prices remain in the indicated range.[17] When all of the five parameters are at the most optimistic end of their range (i.e., the “Best Case”), the resulting IRR is 78.3 percent. The results clearly demonstrate that the project is heavily dependent on financial incentives arising from environmental benefits.

[16] Appendix F provides background on greenhouse gas emissions trading as well as a sampling of several known trades.

[17] Forecasting the future price of NO_x offsets is complicated by a recent U.S. Court of Appeals ruling which struck down U.S. EPA rulemaking for ozone compliance in 2003. Some market observers say that this action does not affect the 8-hour standard underlying NO_x trading. Others feel that the order will depress the market, and yet another group predicts that the market uncertainty favors offset purchases over investing in pollution control equipment. Source: Airtrends, Volume 2, Issue 17, May 1999 by Natsource.

Table 3. Results of Sensitivity Analysis

<u>Mine-Mouth Coal-Fired Plant</u>
(base case bold)

		IRR%			IRR%
Transmission Line	10	41.45	NO_x credit	0	9.60
(miles)	20	35.19	*($/ton)*	1000	20.55
	30	**30.29**		**2000**	**30.29**
	40	26.32		3500	43.87
Gob gas (*mmcfd)*	1.0	22.75	CO_2 credit		
	2.0	**30.29**	($/Mt)	0.00	25.14
	3.0	37.47		0.50	26.88
				1.00	28.59
Derate (*%*)	0	34.00		**1.50**	**30.29**
	2	**30.29**		2.00	31.97
			Best Case		78.29
			Worst Case		-1.48.

5.2 Principal Use of Ventilation Air

The two vendors of flow-reversal reactors, MEGTEC and CANMET, supplied U.S. EPA with some preliminary cost estimating information on a system rated at 212,000 cfm (100 m^3/s) of mine ventilation air. It is important to understand that cost data supplied for a general report such as this will be approximate and subject to change for the following reasons:

- Neither vendor has built and operated a full-scale unit appropriate for use at a gassy coal mine.
- Predicting the economics of energy recovery and marketing from reverse-flow oxidizers is difficult because the need to mitigate local pollution, rather than to compete in the field of energy supply, has driven the justification of all systems installed to date.
- System costs will vary greatly from one application to another due to the variation in physical and economic parameters at each site.
- Each vendor applied a different and unknown standard of conservatism to the estimates.
- Neither vendor is willing to reveal sensitive and confidential cost estimating information.

Nevertheless, there is cost information to build reasonable models that can suggest the economic viability of either the TFRR or the CFRR operating in the domestic U.S. marketplace. A review of the limited cost data showed that there is no clear difference between the two systems' costs, and it would be misleading to compare one against the other because of an incomplete understanding of the underlying case-specific design variables. Therefore, the following illustrative cases consider a "generic" design that blends the two systems and obscures any differences in performance, capital costs, and operating and maintenance costs.

U.S. EPA has supplemented the vendor-supplied information with reasonable and conservative estimates of project operating conditions, financial assumptions, revenues, and costs.
The following two hypothetical cases exemplify the use of either a TFRR or a CFRR using ventilation air as its primary fuel to generate electricity and/or thermal energy in a small power plant located at a gassy mine. The two cases are:

A. A flow-reversal oxidizer producing electric power and cogenerated steam with either a fired or unfired prime mover.

B. A flow-reversal oxidizer producing only steam.

5.2.1 Project A. Principal Use of Ventilation Air in a Flow-Reversal Oxidizer with a Gas Turbine Cogeneration Plant

This hypothetical project uses a single flow-reversal unit rated at 212,000 cfm (100 m^3/s) to capture most or all of the emissions from a nearby ventilation shaft at a gassy mine in the U.S. Project A relies on the methane captured from the ventilation shaft as its primary source of energy, and it relies on a limited supply of gob gas to enhance heat recovery in the oxidizer. An estimate of heat recovery enhancement is based on the slope of a section of the curve in Figure 6. As methane concentration increases due to gob gas injection, the total source of fuel increases as does the percent that can be recovered. In the “unfired case” all available gob gas goes into oxidizers, but in the “fired case” part of the gob gas finds a use in the gas turbine to raise the working fluid temperature and make better use of the turbine’s high-temperature capability. The fired case assumes that a substantial amount of methane in the form of gob gas is available to the project developer—a situation that may exist in several gassy mines in the U.S. The unfired case assumes a lower gob gas flow, and directs all of it into the reactor to enhance heat recovery.

A waste heat boiler placed at the gas turbine exit for both cases recovers thermal energy in the form of slightly superheated steam for local heat use.

This project will satisfy three of the five criteria listed above: can accept entire flow from a single ventilation shaft; has an exothermic, sustainable, and reliable chemical reaction; and has a simple rugged design consistent with sound engineering. As of the publication date of this report, the fourth criterion has not been met: there is no large-scale demonstration of the technology. In the TFRR case, however, several units in the field have operated on methane (natural gas) for discrete periods, and in the CFRR case there will be field trials as early as 2000 in Nova Scotia. The purpose of this case study is to apply a simple test of the fifth criterion. That is, using the preliminary cost estimates and reasonable assumptions, is Project A profitable after byproduct recovery?

Appendix E -2 contains a printout of a cash flow model for both the fired and unfired versions of Project A. The following paragraphs explain some of the assumptions underlying the model.

Engineering Considerations

This report selects a configuration for Project A based on the assumption that the hypothetical designers would have followed the concepts developed in Section 4 to specify components. The designers would perform a cost-benefit analysis to select the reactor outlet temperatures and heat exchanger materials. They would calculate airflow mass and select a reconditioned used gas turbine model requiring lower inlet temperatures in an attempt to optimize project economics. Because of the wide range of possible mine conditions, this report relies on representative parameters and turbine system configurations that are somewhere in the middle range of expected field situations for a gassy coal mine. Most of the selections are conservative.

Two factors that the analysis does not address are the decreasing economic lives of ventilation shafts and the development of new bleeder shafts. A CMM producer contacted for this report[18] commented that there are trends within the industry toward (1) employing small-diameter bleeder shafts in which methane concentrations may be one percent or more and airflows are lower and (2) moving ventilation fans every two or three years. These two related trends will tend to offset each other in terms of affecting profitability, as follows:

> Additional costs will arise because shorter vent shaft lives will require periodic costs for moving the energy recovery plant. Other costs would fall, however, due to decreased investment for smaller reactors and lower operating costs (e.g., reduced fan power needs). Project revenues will increase because higher methane concentrations produce more recoverable energy.

If these trends become widespread they may bolster ventilation air methane recovery and use projects by increasing revenue-to-plant investment ratios. Moreover, system designers can mitigate the costs and interruptions associated with frequent moves by designing plant components to be modular, portable, and easy to reassemble.

Both the unfired and fired cases use the following assumptions:

• Ventilation air flow	212,000 cfm, (305 mmcfd or 100 m^3/s)
• Methane concentration	0.5 percent
• Methane flow	1059 cfm (0.5 m^3/s)
• Percent heat recovered	Based on Figure 6; depends on gob gas input
• Heat exchanger outlet temp.	1,292^o F (700^o C)
• Heat exchanger air mass flow	88.16 lb/s (40 kg/s) + injected gob gas allowance
• Parasitic loss, fan, etc.	1,100 kW
• Operating hours/year	7,884 electric, 6,570 steam

Unfired case assumptions, base case:

• Gob gas available (as methane)	424 cfm (0.6 mmcfd or 0.2 m^3/s)
• Gob gas use	100% in reactor
• Calc. heat avail. for turbine	71.52 mmBtu/h (75.39 Gj/h)
• Turbine efficiency – unfired	22 percent
• Gross electrical output	4,610 $kW_{(e)}$
• Calculated boiler rating	11,434 $kW_{(t)}$

[18] From a memorandum from Joseph A. Zupanick, September 1999.

Fired case assumptions, base case:

- Gob gas available (as methane) 868 cfm (1.25 mmcfd or 0.41 m^3/s)
- Gob gas use 40% in reactor; 60% in turbine
- Calc. heat avail. for turbine 97.46 mmBtu/h (102.74 Gj/h)
- Turbine efficiency – fired 28 percent
- Gross electrical output 7,996 $kW_{(e)}$
- Calculated boiler rating 10,896 $kW_{(t)}$

Turbine capacity requirements are based on a dynamic calculation in the model. The analyst then rounds off to the nearest matching capacity of an off-the-shelf unit. An ideal selection would be a reconditioned older turbine designed for a lower firing temperature because it would achieve a better efficiency and an output closer to its nameplate rating. This is especially true for the unfired case.

Cost Assumptions

These cost estimates are based on information supplied by both vendors plus conservative estimates supplied by the contractor. Turbine-generator costs assume a reconditioned older unit and include a heat recovery boiler.

- Reactor cost +15% contingency, 212,000 cfm (100 m^3/s) unit, 0.5% methane $3.15 million
- Turbine-generator capital cost – per kW installed $650
- Project “soft costs” as percent of installed cost 25%
- Turbine-generator maintenance cost 0.0035/kWh
- Miscellaneous annual operating cost 3.2% capital
- Cost of gob gas per 1.055 GJ or mmBtu $0.60

Revenue Assumptions

- Electric sales price: Low: 3.0 cents/kWh High: 4.5 cents/kWh
- Thermal energy sales price: Typical price = $3.00/mmBtu, or about 1.0 cent/$kWh_{(t)}$

Carbon Offset Assumptions

- Vent and gob methane destroyed – unfired case 3,760 lb/h (1,706 kg/h)
- Vent and gob methane destroyed – fired case 4,908 lb/h (2,227 kg/h)
- Global warming potential: methane versus CO_2 21
- Assumed value of CO_2 per Mt $1.50

Results

Appendix E-2 contains the base case version for Project A, both unfired and fired. It also presents a limited number of sensitivity analyses that show how the IRR will change as five parameters change independently. Table 4 summarizes the base case and sensitivity results.

It appears that Project A will pass the profitability test, providing pricing conditions are favorable. For example, a power price of $0.035 combined with a greenhouse gas credit of $1.50 per Mt of CO_2 equivalent could allow the fired case to show a 29 percent IRR. It also appears that the fired case is reasonably resistant to selected parameter changes. If one of the following changes took place: only half the gob gas was available; if the electric price was only $0.03; if the methane concentration dropped to 0.4 percent; or if the carbon credit was only $1.00, the fired case would still be financially attractive. The unfired base case shows a 20 percent IRR, and it would be in, or close to, the profitability range if any one of the five parameters were to improve by one increment shown on the table.

Table 4: Results of Sensitivity Analysis

Project A: Flow-Reversal Oxidizer with a Gas Turbine Cogeneration Plant
(base case bold)

Capital cost		% IRR	% IRR
	%+or-	fired	unfired
	-20	44.6	33.3
	0	**29.3**	**20.2**
	+20	19.2	11.4
Electric price	*\$/kWh($_e$)*		
	0.03	23.8	16.7
	0.035	**29.3**	**20.2**
	0.045	40.2	26.9
Gob gas	*cfm (m^3/s)*		
	424/0.20	25.0	**20.2**
	635/0.30	27.3	22.9
	869/0.41	**29.3**	25.3
Methane concentration	%		
	0.4	24.6	14.9
	0.5	**29.3**	**20.2**
	0.6	33.3	24.2
Carbon credit	\$/Mt CO_2		
	0.00	18.0	9.4
	0.50	21.8	13.1
	1.00	25.6	16.7
	1.50	**29.3**	**20.2**
	2.00	33.0	23.6

5.2.2 *Project B. Principal Use of Ventilation Air in a Flow-Reversal Oxidizer in a Waste Heat Boiler Plant*

Hypothetical Project B uses a single flow-reversal unit rated at 212,000 cfm (100 m^3/s) to produce steam. Pressurized air from an electrically driven compressor goes through the heat exchanger in the reactor, gains heat, and releases it in a waste heat steam boiler. This option is useful when the mine is located near a stable thermal market such as a district heating system or a brine evaporation plant. Project B has a much simpler configuration than Project A, and its capital cost is substantially lower. As with Project A, the developer has two options if a substantial amount of gob gas is readily available:

- To improve the energy yield from the heat exchanger by increasing the methane concentration, or
- To increase the amount of steam produced by firing gob gas in the boiler.

This illustration assumes that methane in gob gas is available at the rate of about 50 percent of the methane flowing in the ventilation air. Appendix E-3 contains a printout of a cash flow model for Project B. The following paragraphs explain some of the assumptions underlying the model.

<u>Engineering Considerations</u>

It is a simpler task to allocate scarce gob gas for Project B because the heat exchanger yield will increase exponentially with supplemental fuel while the boiler yield would only increase linearly. The developer presumably will direct all supplemental methane into the reactor to enhance both the heat quantity and heat recovery percentage based on the curve in Figure 6. Therefore, the economic analysis for Project B only addresses the unfired case.

Project B uses the following assumptions for the base case:

• Ventilation air flow	212,000 cfm (305 mmcfd or 100 m^3/s)
• Methane concentration	0.5 percent
• Methane flow, ventilation	1059 cfm (0.5 m^3/s)
• Percent heat recovered	Based on Figure 6; depends on gob gas input
• Gob gas available (as methane)	0.76 mmcfd (527.8 cfm or 0.25 m^3/s)
• Gob gas use	100% in reactor
• Heat exchanger outlet temp.	1,112^o F (600^o C)
• Heat exchanger air mass flow	185.2 lb/s (84.0 kg/s)
• Parasitic loss, fan, etc.	900 kW
• Operating hours per year	7,884
• Calculated heat available for boiler	(80.54 mmBtu/h) 84.9 GJ/h
• Calculated boiler production	18,878 $kW_{(t)}$

<u>Cost Assumptions</u>

Some of the reactor cost estimates used in Project A are applicable for Project B. There may be a reactor cost reduction due to this project's assumed lower temperature in the heat exchanger, 1112^o F versus 1292^o F (600^o C versus 700^o C), but it is not reflected here.

• Reactor cost +15% contingency, 212,000 cfm (100 m^3/s) unit, 0.5% methane	\$3.15 million
• Boiler and ancillary equipment	\$0.944 million
• Project "soft costs" as percent of installed cost	25%
• Miscellaneous annual operating cost	3.2% capital
• Cost of gob gas per mmBtu or 1.055 GJ	\$0.60
• Power cost per kW/hr	\$0.05

Revenue Assumptions:

- Thermal energy sales price: Typical price \$3.00/mmBtu, or about 1.0 cent/kWh($_t$)

Carbon Offset Assumptions:

• Ventilation methane/hr	2698 lb (1224 kg)
• Gob methane/hr	1349 lb (612 kg)
• Global warming potential: methane versus CO_2	21
• CO_2 equivalent avoided per hour: 1.836 x 21	38.56 Mt
• Assumed value of CO_2 per Mt	\$1.50

Appendix E-3 contains a printout of the base case model for Project B. It shows an IRR of 33.3 percent, and it includes some sensitivity analyses that show how the IRR will change as four parameters change independently. Table 5 presents those sensitivity results.

Project B also has an excellent potential for profitability at a site where conditions are favorable. If the market for thermal energy could support a price of \$0.01 per kWh($_t$) and the project could earn carbon dioxide credits of \$1.50 per Mt, the project might show an IRR of about 33 percent. Even if the capital cost were to rise by 20 percent the project's IRR would come close to 25 percent. The IRR would remain above 25 percent if gob gas suffered a 25 percent shortfall or if ventilation air methane dropped to 0.44 percent. The project could only accept about a 14 percent drop in the thermal price before falling below 25 percent IRR, but that drop could be restored with a \$0.70 increase in the price of a metric tonne of carbon dioxide.

Table 5: Results of Sensitivity Analyses

Project B: Flow-Reversal Oxidizer with a Steam Plant
(base case bold)

Capital cost	%+or-	% IRR
	-20	47.9
	0	**33.3**
	+20	23.5
Steam price	$/kWh($_t$)	
	0.08	21.0
	0.1	**33.3**
	0.12	45.4
Gob gas	cfm (m^3/s)	
	265/0.125	20.5
	530/0.25	**33.3**
	794/0.375	46.0
Methane concentration	%	
	0.4	20.4
	0.5	**33.3**
	0.6	45.8
Carbon credit	$/Mt	
	0.00	14.3
	0.50	20.8
	1.00	27.1
	1.50	**33.3**
	2.00	39.5

6.0 CONCLUSIONS

CMM recovery and use is a function of its concentration and takes place in the reverse order of its occurrence in the field. In other words, the dominant form of CMM (i.e., that contained in ventilation air) has the least demand compared to gob gas and pipeline-quality CMM. Thus, the search for viable methods that use or at least destroy a major percentage of this source of greenhouse gas becomes extremely important to those who wish to mitigate methane emissions from coal mines effectively and economically.

6.1 Ancillary Uses

This report has made a distinction between technologies that use ventilation air as an ancillary fuel and those that use it as a primary fuel. Ancillary uses depend upon a nearby power facility or similar energy consumer that uses another fuel as its primary fuel. Except for the mine-mouth coal-fired plant, ancillary uses normally offer a partial destruction of ventilation air emissions. The leading ancillary use example is the Appin Colliery in Australia, which consumes up to 20 percent of the methane emitted from its ventilation shaft in 54 internal combustion engines. Appin's primary fuel is CMM (in-seam gas and gob gas) supplemented with natural gas, and its secondary fuel is ventilation air substituted at low cost for ambient combustion air. This project is very cost-effective, and one can expect to see more examples of partial or secondary ventilation air uses in new settings where physical and economic conditions are conducive to establishing a facility based on the primary fuel, and where the use of ventilation air is ancillary.

6.2 Technical Feasibility of the Principal Use of Ventilation Air without Supplemental Fuel

Two ventilation air processors identified in the report are in somewhat different stages of development. MEGTEC's TFRR (VOCSIDIZER) is in use at over 600 locations throughout the world, but only one facility operated exclusively on ventilation air, and the results of that demonstration are not yet available. Several of MEGTEC's other units operate intermittently on dilute natural gas when concentrations of target compounds (i.e., industrial volatile organic compounds) are insufficient to maintain the reaction. CANMET's CFRR, developed expressly for mine ventilation air, is operating at bench scale and will go into an industrial scale demonstration early in 2000. U of U analysts performed a technical assessment of these two reactors using numerical modeling, and they were able to draw significant conclusions:

- Both technologies are technically able to oxidize dilute methane in ventilation air.

- Both technologies will produce useable energy from a heat exchanger operating at a useful temperature range.

- CFRR and TFRR modeling results favored the CFRR, primarily because it can sustain operation at a lower concentration. However, MEGTEC has supplied field data showing that their TFRR will be autothermic at similarly low methane concentrations.

- Whichever unit has a lower autothermal concentration limit will recover a somewhat higher percentage of useable energy from the reactor.

These independent observations, coupled with the fact that flow-reversal reactors have operated successfully, give confidence that regenerative flow-reversal technology with or without a catalyst will achieve success during commercial-scale field trials using actual mine ventilation air.

6.3 Economic Viability of Flow-Reversal Reactors

Section 5 of this report presented two preliminary economic analyses of project scenarios using a flow-reversal reactor coupled to: (1) a gas turbine cogeneration facility, or (2) a waste heat boiler. Both hypothetical projects appeared to be in or close to the profitability range when operating in appropriate energy markets while taking advantage of modest credits for the greenhouse gas emissions that the projects would mitigate. Except for the cogeneration unfired case, the economic models showed the projects to be resilient to selected unfavorable changes in major revenue, cost, or methane supply assumptions.

A series of assumptions, and not actual field data, provided the basis for these economic studies. Therefore, it is too early to rely on them with total confidence. They are a source of hope, however, that solutions for elimination of methane emissions from ventilation air shafts may be affordable in the near future.

6.4 Impact of Carbon Credits

It is useful to consider the implications of the assumed value of carbon credits with respect to the economic modeling conducted for this analysis. In the fired cogeneration base case, including the value of carbon credits in the economic analysis results in an attractive internal rate of return of 29.3 percent. Removing those credits leaves the project with an IRR of 18.0 percent, which is less than adequate to attract investors. Therefore, the project would only move forward if one of the other cost or revenue parameters were more favorable or if a carbon credit of about $1 per Mt of CO_2 were available.

In both the thermal case and the unfired cogeneration case (base cases) project IRRs are 33.3 percent and 20.2 percent, respectively, when carbon credits are included in the economic analysis. Removing those credits, however, reduces the IRRs to 14.3 percent and 9.4 percent respectively, which are low enough to render these illustrative projects economically unattractive and too risky from the standpoint of a developer in the absence of the full $1.50 carbon credit value.

Curiously, there is good news whether project developers can move a ventilation air methane use project forward without carbon credits, or if they need to include them in their financial plan. With IRRs in the neighborhood of 25 percent, a significant number of fired cogeneration applications should be economically attractive to investors on their own, regardless of how the emerging carbon credit market develops. In addition, when that market does mature, the carbon credits accruing to both the thermal and cogeneration applications will improve the economics of many of the available projects to the degree that they are viable as well. Thus, regardless of the direction in which a carbon credit market evolves, technologically and economically feasible options for productively using ventilation air appear to be available.

APPENDIX A

TECHNICAL EVALUATION OF VENTILATION AIR OXIDATION PROCESSES

Appendix A. Technical Evaluation of Ventilation Air Oxidation Processes

The University of Utah's Chemical Engineering and Fuels Department (U of U) prepared a technical assessment of the thermal flow-reversal reactor (TFRR) and catalytic flow-reversal reactor (CFRR) chemical reactor processes using computer simulation techniques. This Appendix provides a detailed review of the numerical simulation modeling developed to perform the technical assessments.

Since operations of the thermal and catalytic flow-reversal reactors are identical, the following paragraphs describe only the CFRR model in detail. From a chemical engineering viewpoint, if a reaction takes place in a single phase it is considered homogeneous. The TFRR reaction takes place in the gas phase; therefore, the TFRR has also been called the homogeneous flow-reversal reactor. In the CFRR, the reaction takes place in the presence of a catalyst. Because the reactant resides in the gas phase and solid catalyst particles are involved, this is considered to be a heterogeneous reaction. Such distinctions, however, have no impact on the analysis of the two processes.

Reaction Stoichiometry, Equilibrium, and Thermochemistry

The stoichiometry of methane oxidation may be simply represented by the following equation:

$$CH_4 + 2O_2 \rightarrow CO_2 + 2H_2O \qquad \textbf{(1)}$$

The standard heat of reaction at any temperature can be calculated using:

$$\Delta H = -810267 + 28.41T - 25.56\times10^{-3}T^2 + 6\times10^{-6}T^3 + \frac{0.461\times10^5}{T} \quad \frac{\text{J}}{\text{mol CH}_4} \qquad \textbf{(2)}$$

The temperature dependency of the thermodynamic equilibrium constant is described by:

$$\ln K = -22.04 - \frac{0.231}{T^2} - \frac{97458}{T} + 3.417\ln T - 3.074\times10^{-3}T + 3.61\times10^{-7}T^2 \qquad \textbf{(3)}$$

The equilibrium conversion of methane is independent of the pressure of operation. For a stoichiometric feed of methane and oxygen, the equilibrium conversion at temperature T may be shown to be:

$$x_e = \frac{K^{1/3}}{1+K^{1/3}} \qquad \textbf{(4)}$$

Since the values of K range from ≈ 10^{156} at 0 °C to ≈ 10^{23} at 1600 °C, $K >> 1$ and we may conclude that $x_e \approx 1$ for all temperatures considered in this work. Thus there are no equilibrium limitations to the oxidation of methane.

Kinetics of CH_4 Oxidation

The performance of two types of catalysts for methane oxidation was investigated in this study. Anderson et al.[1] have published the kinetics of methane oxidation over base metal catalysts. They correlated the oxidation of CH_4 over supported copper chromite by:

[1] Anderson, R.B.; Stein, K.C.; Feenan, J.J.; Hofer, L.J.E. *Ind. Eng. Chem.* 1961, p 809.

$$r = A\exp\left(-\frac{E}{RT}\right)C_{CH_4} \qquad \textbf{(5)}$$

where r is the intrinsic reaction rate in gmol/(cm^3 catalyst·sec) and C_{CH_4} is the molar concentration of methane in gmol/cm^3. The values of A and E were reported to be $10^{4.87}$ sec^{-1} and 23.1 kcal/gmol, respectively. The same authors have reported the kinetics of methane oxidation over noble metal catalysts. In particular, the rate of oxidation over Pt/Al_2O_3 could also be described by a first-order rate expression with $A = 10^{7.35}$ sec^{-1} and E = 23.5 kcal/gmol.

The oxidation of methane can also take place homogeneously. Westbrook and Dryer[2] have described the global kinetics of this reaction by:

$$r = A\exp\left(-\frac{E}{RT}\right)\left[C_{CH_4}\right]^{-0.3}\left[C_{O_2}\right]^{1.3} \qquad \textbf{(6)}$$

Two sets of values have been reported for A and E/R: $A = 1.3 \times 10^8$ sec^{-1} and E/R = 24358; $A = 8.3 \times 10^5$ sec^{-1} and E/R = 15,098.

<u>Differential Material and Energy Balances for the CFRR</u>

The CFRR reactor model was developed under the following assumptions:

- Plug flow of gas, flat velocity profile across the reactor diameter, no entrance or end effects.
- Axial and radial dispersion of heat and mass are negligible.
- Intraparticle (internal) and interparticle (external) gradients of concentration and temperature are absent. Thus the global and intrinsic rates of the reaction are the same.
- The temperature and the concentration profiles of all the species are continuous across the transition from inert bed to the catalyst bed and from the catalyst bed to inert bed.
- No reaction takes place in the gas phase of the entire reactor.

Heat released due to the reaction occurring in the pellet is transferred from the surface of the pellet to the gas by convective heat transfer. Consider the reactor just before flow reversal takes place. A certain amount of gas is trapped within the reactor with a given temperature and methane concentration profile. If flow reversal is assumed to take place instantaneously and the gas flow rate is high, the volume of unreacted methane and air trapped inside will be swept out of the reactor and released immediately, and it will have no effect on the next cycle. However, the solid inert media and catalyst pellets remaining within the reactor retain their temperature profile at the end of the half-cycle, and this becomes the initial solid temperature profile for the next half-cycle.

Since no reaction takes place in the inert beds and the accumulation of methane in the void spaces is small in comparison with the methane passing through the reactor in one half-cycle, the mass balance for methane in this section need not be solved.

The following equations describe the energy balance for the CFRR's inert beds. For each of the beds (inert or catalytic) there are mass and energy balances. The mass balance addresses only the methane while the energy balances are on the gas and on the solids.

[2] Westbrook, C.K.; Dryer, F.L. *Combustion Science. and Tech.* 1991, 79, p 97

Energy Balance
Gas phase

$$\frac{\partial T^*}{\partial t^*} + \frac{\partial T^*}{\partial z^*} = \alpha_i \left(T_i^* - T^*\right) \tag{7}$$

Solid phase

$$\frac{\partial T_i^*}{\partial t^*} = -\beta_i \left(T_i^* - T^*\right) \tag{8}$$

Catalytic bed
Equation 9 describes the CFRR's mass balance on methane in the gas phase.

$$\frac{\partial x}{\partial t^*} + \frac{\partial x}{\partial z^*} = \delta r_g \tag{9}$$

Energy balance
Gas phase

$$\frac{\partial T^*}{\partial t^*} + \frac{\partial T^*}{\partial z^*} = \alpha_c \left(T_c^* - T^*\right) \tag{10}$$

Solid phase

$$\frac{\partial T_c^*}{\partial t^*} = \gamma r_g - \beta_c \left(T_c^* - T^*\right) \tag{11}$$

The nondimensional variables are:

$$x = \frac{C_{CH_4}^0 - C_{CH_4}}{C_{CH_4}}, \quad T^* = \frac{T}{T_0}, \quad T_c^* = \frac{T_c}{T_0}, \quad z^* = \frac{z}{L}, \quad t^* = \frac{t}{\theta} \tag{12}$$

The model parameters are:

$$\alpha = \frac{h_c \bar{a} \theta}{\rho_g C_{pg}} \frac{1-\varepsilon_b}{\varepsilon_b}, \quad \beta = \frac{h_c \bar{a} \theta}{\rho_s C_{ps}}, \quad \gamma = \frac{\left(-\Delta H\right)\theta}{\rho_s C_{ps} T_0}, \quad \delta = \frac{\theta}{C_{CH_4}^0} \frac{1-\varepsilon_b}{\varepsilon_b}, \quad \theta = \frac{L}{u_s} \tag{13}$$

Equations are coupled hyperbolic partial differential equations (PDEs). To solve the PDEs, we need three initial conditions and three boundary conditions for x, T^*, and T_c^*. They are as follows:

Initial conditions:

$$\begin{aligned} x(z,0) &= 0 \\ T^*(z,0) &= 1 \\ T_c^*(z,0) &= \text{solid temperature profile from the previous cycle} \end{aligned} \tag{14}$$

Boundary conditions:

$$\begin{aligned} x(0,t) &= 0 \\ T^*(0,t) &= 1 \end{aligned} \tag{15}$$

The set of initial and boundary conditions are consistent.

Differential Material and Energy Balances for the Homogeneous Reactor

Inert beds

Energy balance

Gas phase

$$\frac{\partial T^*}{\partial t^*} + \frac{\partial T^*}{\partial z^*} = \alpha_i \left(T_i^* - T^*\right) \quad \textbf{(16)}$$

Solid phase

$$\frac{\partial T_i^*}{\partial t^*} = -\beta_i \left(T_i^* - T^*\right) \quad \textbf{(17)}$$

Homogeneous reactor

Gas phase mass balance

$$\frac{\partial x}{\partial t^*} + \frac{\partial x}{\partial z^*} = \delta r_g \quad \textbf{(18)}$$

Gas phase energy balance

$$\frac{\partial T^*}{\partial t^*} + \frac{\partial T^*}{\partial z^*} = \gamma r_g \quad \textbf{(19)}$$

The initial and boundary conditions remain the same as those for the catalytic case (equations (14) and (15)).

Data Required

The reactor model as developed requires input data. The data requirements and equations used are explained in this section.

- Pressure of the feed gas. The pressure drop through the reactor is estimated using the Ergun equation[3]:

$$\frac{\Delta P}{L} = -\frac{G_m}{\rho_g d_p} \frac{1-\varepsilon_b}{\varepsilon_b^3} \left[\frac{150(1-\varepsilon_b)\mu}{d_p} + 1.75 G_m \right] \quad \textbf{(20)}$$

The inlet pressure is set at $P_0 = P_{exit} + \Delta P$ Pa.

- Initial temperature of the feed gas (K).
- Temperature profiles of the gas and solid phases (K).
- Initial composition of CH_4 (in volume %).
- Volumetric flow rate of the feed gas under standard conditions (25 °C, 1 atm), V_0 m^3/s.

[3] Bird, R.B.; Stewart, W.E.; Lightfoot, E.N. *Transport Phenomena, Wiley and Sons,* 1960.

- Length of the three sections: L_1, L_2, L_3; $L = L_1 + L_2 + L_3$ (m).
- Diameter of the reactor, d_t (m).
- Diameter of the solid pellets in the inert and catalytic sections, d_{pi} and d_{pc}, (m).

Physical Properties[4]

Gas phase

Concentration of methane in the feed: $$C_{CH_4}^0 = \frac{y_0}{100}\frac{P}{R_g T} \quad \frac{\text{kmol}}{\text{m}^3}$$

Density: $$\rho_g = \frac{PM}{R_g T} \quad \frac{\text{kg}}{\text{m}^3}$$

where R_g = 8314 Pa·m^3/(kmol·K), M = 28.966 kg/kmol

Viscosity: $$\mu = \frac{1.425\times 10^{-6} T^{0.5039}}{1+108.3/T} \quad \frac{\text{kg}}{\text{m}\cdot\text{s}}$$

Thermal conductivity: $$k_{th,g} = \frac{3.1417\times 10^{-4} T^{0.7786}}{1-0.7116/T+2121.7/T^2} \quad \frac{\text{W}}{\text{m}\cdot\text{K}}.$$

Specific heat capacity: $$\frac{C_{pg}M}{R_g} = 3.355 + 0.575\times 10^{-3} T - \frac{0.016\times 10^5}{T^2} \quad \frac{\text{J}}{\text{kg}\cdot\text{K}}$$

Flow rate: $$u_s = \frac{V}{A_c}\frac{T_0}{273.15}\frac{101{,}325}{P_0} \text{ m/s}$$

Mass velocity: $$G_m = \rho_g u_s = \text{constant}$$

The temperature-dependent gas-phase properties are evaluated at the average of the inlet gas temperature and the maximum temperature, T_{max}, which is the sum of the initial catalyst temperature and the adiabatic temperature rise:

$$\Delta T_{ad} = \frac{(-\Delta H)y_0}{22.4 G_m C_{pg}} \qquad \textbf{(21)}$$

Solid phase

Inert beds:

Density: ρ_i = 4070 kg/m^3

[4] Perry, R.H.; Green, D.; editors *Perry's Chemical Engineering Handbook, Sixth Ed.* McGraw Hill,1994.

Specific heat capacity: C_{pi} = 910 J/(kg·K)

Catalyst beds:

Density: ρ_c= 1250 kg/m^3

Specific heat capacity: C_{pc} = 1060 J/(kg·K)

The specific surface area is given by:

$$\bar{a}_j = 6/d_{pj} \quad \text{m}^2/\text{m}^3 \tag{22}$$

The bed voidage may be predicted using:

$$\varepsilon_{bj} = 0.39 + 0.07\left(\frac{d_{pj}}{d_t}\right) + 0.54\left(\frac{d_{pj}}{d_t}\right)^2 \tag{23}$$

The heat transfer coefficient was found using the *j*-factor analogy between heat and mass-transfer for packed beds:

$$h_{c,j} = 0.458\frac{\rho_g C_{pg}}{\varepsilon_{bj}}\left(\frac{d_{pj}G_m}{\mu}\right)^{-0.407}\left(\frac{C_{pg}\mu}{k_{th,g}}\right)^{-2/3} \quad \text{W/(m·K)} \tag{24}$$

In equations (22) to (24), subscript *j* refers to the catalytic section (*c*) or the inert section (*i*). The rate expressions are also expressed in nondimensional form. Equations (5) and (6) become:

$$r = \exp\left[\eta - \pi\left(\frac{1}{T_c^*} - 1\right)\right]C_{CH_4}^0 (1-x)\frac{1}{T_c^*}\frac{P_0}{P} \quad \frac{\text{kmol}}{\text{m}^3 \cdot \text{s}} \tag{25}$$

$$r = \exp\left[\eta - \pi\left(\frac{1}{T_c^*} - 1\right)\right]C_{CH_4}^0 \frac{(\sigma - x)^{1.3}}{(1-x)^{0.3}}\frac{1}{T^*}\frac{P_0}{P} \quad \frac{\text{kmol}}{\text{m}^3 \cdot \text{s}} \tag{26}$$

where $\pi = E/R_g T_0$ and $\eta = \ln A - \pi$. In equation (26), σ is the ratio of the molar flow rate oxygen to that of methane in the feed.

These coupled partial differential equations with the appropriate boundary conditions were solved using a numerical procedure called the Method of Lines. All of the computer programs for the solution were developed at the University of Utah.

Parameters Used

Reactor length = L = 1.5 m

Bed heat capacity = r_s C_{ps} = 1,360,000 J/(m^{3}K)

Volumetric heat transfer coefficient = $h_c \cdot \underline{a}$ = 100,000 W/(m^{3}K)

Bed void fraction = e_b = 0.65

Cycle time = t_{cyc} = 200 seconds (the flow is reversed every 100 seconds)

Inlet gas temperature = 20°C

Superficial gas velocity = u_s = 0.7 m/s (interstitial velocity = 0.7/0.65 = 1.08 m/s)

Rate law = $r = 2.53\times10^{10}\cdot\exp[-45000/(1.987\cdot T)]\cdot C_A$, kmol/(m^{3}s)

Inlet CH_4 concentrations = 0.06 - 1 mol%

Model Analysis

The model output was CH_4 conversion, gas-phase temperature, and solid-phase temperature, as a function of position within the reactor and time. The key difference between the models for the two reactors is the location of the reaction. In the TFRR, the reaction and heat release takes place in the gas phase, whereas in the CFRR the reaction occurs on and within the catalyst. In either case, the solid phase is the heat storage device releasing heat to the cold, incoming gas and extracting the exothermic heat of reaction from the completely converted gas. However, in the case of the CFRR, the reaction is limited to the section that houses the catalyst. On the other hand, the reaction in the TFRR takes place wherever the temperature is high enough (≈ 1000 °C).

The model parameters that govern the solution process are:

- Physical properties of the gas and solid: density, specific heat capacity.
- Reaction: rate law, heat of reaction.
- Reactor: length, voidage, diameter, specific surface area of solids per unit reactor volume (*a*).
- Operating conditions: gas flow rate, initial gas temperature, inlet CH_4 concentration, inlet solid temperature profile.
- Cycle time, t_{cyc} : the flow is reversed every $t_{cyc}/2$ seconds.

For a given system, the physical properties and reaction characteristics are fixed by the materials involved. The gas flow rate and the initial gas temperature are also fixed by process conditions. For a reactor containing a monolithic or pelletized catalyst or inert heat transfer medium, voidage and *a* are also fixed. Thus, the only parameters to be chosen are: reactor length, diameter, initial solid temperature, and cycle time. Eventually, after a certain number of cycles, a cyclic steady state is established, wherein:

- The gas exits at a temperature $T_{exit} = T_0 + T_{ad}$.
- The solid temperature profile is invariant upon flow reversal.
- The conversion is unity.

This corresponds to a successful reactor operation. The initial solid temperature profile is chosen to ensure that the process is not a *non-starter (*i.e., the reaction is initiated). The cycle time is chosen so that reactor *blow-out* does not occur. If t_{cyc} is too long, the heat front or temperature wave is carried out of the reactor leading to extinction. On the other hand, if t_{cyc} is too short, there will not be enough energy to sustain the reaction and extinction will eventually occur.

Results

Thermal Flow-Reversal Reactor

The success of the operation for various inlet CH_4 concentrations was monitored in accordance with the criteria stated previously. For each cycle, the average temperature and conversion over t_{cyc} seconds were computed by integrating the instantaneous gas-phase exit temperatures and conversions. These are plotted in Figure 1.

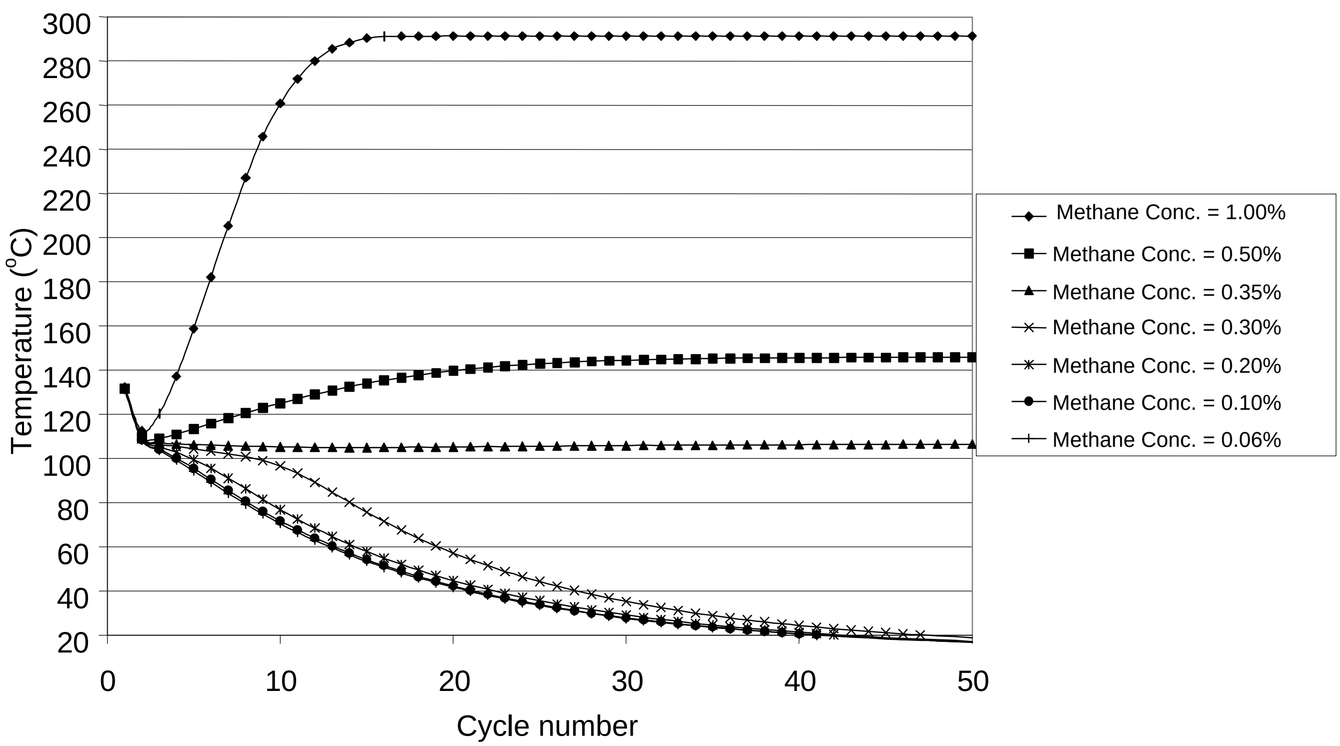

Figure 1. Exit Gas Temperature from a TFRR as a Function of Cycle Number

Figure 1 clearly shows that the operation is autothermal down to 0.35% CH_4 in the inlet. At 0.3% CH_4 and below, the exit gas temperature falls off to 20°C and the reactor is completely cool. Plots of the gas conversion for concentrations below 0.35% are shown in Figure 2, below. The conversion steadily falls to zero with increasing cycle number.

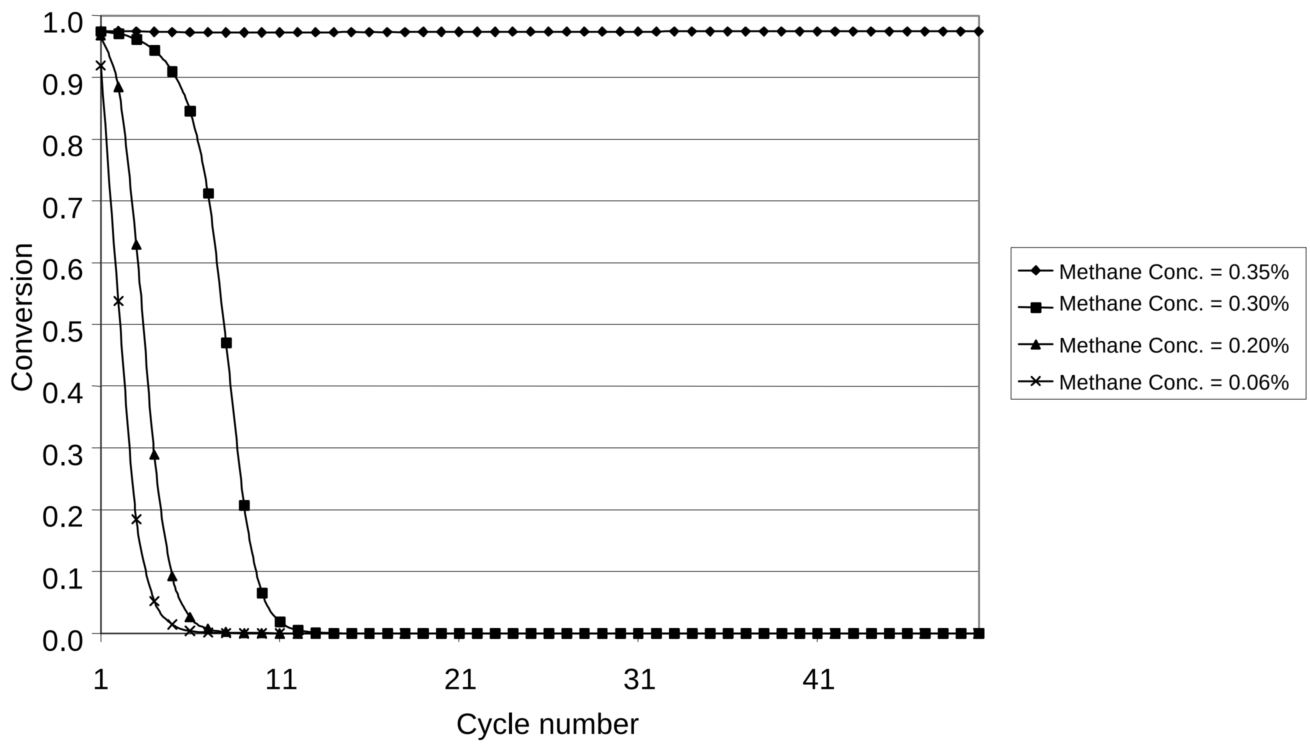

Figure 2. Exit Conversion from a TFRR as a Function of Cycle Number

Catalytic Flow-Reversal Reactor

The CFRR simulation assumed conditions identical to those employed in the TFRR analysis, except that in the CFRR simulation, the initial temperature profile was a triangular function with a maximum temperature of 425°C at the bed center. The results clearly show that the CFRR blows out only at about 0.1% CH_4 in the feed inlet (Figures 3 and 4).

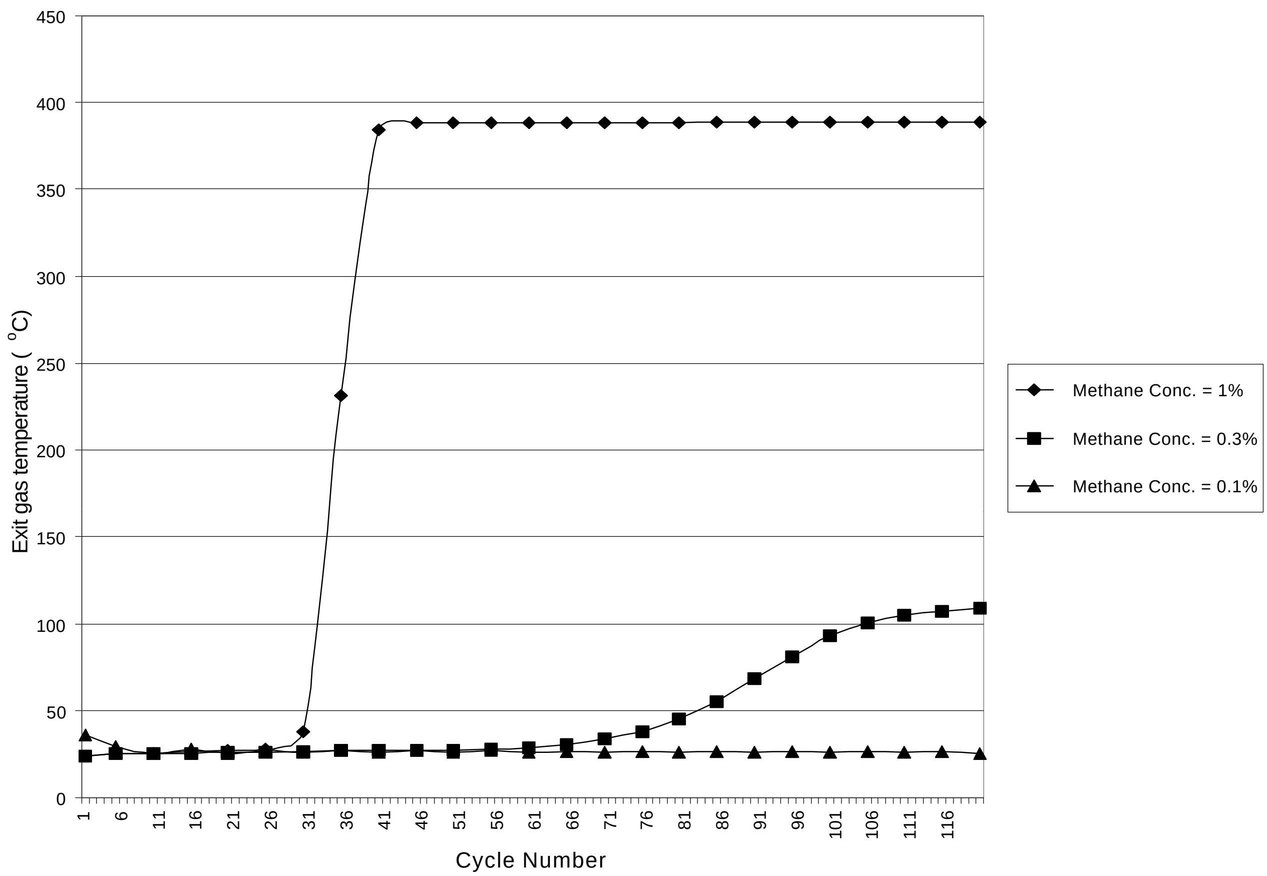

Figure 3. Exit Gas Temperature from a CFRR Modeled under the Same Conditions as the TFRR

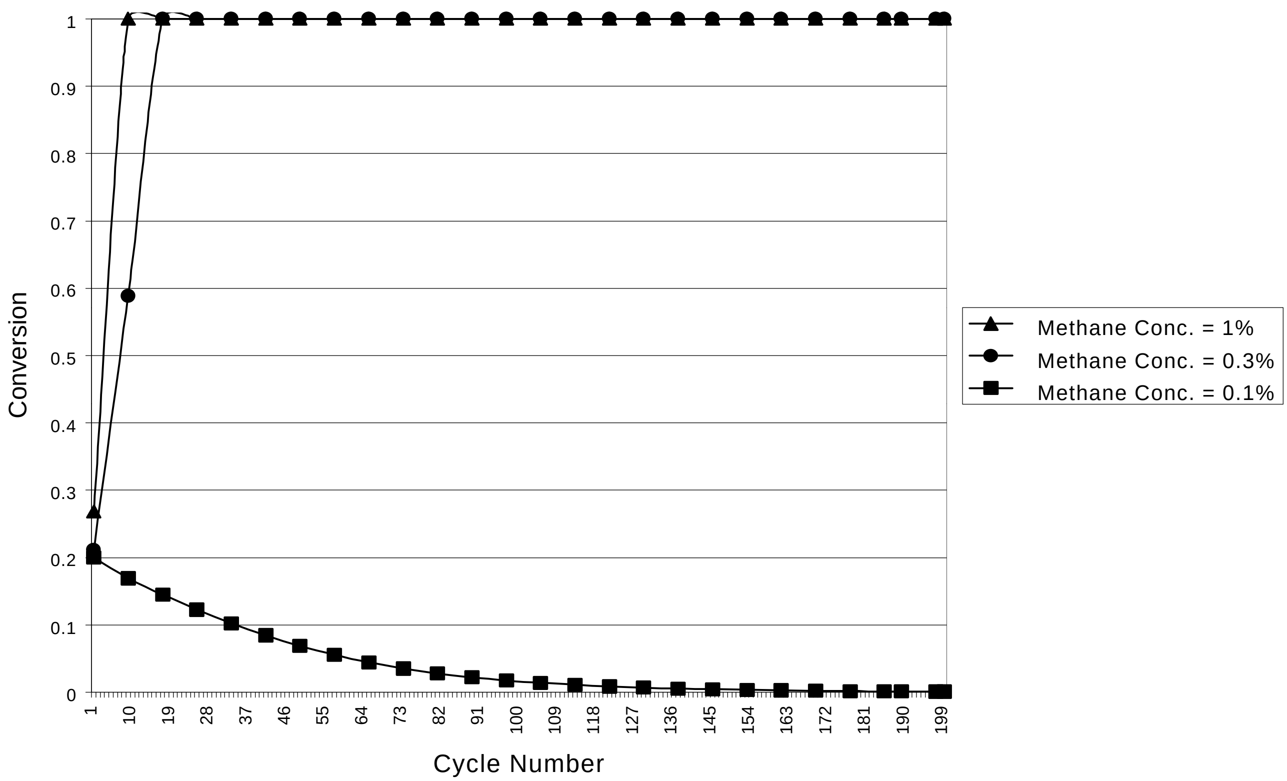

Figure 4. Exit Conversion from a CFRR Modeled under the Same Conditions as the TFRR

<u>Conclusion</u>

The University of Utah conducted computer model simulation of the TFRR and CFRR reactors under identical conditions except for the initial temperatures for both the TFRR and the CFRR. Figures 1, 2, 3, and 4 show that the TFRR requires a CH_4 concentration of 0.35% to remain autothermic, while the CFRR can remain autothermic almost to a level of 0.1% CH_4. Design assumptions could lead to differences between modeling results and field trials, so actual field trial results would be more reliable indicators of performance.

Nomenclature

A	Pre-exponential factor, s^{-1}
C	Molar concentration, $kmol/m^3$
C_{pg}	Gas-phase specific heat capacity, J/kmol K
C_{ps}	Solid-phase specific heat capacity, J/kmol K
d_p	Particle diameter, m
E	Activation energy, J/kmol
G_m	Gas mass velocity, kg/s
h_c	Heat transfer coefficient, W/m^2K
K	Thermodynamic equilibrium constant, (-)
L	Length of the reactor, m
r	Volumetric rate of reaction, $kmol/m^3s$
R_g	Universal gas constant, J/kmol K
T_0	Inlet gas temperature, K
T_g	Gas-phase temperature, K
T_s	Solid-phase temperature, K
u_s	Superficial velocity, m/s
x	Conversion, (-)
x_e	Equilibrium conversion, (-)
ΔH	Standard heat of reaction, J/kmol
ΔT_{ad}	Adiabatic temperature rise, K
$\alpha, \beta, \gamma, \delta, \theta$	See equation 13
ε_b	Bed voidage, (-)
μ	Gas-phase viscosity, Pa-s
η	ln A - π
π	E/R_gT_0
σ	Ratio of O_2 in feed to CH_4 in feed, (-)
ρ_g	Gas-phase density, kg/m^3
ρ_s	Solid-phase density, kg/m^3
ρ_c	Catalyst density, kg/m^3
ρ_I	Inert solid-phase density, kg/m^3

APPENDIX B

INDUSTRY CONTACTS

Appendix B. Industry Contacts

The following firms and individuals supplied information for this report and may be contacted for further details:

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Chalmers University, Goteborg, Sweden

Bjorn Heed	Assoc. Professor	46 31 7721426 email: heed@entek.chalmers.se

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APPENDIX C

SAMPLING OF GAS TURBINE MODELS

Appendix C. Sampling of Gas Turbine Models

The following list of commercial combustion turbine products includes both new and old models. The authors have not examined the suitability of any models for a ventilation air project. The list is offered merely to present a sample of the variety of models that are available. This list is arranged according to nominally rated output in megawatts.

Source: EPRI (in *Power Engineering*, March 1999); Solar Turbines; and personal communications.

< 10 MW	
1.4 MW	Heron H-1
1.5 MW	Dresser-Rand
1.6+ MW	OPRA OP-16R
2.0+ MW	P&W ST18 Upgrade
2.5+ MW	Orendo OGT 2500R
2.6 MW	Aviadvigatel GTU-2.5P
2.7+ MW	Nuovo Pigone PGT-2 IC
3.4 MW	Solar Centaur 40
3.5 MW	P&W ST30
3.6 MW	EGT Typhoon
3.8 MW	Allied Signal ASE SO
4.2 MW	Solar Mercury 50 ATS
4.7 MW	EGT Typhoon
4.8 MW	Solar Taurus 60
5.2+ MW	Allison 501-KB7
5.3 MW	MAN GHH THM1203
5.3 MW	EGT Typhoon
6.5 MW	Sulzer Escher Wyss S3
6.7 MW	Allison 601-KB9
7.0 MW	Kawasaki M7A-01
8.2 MW	Allison 601-KB11
8.9 MW	MAN GHH THM1304-9
9.0 MW	Solar Mars 90
9.8 MW	Allied Signal ASE 120

11 – 20 MW	
11.0 MW	Sulzer Escher Wyss S7
11.1 MW	CHAT-KM7
11.2 MW	Nuovo Pignone PGT 10B
12.0 MW	ICAD 2-shaft
12.9 MW	EGT Cyclone
13.2 MW	Solar Titan
13.4 MW	GE LM1600PA
13.5 MW	Allison 701-K
15.0 MW	ICAD 3-shaft
17.9 MW	Solar ATS “L”
19.8 MW	Northrop WR-21

APPENDIX D

TYPICAL SPREAD-SHEET MODEL FOR ALLOCATION OF GOB GAS

Appendix D. Typical Spread-Sheet Model for Allocation of Gob Gas

ALLOCATION OF GOB GAS: REACTOR versus TURBINE
0.5% Concentration by Volume

Case 6. 20% Gob Gas to Reactor

<u>Assumptions</u>

Vent air flow	212,000 cfm
Methane content	0.5%
Methane heat value	1000 Btu/cu ft
Gob gas flow (methane)	868 cfm
Percent gob gas to reactor	20%
Turbine compressor exit temperature	572 ^oF
Reactor exit temperature	1300 ^oF
Turbine rotor inlet design temperature	1832 ^oF

CALCULATE HEAT FROM REACTOR

Vent air flow (0.5% methane)	212,000 cfm
Air flow	210,940 cfm
Methane flow	1060 cfm
Gob gas flow to reactor	174 cfm
Total methane flow to reactor	1234 cfm
Total heat to reactor	1,465,364 Btu/min
Methane concentration	0.58 %
Recovery rate (from Figure 6)	82.5 %
Heat recovered from reactor	1,208,925 Btu/min
	72.54 mmBtu/hr
Mass flow through reactor	6,916 lb/min
	115.27 lb/sec
Heat to power turbine	2,157,840 Btu/min
	129.47 mmBtu/hr

CALCULATE POWER GENERATED FROM TURBINE

Heat from reactor	2,157,840 Btu/min
Heat from gob gas	694,400 Btu/min
Total heat to power turbine	2,852,240 Btu/min
	171.13 mmBtu/hr
Total mass to turbine	6946 lb/min
Temp inlet to turbine rotor	1711 ^oF
Degrees below turbine rotor inlet design temperature	121 ^oF
Turbine efficiency (from Figure 8)	29.1 %
Turbine Output	**14,591 kW ($_e$)**

ALLOCATION OF GOB GAS: REACTOR versus TURBINE
0.5% Concentration by Volume

SUMMARY OF CASES

Table 1. Heat to Turbine

	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8	Case 9
% Gob Gas to Reactor	0%	100%	75%	50%	25%	20%	15%	10%	0%
% Gob Gas to Turbine	0%	0%	25%	50%	75%	80%	85%	90%	100%
% Heat Recovered	80%	89%	87.50%	85.70%	83.30%	82.50%	82%	81.50%	80%
Total Heat Recovered - mmBtu/hr	62.11	115.33	102.00	88.74	75.41	72.54	69.96	67.41	62.00
Total Heat to Turbine - mmBtu/hr	110.67	205.86	182.05	158.39	134.60	129.47	124.87	120.32	110.67

Table 2. Electrical Power from Turbine

	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8	Case 9
Total Heat from Reactor - mmBtu/hr	110.67	205.86	182.05	158.39	134.60	129.47	124.87	120.32	110.67
Heat from Gob Gas - mmBtu/hr	0.00	0.00	13.02	26.04	39.06	41.66	44.27	46.87	52.08
Total Heat to Turbine - mmBtu/hr	110.67	205.86	195.07	184.43	173.66	171.13	169.14	167.20	162.75
Temperature at Turbine - ^oF	1300	1300	1392	1510	1671	1711	1753	1797	1900
Turbine Efficiency - %	20.0%	20.0%	22.2%	24.8%	28.4%	29.1%	29.6%	29.9%	30.0%
Power Produced - $kW_{(e)}$	6,485	12,063	12,689	13,402	14,450	14,591	14,669	14,623	14,306

APPENDIX E

ILLUSTRATIVE ECONOMIC MODELS

Appendix E. Illustrative Economic Models

E - 1: Comparison of a 125 MW Mine-Mouth Coal Plant with a Traditionally Sited 125 MW Plant (Page 1 of 1)

Mine Data		*mmcfd*	*mcf/h*
Vent methane flow		2.00	83.33
Vent methane concentration	0.005		
Vent air flow		400	
Gob gas available		2.00	83.33

Mine-Mouth Coal Plant Assumptions	
Capacity - kW	125,000
Heat rate - Btu/kWh	10,000
Length TM line - miles	30
NOx emission - lb/mmBtu	0.45
NOx reduction - per % methane	5%
Availability - hr/yr	7,446
CH4 destroyed - Mt/h	3.21
CO2 equivalent - Mt/h	67.43

Capital Cost Assumptions	
Trad coal plant cap cost $/kW	1,400
Labor % of plant cost	0.4
Remote labor, premium	0.15
Remote plant labor adder $/kW	84
TM cost $/mile	200,000
TM line adder $/kW	48
Dry tower cost $/kW	2.5
Mine mouth add'l cap cost $/kW	134.50
Mine Mouth extra capital cost	16,813

Operating Cost Assumptions	
Annual production mmkWh/yr	930.75
NOx cost $/ton	2000
Dry tower derate: % of 3 cents	2%
Nom. cost baseline power $/kWh	0.03

Mine Mouth Fuel Mix	*Fraction*
Vent methane	0.067
Gob gas	0.067
Coal	0.867

Mine Mouth Unit Fuel Cost	*$/mmBtu*
Coal cost	1.40
Coal freight cost	0.14
Net coal cost	1.26
Gob gas cost	0.60
Vent methane cost	0.00

Fuel Cost per kWh	*$/kWh*
Trad. Plant-Coal 100%	0.014
MM Plant - Coal fract.	0.01092
MM Plant,VA methane	0
MM Plant - Gob gas	0.0004
MM Plant - composite	0.01132

NOx Credits	
lb's NOx emitted/kWh	0.0045
MM Plant reduc. fract.	0.6667
MM Plant red. Lb/kWh	0.003
NOx red. Value/kWh	0.003

Dry Tower Derate	*$/kWh*
Cost per kWh	-0.0006

Total Oper Cost Changes	*$/kWh*
Fuel cost savings	0.00268
NOx credit	0.003
Dry tower derate	-0.0006
CO2 credit	0.000809
Total	0.005889

Carbon Credits		
CO2 reduction	*Mt/kWh*	0.000539
CO2 credit value	*$/Mt*	1.50
CO2 credit /kWh	*$/kWh*	0.000809

Sensitivity: (base case bold)		
TM line	*miles*	*IRR*
	10	41.45%
	20	35.19%
	30	**30.29%**
	40	26.32%
Gob gas	*mmcfd*	
	1.00	22.75%
	2.00	**30.29%**
	3.00	37.47%
Derate	*%*	
	0	34.00%
	2	**30.29%**
NOx cr.	*$/ton*	
	0	9.60%
	1000	20.55%
	2000	**30.29%**
	3500	43.87%
CO^2 cr.	*$/Mt*	
	0.00	25.14%
	0.50	26.88%
	1.00	28.59%
	1.50	**30.29%**
	2.00	31.97%
Best Case		78.29%

DISCOUNTED CASH FLOW ANALYSIS **($000's)**

Year	0	1	2	3	4	5	6	7	8	9	10
Cash Flow: incremental investment and annual savings.	16,813	-5,481	-5,481	-5,481	-5,481	-5,481	-5,481	-5,481	-5,481	-5,481	-5,481
Simple IRR	30.29%										

E - 2: Electricity Generation Using Either TFRR or CFRR (Page 1 of 3)

Mine Data		mmcfd	mcf/h	m^3/s	mmcfd	mcf/h	m^3/s
Vent air flow		305	12,708	100	305	12,708	100
CH4 concentration	0.005		***fired***			***unfired***	
Vent air methane		1.53	63.54	0.50	1.53	63.54	0.50
Gob gas available		1.25	52.08	0.41	0.60	25.00	0.20
Gob gas to reactor		0.50	20.83	0.16	0.60	25.00	0.20
Gob gas to turbine		0.75	31.25	0.25	0.00	0	0
Operating Assumptions		%	mmBtu/h	Gj/h	%	mmBtu/h	Gj/h
Enhanced concentration		0.0066			0.0070		
Fuel => reactor			84.38	88.95		88.54	93.34
Reactor heat recovery %		0.785			0.808		
Reactor heat rec =>GT			66.21	69.80		71.52	75.39
Total heat => GT if fired			97.46	102.74			
Air mass thru heat exch	kg/s		53.11			55.74	
Gross elec potential unfired	kW(e)					4,610	
Gross elec potential fired	kW(e)		7,996				
Booster fan power draw	kW(e)		650			650	
Misc parasitic power draw	kW(e)		450			450	
Electric capacity purchased	kW(e)		7,996			5,993	
Elec cap net	kW(e)		6,896			3,510	
Thermal capacity	kW(t)		10,896			11,434	
Operating hours/year	90%		7,884			7,884	
Thermal market hours/year	75%		6,570			6,570	
Electricity sold/year	mmkWh(e)		54.37			27.67	
Heat sold/year	mmkWh(t)		71.59			75.12	
Methane destroyed	Mt/h		2.227			1.706	
CO2 equiv destroyed	Mt/h		46.78			35.82	
Total CO2 mitigated	Mt/y		368,792			282,408	
Revenue and Cost Assumptions							
Thermal price	$/kWh(t)	0.01					
Elect price	$/kWh(e)	0.035					
Carbon credit	$/Mt	1.50					
Gob gas fuel	$/mmBtu	0.60					
Gob gas fuel	$/yr		246			118	
TG maint	$/kWh	0.0035					
Misc oper & OH cost	$000/yr		267			225	
Reactor capital cost	$000/proj		3,150			3,150	
Power plant cap cost	$000/proj		5,197			3,895	
Installed cap cost	$000/proj		8,347			7,045	
Project "soft" costs	%	25%					
Total capital cost	$000/proj		10,434			8,807	
Financial Assumptions							
Project term - years	12						
Loan-% of capital cost	70%	Loan amt	7,304			6,165	
Interest rate	10%						
Loan term - years	8						
Escalation - %/year	2.5%						

E - 2: Electricity Generation Using Either TFRR or CFRR (Page 2 of 3)

Cash Flow Analysis-unfired

Year	0	1	2	3	4	5	6	7	8	9	10	11	12
REVENUES													
Electric		969	993	1,018	1,043	1,069	1,096	1,123	1,151	1,180	1,210	1,240	1,271
Thermal		751	770	789	809	829	850	871	893	915	938	962	986
Carbon credits		424	434	445	456	468	479	491	504	516	529	542	556
Total Revenue		2,143	2,197	2,252	2,308	2,366	2,425	2,486	2,548	2,611	2,677	2,744	2,812
COSTS													
O & M Costs		-322	-330	-339	-347	-356	-365	-374	-383	-393	-403	-413	-423
Fuel cost - gob gas		-118	-121	-124	-127	-131	-134	-137	-141	-144	-148	-151	-155
Interest		-616	-563	-503	-438	-366	-287	-201	-105				
Depreciation		-705	-1,268	-1,015	-812	-812	-812	-812	-812				
Total Cost		-1,762	-2,282	-1,981	-1,724	-1,664	-1,597	-1,523	-1,440	-537	-550	-564	-578
Income Before Tax		382	-85	271	584	702	828	963	1,107	2,075	2,127	2,180	2,234
Fed/State income tax	38%	-145	32	-103	-222	-267	-314	-366	-421	-788	-808	-828	-849
AFTER TAX INCOME		237	-53	168	362	435	513	597	687	1,286	1,318	1,351	1,385
CASH FLOW ADJUSTMENT													
Depreciation		705	1,268	1,015	812	812	812	812	812				
Principal Payback		-539	-593	-652	-717	-789	-868	-955	-1,050				
CASH FLOW	-2,642	402	622	530	456	457	457	453	448	1,286	1,318	1,351	1,385
CASE IRR	20.2%												
Loan Coverage		1.45	1.64	1.57	1.51	1.51	1.51	1.51	1.51				
Deprec 150%, 0.5 yr, 7.5yr		0.1000	0.1800	0.1440	0.1152	0.1152	0.1152	0.1152	0.1152				

E - 2: Electricity Generation Using Either TFRR or CFRR (Page 3 of 3)

Cash Flow Analysis-fired

Year	0	1	2	3	4	5	6	7	8	9	10	11	12
REVENUES													
Electric		1,903	1,950	1,999	2,049	2,100	2,153	2,207	2,262	2,318	2,376	2,436	2,497
Thermal		716	734	752	771	790	810	830	851	872	894	916	939
Carbon credits		553	567	581	596	611	626	642	658	674	691	708	726
Total Revenue		3,172	3,251	3,332	3,416	3,501	3,589	3,678	3,770	3,865	3,961	4,060	4,162
COSTS													
O & M Costs		-457	-469	-481	-493	-505	-518	-530	-544	-557	-571	-586	-600
Fuel cost - gob gas		-246	-253	-259	-265	-272	-279	-286	-293	-300	-308	-315	-323
Interest		-730	-667	-596	-519	-434	-340	-238	-124				
Depreciation		-835	-1,503	-1,202	-962	-962	-962	-962	-962				
Total Cost		-2,269	-2,890	-2,538	-2,238	-2,172	-2,098	-2,015	-1,923	-857	-879	-901	-923
Income Before Tax		903	361	795	1,177	1,329	1,490	1,663	1,848	3,007	3,082	3,159	3,238
Fed/State income tax	38%	-343	-137	-302	-447	-505	-566	-632	-702	-1,143	-1,171	-1,201	-1,231
AFTER TAX INCOME		560	224	493	730	824	924	1,031	1,146	1,864	1,911	1,959	2,008
CASH FLOW ADJUSTMENT													
Depreciation		835	1,503	1,202	962	962	962	962	962				
Principal Payback		-639	-703	-773	-850	-935	-1,029	-1,131	-1,245				
CASH FLOW	-3,130	756	1,024	922	841	850	857	861	863	1,864	1,911	1,959	2,008
CASE IRR	29.3%												
Loan Coverage		1.73	1.93	1.86	1.81	1.82	1.83	1.84	1.84				

E - 3: Steam Generation Only with Either TFRR or CFRR (Page 1 of 2)

Mine Data		mmcfd	mcf/h	m^3/s
Vent air flow		305	12,708	100
CH_4 concentration	0.005			
Vent air methane		1.53	63.54	0.50
Gob gas available		0.76	31.77	0.25
Operating Assumptions		mmBtu/h	Gj/h	
Enhanced concentration	0.0075			
Fuel => reactor		95.31	100.48	
Reactor heat recovery %	0.845			
Reactor heat rec =>boiler		80.54	84.90	
Booster fan power draw	kW(e)	650		
Misc parasitic power draw	kW(e)	250		
Air mass thru heat exch	kg/s	117.60		
Thermal output	kW(t)	18,878		
Thermal market hours/year	90%	7884		
Heat sold/year	mmkWh(t)	148.84		
Methane destroyed	Mt/h	1.836		
CO2 equiv destroyed	Mt/h	38.56		
Total CO2 mitigated	Mt/y	304,004		
Revenue and Cost Assumptions				
Thermal price	$/kWh(t)	0.010		
Carbon credit	$/Mt	1.50		
Gob gas fuel	$/mmBtu	0.60		
Gob gas fuel	$/yr	150		
Power cost	$/kWh	0.05		
Misc oper & OH cost	$000/yr	131		
Reactor capital cost	$000/proj	3,150		
Waste heat boiler complete	$000/proj	944		
Installed cap cost	$000/proj	4,094		
Project "soft" costs	%	25%		
Total capital cost	$000/proj	5,117		
Financial Assumptions				
Project term - years	12			
Loan-% of capital cost	70%	Loan amt	3,582	
Interest rate	10%			
Loan term - years	8			
Escalation - %/year	2.5%			

E- 3: Steam Generation Only with Either TFRR or CFRR (Page 2 of 2)

Cash Flow Analysis

Year	0	1	2	3	4	5	6	7	8	9	10	11	12
REVENUES													
Thermal		1,488	1,526	1,564	1,603	1,643	1,684	1,726	1,769	1,813	1,859	1,905	1,953
Carbon credits		456	467	479	491	503	516	529	542	556	569	584	598
Total Revenue		1,944	1,993	2,043	2,094	2,146	2,200	2,255	2,311	2,369	2,428	2,489	2,551
COSTS													
O & M Costs		-636	-652	-668	-685	-702	-720	-738	-756	-775	-794	-814	-835
Interest		-358	-327	-292	-255	-213	-167	-117	-61				
Depreciation		-409	-737	-590	-472	-472	-472	-472	-472				
Total Cost		-1,404	-1,716	-1,550	-1,411	-1,387	-1,358	-1,326	-1,289	-775	-794	-814	-835
Income Before Tax		541	277	493	683	760	842	929	1,022	1,594	1,634	1,675	1,717
Fed/State income tax	38%	-205	-105	-187	-259	-289	-320	-353	-389	-606	-621	-636	-652
AFTER TAX INCOME		335	172	305	423	471	522	576	634	988	1,013	1,038	1,064
CASH FLOW ADJUSTMENT													
Depreciation		409	737	590	472	472	472	472	472				
Principal Payback		-313	-345	-379	-417	-459	-504	-555	-610				
CASH FLOW	-1,535	431	564	516	478	484	489	493	495	988	1,013	1,038	1,064
CASE IRR	33.3%												
Loan Coverage		1.64	1.84	1.77	1.71	1.72	1.73	1.73	1.74				
Deprec 150%,.5,7.5yr		0.1000	0.1800	0.1440	0.1152	0.1152	0.1152	0.1152	0.1152				

APPENDIX F

CO_2 EMISSION TRADING

Appendix F. CO_2 Emission Trading

Opportunities are developing to enhance profitability of alternative energy projects by using greenhouse gas (GHG) credits trading. Because methane has approximately 21 times the global warming effect of carbon dioxide on the basis of weight, projects that capture and destroy methane in mine ventilation air have the potential for significant reduction of GHG emissions. CO_2 emission reductions result from destroying, while beneficially using, the methane contained in ventilation air instead of allowing it to be released into the atmosphere. The great global warming potential of coal mine methane makes ventilation air capture projects valuable in terms of GHG credits. A project developer may be able increase profits by selling to a third party greenhouse gas credits from a project that captures and destroys ventilation air employing either ancillary or primary use technology.

While the criteria governing a national and international greenhouse gas emissions market have not been formalized, market activity has begun. At present a purchaser's lowest-cost route is through the purchase of early reduction credits on the open market through one of several brokerage firms specializing in emissions transactions.[1] Early reduction credits are beginning to be traded and may be banked by the purchaser or transferred to a third party at a later date.

Project developers may also be interested in an ongoing request for proposals (RFP) for GHG mitigation projects from TransAlta, a Canadian energy company. The company's Web site invites participants such as businesses, nongovernmental organizations, business associations, and government agencies, as well as academic and research institutions, to submit project proposals for TransAlta's 1998 GHG offset RFP in accordance with the guidelines in the proposal outline section.[2] The company prefers projects that mitigate over 250,000 metric tonnes of CO_2 annually.

The few trades known to have been completed are within the $1-3 range per metric tonne of CO_2. The following are descriptions of a few emission trades that were undertaken between 1998 and 1999.

- Ontario Hydro agreed to purchase GHG emission credits earned by a methane-powered generator to be built by Toromont Energy, Ltd. Ontario Hydro is buying credit for 290,000 metric tonnes of CO_2 equivalent from the 3.5 MW plant that flares methane gas. Ontario Hydro is also expected to receive credit for another 157,000 metric tonnes per year of CO_2 equivalent from the 3.5 MW plant, which will burn roughly 700 million cubic feet/year of methane gas to produce power. The price of the trade was undisclosed, but

[1] Two brokerage firms made presentations at the U.S.EPA Workshop on International Coal Mine Methane Business Opportunities: Projects, Services, Technologies, and Financing, on May 6, 1999 at the University of Alabama, Tuscaloosa, AL. For quotes or further details contact either Mr. Jason Bosek at Cantor Fitzgerald (212 938-4250) or Ms. Hillary Nussbaum at Natsource (212 232-5353).

[2] TransAlta's RFP appears on its website - www.transalta.com, on the community & environment page in the sustainable development section. Contact information is as follows: phone – 403 267-4746, fax – 403 267-7372, email - sustainable_development@transalta.com, address – TransAlta, Sustainable Development, Box 1900, Station "M", 110 – 12th Avenue SW, Calgary, Alberta T2P2M1 Canada.

an Ontario Hydro spokesperson was quoted in a trade newsletter, *Air Daily*, as saying, as a point of reference, that \$1-2 is a "very reasonable" price (December 8, 1998).

- Niagara Mohawk Power Corporation and Arizona Public Service Company swapped 1.75 million metric tonnes of CO_2 reductions for 25,000 metric tonnes of SO_2 in 1994. According to NATSOURCE, Inc., an over-the-counter broker of energy products, the implied CO_2 price, based on the SO_2 market value at the time of the swap, was \$2.11 per metric tonne of CO_2 equivalent.

- In one of the first international emission trades, Suncor agreed to purchase 100,000 metric tonnes of CO_2 from Niagara Mohawk Power Corporation in March 1998. Carbon emissions reductions will occur as Niagara Mohawk switches from coal to natural gas, undertakes renewable energy projects, and promotes the efficient use of energy by its customers. Suncor also has an option to purchase an additional 10 million metric tonnes of greenhouse gas reductions for up to \$6 million from Niagara Mohawk after the year 2000.

- In October 1999 the Chicago-based brokerage firm, Environmental Financial Products, LLC, arranged a transaction for GHG emission reduction credits between Ontario Power Generation, Inc. of Canada and U.S.-based Zahren Alternative Power Corporation. The price for the equivalent of 2.5 million metric tonnes of CO_2 was not disclosed. The Zahren-generated credits, starting in 1998 and ending in 2000, result from combusting landfill methane to produce electric power at its landfill gas-to-energy projects at 20 U.S. locations. Ontario's Pilot Emission Reduction Trading Program will review the trade, and the emission reductions will be reviewed by PricewaterhouseCoopers, LLP.

As this report goes to press, both Mr. Bosek and Ms. Nussbaum (see footnote 1) observe that both buyers and sellers of greenhouse gas emissions credits feel comfortable with the CO_2 price in the \$1.50 per metric tonne range for qualified projects. They both believe that this price will increase as more players enter the market.