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Utilization of Coal Mine Methane for Methanol and SCP Production

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EXECUTIVE SUMMARY

The feasibility of utilizing a biological process to reduce methane emissions from coal mines and to produce valuable single cell protein (SCP) and/or methanol as a product has been demonstrated. The quantities of coal mine methane from vent gas, gob wells, premining wells and abandoned mines have been determined in order to define the potential for utilizing mine gases as a resource. It is estimated that 300 MMCFD of methane is produced in the United States at a typical concentration of 0.2-0.6 percent in ventilation air. Of this total, almost 20 percent is produced from the four Jim Walter Resources (JWR) mines, which are located in very gassy coal seams. Worldwide vent gas production is estimated at 1 BCFD. Gob gas methane production in the U.S. is estimated to be 38 MMCFD. Very little gob gas is produced outside the U.S. In addition, it is estimated that abandoned mines may generate as much as 90 MMCFD of methane. In order to make a significant impact on coal mine methane emissions, technology which is able to utilize dilute vent gases as a resource must be developed.

Purification of the methane from the vent gases would be very expensive and impractical. Therefore, the process application must be able to use a dilute methane stream. Biological conversion of this dilute methane (as well as the more concentrated gob gases) to produce single cell protein (SCP) and/or methanol has been demonstrated in the Bioengineering Resources, Inc. (BRI) laboratories. SCP is used as an animal feed supplement, which commands a high price, about $0.11 per pound. About 100 million tons of protein feeds are utilized annually in the U.S. Tyson Foods has agreed to collaborate on the Phase II and Phase III development programs. Methanol is a commodity chemical and fuel that is produced in the U.S. in quantities of over 10 billion pounds per year with a price of about $0.09 per pound. Adequate markets for these products are already available to utilize all the coal mine methane. For example, conversion of all coal mine methane in the U.S. into SCP would produce less than 10 percent of the nation's protein feed demand.

The economics of utilizing gob gas and vent gas methane to produce SCP or methanol are quite atttractive, showing payouts of about 2 years for a typical JWR mine. An *in-situ* application of the biological process that utilizes the mine vent ducts would be even more economical. The appropriate type of bioreactor (biofilter, spray reactor, trickle-bed, etc.) for both *in-situ* and above ground applications will be defined in the Phase II studies. Phase II will also include an environmental review, design of the demonstration program, market analysis and economic projections. Phase III will involve a two year technology demonstration at the mine site.

This report details the quantities of coal mine methane produced in the U.S. by category and mine, and seeks to explain some of the issues relating to the widespread utilization of this methane as a raw material. The report focuses on the implementation of an integrated biological process for SCP and methanol production at the mine, and provides laboratory data for the conversion of dilute and intermediate gas streams. Finally, the report briefly outlines the Phase II conceptual design and cost estimate study and the Phase III demonstration at a selected JWR mine.

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INTRODUCTION

Methane has been identified as a potent greenhouse gas which has a radiative forcing potential of 50 times that of carbon dioxide (Boyer *et al.*, 1990; Blake and Rowland, 1988). The total annual methane emissions from all sources, detailed in Table 1, are estimated at 355-870 million metric tons (Rogers and Whitman, 1991). Both natural and anthropogenic sources contribute methane to the atmosphere. Atmospheric methane concentrations have doubled over the last two centuries and are currently increasing at about one percent annually, or twice the rate of increase of CO_2 (Blake and Rowland, 1988).

Table 1. Potential Annual Methane Release from Various Sources (Rogers and Whitman, 1991)

Source of CH_4	Million Metric Tons/Yr
Living Sources	
Natural Wetlands	120-200
Rice Paddies	70-170
Livestock	80-100
Termites	25-150
Solid Wastes	5-70
Biomass Burning	10-40
Oceans	1-20
Tundra	1-5
Subtotal	312-755
Fossil Fuels	
Coal Mining	10-35
Venting and Flaring	15-30
Industrial Losses	5-25
Pipeline Losses	10-20
Methane Hydrates	2-4
Volcanoes	.5
Automobiles	.5
Subtotal	43-115
TOTAL	355-870

Coal mining, particularly from underground mines, contributes significant amounts of methane to the atmosphere, up to 64 million metric tons in 1987. Fifteen percent of the world methane emissions from coal mining are emitted from U.S. coal mining operations. Methane from these sources is expected to increase to 81 million metric tons by the year 2000. Methane is explosive in air in concentrations of 5 to 15 percent. Therefore, underground mines are ventilated with large quantities of air to remove methane, which is vented to the atmosphere. Ventilation is a major mining expense, with some large mines circulating as much as 23 tons of air per ton of coal produced (Skow *et al.*, 1980).

There are three primary sources of methane from the mining of coal:

- nearly pure methane streams, obtained from the pre-mining degasification wells
- 30-98% methane, obtained from gob wells during the mining process
- 0.1-1% methane, obtained from the exhaust air streams

The total methane released with the ventilation air alone from the 180 U.S. underground coal mines is currently 110 billion cubic feet per year (110 BCFY). The largest methane emission was from an Alabama mine with 17.2 million cubic feet per day (17.2 MMCFD). The ten largest methane emitting mines average 11 MMCFD (Grau, 1987). Clearly, methane from coalbeds is a serious environmental problem, but could also be a valuable resource. This problem can only be solved effectively by converting the methane into a recoverable and useful form.

The separation of the dilute methane from the ventilation air by molecular sieves or other methods has not proven to be economical (Boyer *et al.*, 1990). Various borehole methods have been used to reduce the quantities of methane in the coal seam. Horizontal and cross-measure boreholes into the unmined areas can be used to drain methane in advance of mining (Dixon, 1989). Vertical surface wells into the fractured gob areas or into the coal seam prior to mining are also used for degasification (Diamond *et al.*, 1989). The methods usually require vacuum for effective methane extraction; consequently methane concentrations may be low. Although methane from vertical wells can often be sold as natural gas early in the life of the wells, the economics of methane recovery at current gas price are favorable only under certain conditions (Boyer *et al.*, 1990). Consequently, most of this gas is discharged to the environment today.

Systems for utilizing medium to high methane content gases are commercially available. With contaminant removal, coal mine methane may be blended into the pipeline. Alternatively, gas turbines and fuel cells can efficiently generate power from coal mine methane sources containing as little as 40 percent methane on a volume basis. Simple-cycle gas turbines range in efficiency from 15-40 percent. Fuel cells convert the methane directly into electricity by the electrochemical oxidation of the fuel.

As promising as these technologies are, they are not capable of utilizing intermediate to low quality methane. 1988 estimates from mine ventilation streams show that nearly 300 MMCFD of methane is emitted from 193 of the gassiest coal mines in the U.S. (Trevitz *et al.*, 1993). Because of the very low methane concentrations, nearly all is vented directly into the atmosphere.

Perhaps the best method for removing and utilizing methane at these intermediate to low concentrations is through biological conversion. Coal mine methane may be converted to methanol and single cell protein (SCP) by the action of methylotrophic bacteria. These bacteria produce methanol by direct oxidation of methane in a single step through the action of the enzyme methane monooxygenase. Subsequent reactions convert the methanol into cell mass which is high in protein content and can be used as an animal feed supplement.

High yields and fast rates are possible using this technology. More importantly, as is illustrated in Table 2, methanol and SCP are higher value products than either natural gas or electricity. In addition, the production of SCP represents a significant energy savings. The energy to produce soybeans (an alternative to SCP) is estimated at 11.3 million BTU/ton protein produced, while the energy to produce SCP from methane is only 6 million BTU/ton protein.

Table 2. Conversion of Methane to Various Products

Product	Yield per MCF Methane	Product Value per MCF Methane
Natural Gas	-	$1.50
Electricity	109 kwhr	3.25
Methanol	6.8 gal	4.10
SCP	44.4 lb	8.33

Research carried out at Bioengineering Resources (BRI) successfully demonstrated the technical and economic feasibility of these biotechnologies in batch and continuous reactor studies. Economic projections show a high rate of return on investment (up to a two year payout) when converting either high methane concentrations or when using dilute methane in air.

PURPOSE

The objective of this multiphase project is to evaluate and prepare a conceptual design for a demonstration of a biological process for the conversion of intermediate and low quality coal mine methane to methanol and SCP. The partners in this multiphase venture are BRI, the U.S. Bureau of Mines (USBM) and Jim Walter Resources (JWR).

The purpose of this Phase I report is to present information on the quantities of coal mine methane, the issues relating to its use and the potential for utilizing a biological process for its conversion to methanol and SCP. The quantities of coal mine methane from vent gas, gob wells, premining wells and abandoned mines are presented, along with the major problems and issues surrounding its collection and use. The potential for developing and utilizing a biological process for the conversion of dilute and concentrated coal mine methane to valuable SCP and methanol is then outlined and discussed.

Phase II will be a conceptual design and cost estimate for biological conversion. The environmental impact of the technology will be assessed. Market analyses will be performed to identify the potential markets and the strategy for commercializing methanol and SCP production from coal mine methane. Economic projections for the various commercial schemes will be prepared to identify high cost areas for concentrated research. In addition, the Phase II effort will also include bioreactor design studies to develop scale-up data for a demonstration in Phase III at JWR.

PHASE I OBJECTIVES

The objective of this multiphase project is to evaluate and prepare a conceptual design for a demonstration of a biological process for the conversion of intermediate and low quality coal mine methane to methanol and SCP. The Phase I feasibility study evaluated the available gas resource associated with underground coal mining and identified and evaluated biological conversion in comparison to other gas utilization technologies. The feasibility study also included market or mine-wide application potential for the proposed gas utilization technology. These objectives were accomplished by the completion of the following tasks.

Task 1. Determine Mine Gas Potential

Mine measurements, as well as existing DOE, EPA, USBM, USGS, MSHA, and other pertinent government/industry data and documents relevant to domestic coal mine emissions will be used to assess the magnitude of the various methane gas streams and sources associated with the proposed project operations. The available gas potential will be determined for the proposed project. The data and calculations used are required deliverables. Scientific/technical work shall be provided in a replicable form.

Task 2. Evaluate the Coal Mine Methane Reserves

The methane gas reserve associated with the coal mining activities for the proposed project will be evaluated in order to characterize the potential feedstock source. This effort shall include an assessment of 1) existing methane drainage techniques (including gob-well vent systems, if applicable), and opportunities for improving methane drainage effectiveness, 2) coal mine characteristics, 3) area logistics, 4) environmental considerations, and 5) gas ownership implications. All reserve estimates shall be justified on a technical and economic basis. Assessments shall be based on, but not limited to, data/technical information presented in Task 1.

Task 3. Technology Application

The potential of applying the bioprocess to reduce mine methane emissions on both a national and global scale will be evaluated. The detailed assessment of the proposed technology application will include the following: 1) overall approach of coal mining operations and existing degasification systems, 2) efficiency of present degasification systems at the mine site, 3) feasibility and market potential of the bioprocess, 4) probability of success, 5) proposed increase of methane emissions reductions, 6) cost-effectiveness of the proposed bioprocess, and 7) increased efficiency in methane recovery and utilization.

Task 4. Topical Report of Proposed Technology Application

A draft Topical Report of the proposed bioprocess, including an abridged detailed assessment as listed in Task 3, will be submitted to DOE. The draft Topical Report shall include an appendix for use by DOE for preparation of a report to Congress. The draft Topical Report is due 60 days after contract award, with 30 days allowed to DOE to review and approve the draft. The Final Topical Report will be submitted 30 days after DOE review and approval. The report will be submitted to DOE for evaluation and selection of those projects to continue to Phase II. In the event that the DOE does not continue with the Phase II effort, the Final Topical Report for Phase I will be considered the Final Report and shall be provided in publishable form.

Phase II will be a conceptual design for a demonstration of the biological process, aimed at commercializing this resource and substantially reducing methane emissions associated with coal mining. The Phase II tasks will include preparation of a process design and cost estimate, an environmental review, an assessment of market and economic potential and the preparation of a conceptual design and evaluation study. A Phase II project report will be compiled from the results gathered in Phases I and II. Phase III will be a mine-scale demonstration of the technology at a selected JWR site.

PHASE I RESULTS AND DISCUSSION

TASK 1. DETERMINE MINE GAS POTENTIAL

The United States mined 945,424 million tons of coal in 1993. Most of this coal was used for domestic power production with smaller portions used for metallurgy and export. Of this total production, 63 percent came from surface mining operations and 37 percent came from underground coal mines (EIA-DOE, 1994).

The distribution of underground coal production methods can be subdivided into three main categories: continuous, longwall, and conventional (Coal Industry Annual, 1994). Over half of the underground coal production comes from continuous mining methods. In these operations, coal is typically cut and loaded into a waiting shuttle car that then moves the cut coal a short distance to a waiting rail haulage car or to a conveyor belt for transport to the surface. The mining machine must move from the newly cut area to an adjacent face to allow a roof bolting machine to support the roof so that mining may proceed in a safe manner.

Longwall coal production has been increasing in recent years (U.S. Longwall Census, 1994). The total number of long wall mining units has been fairly constant to slightly declining in the last ten years. Recent increases in coal mining productivity are due to the increased coal production from this type of mining. The longwall mining method relies on the continuous mining method to outline a large block of coal (500 to 1100 feet wide by 3000 to 15,000 feet long, U.S. Longwall Census, 1994). The longwall mining machinery then cuts and loads this entire block of coal over a period of 8-18 months. Hydraulic roof supports protect the workers and equipment near the face and the roof is allowed to collapse behind the mining operation forming a longwall gob.

The original conventional mining method is still being used today to mine about 12 percent of the total underground production (Coal Industry Annual, 1994). In using this method, the coal is undercut, holes are drilled into the face and explosives are used to loosen the coal. A loading machine then transfers the coal pile to a shuttle car and subsequently onto rail or conveyor haulage. This mining method requires the least capital cost of the three principle methods, and is the choice of many small mine operators.

Coal is an extremely heterogenous material varying in composition not only from seam to seam but also from location to location within a seam sometimes within a few feet (Vinokurova, 1978). It should not be surprising then to find that the methane gas contents of coals are also quite variable. In the U.S., coal bed gas contents range up to 750 CF/ton of coal (Diamond *et al.*, 1986; Rice, 1991). Generally, gas content increases with depth and with coal rank. Local geologic burial conditions and coal cleat structure (fractures) also influence the amount of gas any specific coal may contain.

Most coal bed methane is physically adsorbed on the coal surface, with a smaller fraction of the gas found as free methane in the fractures of the coal (Vinokurova, 1978). This means that as mining removes the pressure that holds the methane in the coal, only the smaller fraction of trapped gasses are immediately released. The greater quantity of gas must undergo a slower desorption process to be released from the coal. For this reason, storage or shipment of coal must be adequately ventilated. Furthermore, this adsorbed gas adjacent to the mined openings continues to desorb into the mine over long periods of time.

The presence of methane is well documented in the history of coal mining. "Fire damp" was the term early miners used for methane because it made a flame burn very blue and appeared dampened due to the richness of the combustion. Early mines employed a fire boss, whose job it was to burn off accumulated methane gas with a torch every morning before work. A growing number of mine disasters led to the formation of the U.S. Bureau of Mines in 1910, which was dedicated to improving the safety of mining. In pursuit of this mission in recent times, the Bureau of Mines published a large data base on methane emissions from mine fans and has pioneered research to degas coal seams prior to and during mining operations. The mine fan data base has been used extensively as a decision tool for the Climate Action Plan deliberations of which this report is a part. The foundations of the world wide coalbed methane industry, which currently accounts for 5 percent of the total U.S. natural gas production, also derive from early Bureau of Mines work in this area.

Sources of Methane from Mining

Four potential sources of atmospheric methane emissions are associated with coal mining operations:

- methane from mine fan ventilation
- methane from pre-mining drainage wells
- methane from post-mining or gob wells
- methane from abandoned mines

In active mining operations, methane liberation can occur from mine fans, pre-mining drainage wells and post-mining or gob wells. Figure 1 illustrates methane liberation by these three sources.

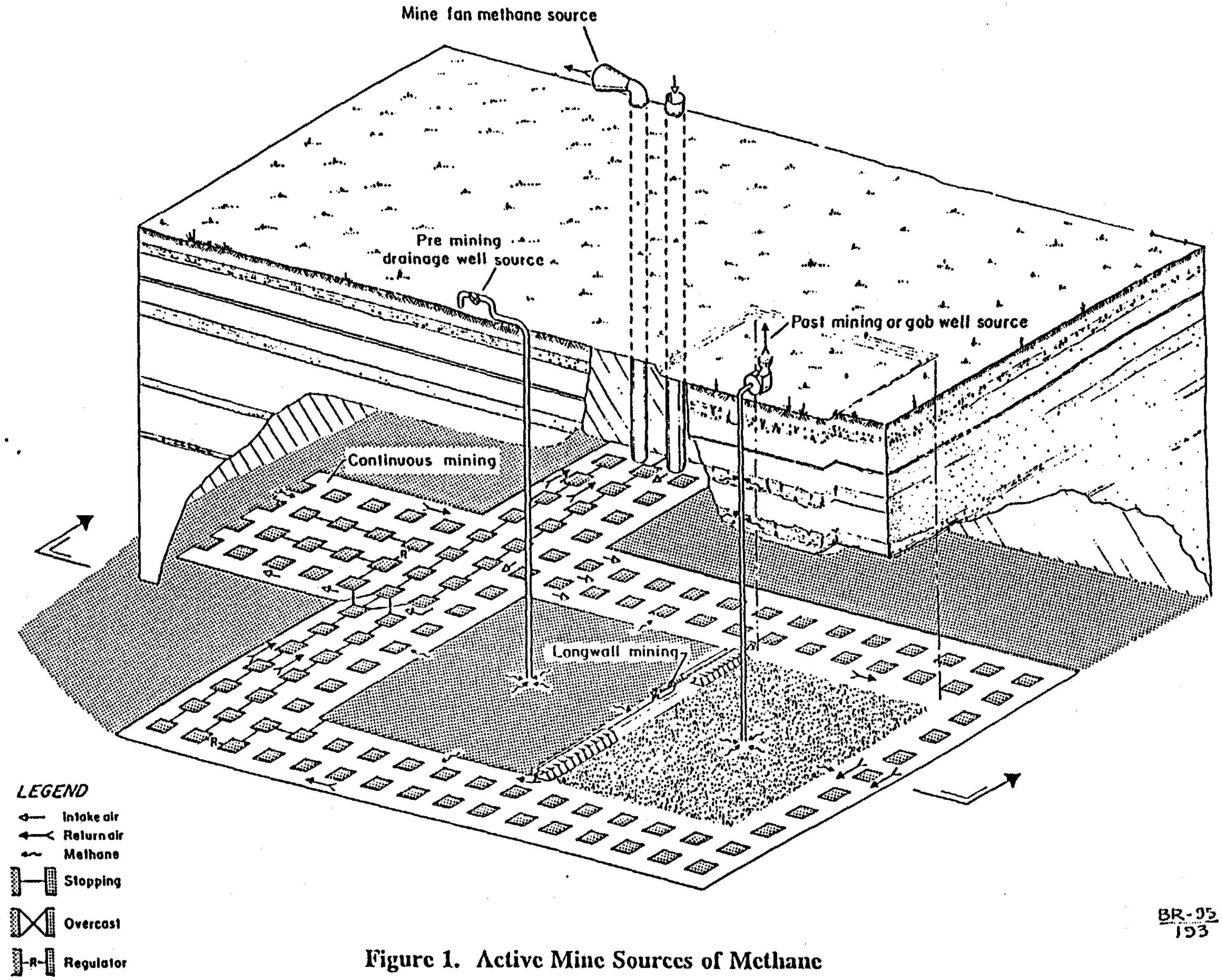

Figure 1. Active Mine Sources of Methane

The largest current source of methane is from the mine fan exhaust that removes gas from all portions of the mine. Vent gas also has the lowest concentration of methane associated with mining operations, typically less than 0.5 percent. Pre-mining wells are stimulated to induce additional flow to the bore hole opening to remove gas prior to mining. This gas contains nearly 100 percent methane, and is readily used for natural gas pipeline sales. Post-mining wells remove methane from the gob, or broken roof coal that remains after the longwall mining process. Not only does gas flow from the coal seam being mined, but overlying coal bearing strata also contribute to the gas production from gob wells. Occasionally the pre-mining and post-mining wells are drilled horizontally from adjacent parts of the mine when surface access is restricted. Methane is then piped to the surface and disposed of in a manner similar to the vertical wells. Because post mining wells are connected to the fresh air supply of the mine, this gas source is often contaminated with air from the mine and consequently has reduced economic value.

The fourth source of atmospheric methane associated with mining is the gas that continues to desorb from the coal after the mine has been abandoned. If an abandoned mine fills with water and the hydrostatic pressure repressurizes the formation, the desorption process stops. However, if the mine does not flood and is sealed, changes in the barometric pressure inevitably cause mine gases to find their way to the surface. The impact of methane emissions from abandoned mines has not been studied extensively. In addition, the control or use of this source of methane is difficult since the rate of methane production from the coal is too slow to warrant significant capital expenditures to develop the resource. Some local use has been made of abandoned coal mine methane resources such as for rural home heating.

The presence of methane presents a significant ignition hazard in underground mining. Removing the methane by any means possible is the greatest concern of the coal miner. The mine engineer has three methods of dealing with methane to reduce the explosion hazard (Logan, 1991):

- Ventilation
- Sealing
- Drainage

Ventilation is used not only to remove methane, but also to provide air for human respiration. In removing methane, ventilation serves two main functions. One function is to dilute the methane from a concentration of near 100 percent found in the coal to less than 40 percent of the lower explosive limit (LEL). This yields a final concentration of less than 2 percent by volume in air. The second function of the ventilation air is to carry the gas out of the mine and to discharge it to the atmosphere. The law requires that a minimum of 9,000 CF of air be provided to each mining section and a minimum of 3,000 CF be provided to each face mining coal (Code of Federal Regulations, 1990). In most mines with any reportable gas content, additional volumes of ventilation air are generally used to enhance safety.

All coal mines use mechanical fans to move ventilation air to the working areas of the mine. These fans range in capacity from about 40,000 to 1.5 million CF per minute. The methane gas content in these fans is required to be less than 20 percent of the LEL, or a final concentration of less than 1 percent by volume in air.

Sealing is done to reduce the quantity of methane found in mined out areas from entering the mines ventilation air supply. Most states now permit portions of active mines to be sealed, thus reducing the amount of ventilation air that must be provided. When an area that is liberating methane is sealed the concentration of methane increases and the volume of oxygen in the abandoned area falls. The mine must then remain closed until it is demonstrated that the gas concentrations behind the seals are non-explosive. Despite the robustness of the seals, small quantities of methane will still leak through or around (through the roof or floor strata) and into the active mining areas due to changing barometric pressures. For this reason, outbye seal areas must be maintained and ventilated to maintain safety.

Drainage of methane before and after mining is the most recent tool used by the coal industry to deal with coalbed gas. Pre-mining gas drainage may be done through vertical or horizontal wells drilled in advance of the mining operations. Depending of the natural fracture system of the coal, these wells may require stimulation to help remove the adsorbed methane gas (Palmer *et al.*, 1993; McElhiney *et al.*, 1991). A typical stimulation would be the high pressure injection of water or gel containing a sand propping agent. When the pressure is relieved, the sand remains behind to prop fractures open and permit the flow of gas.

Post-mining drainage is typically used during longwall mining operations. Unmined coal and coal in roof strata break during the longwall operations because the roof is intentionally caved behind the hydraulic supports. Methane from the roof strata is liberated and travels through the broken rock area, also referred to as the gob, into the mine ventilation system. Wells drilled into the area or converted pre-mining wells can be used to remove this gob gas. As with pre-mining drainage systems these gob holes can be vertical, horizontal from adjacent mined areas, or cross measure, drilled up and over or down and under the gob area from adjacent mined areas.

Every coal mine is required to use mechanical ventilation systems. Other methane drainage methods are used only when mines are very gassy and the ventilation system is unable to remove the methane quickly enough or it becomes too expensive to ventilate the mine.

Mine Gas Potential

Coalbed methane drainage was initially employed as a method to improve the safety of coal mining by removing gas prior to mining of the coal. The surprisingly large volumes of methane produced by these early vertical drainage wells lead to the birth of the current coalbed methane industry which now supplies over 5 percent of the U.S. natural gas supplies. Only a small portion of the coalbed methane supply comes from coal mines or formations where coal is likely to be mined in the near future.

USBM estimates that there are 158 mines with methane emissions exceeding 100,000 CFD. It was reasoned that mines emitting less than this volume would be unlikely locations for degassification wells. Table 3 presents coal bed methane emissions data from 63 of these 158 mines. Data were not available from the balance of the mines. The table shows the mining method (longwall or roof and pillar), whether the mine utilizes pre-mining or post-mining, the well gas volume from both pre-mining and post-mining activities, emsissions from ventilation, coal production from the mine and the ventilation emission per ton. JWR mines are indicated by an asterisk (*) under the mine name.

Of all the data on methane gas emissions from mines, the mine fan data have been most accurately characterized by the Bureau of Mines. While individual mines report to MSHA the methane concentration and gas volumes of fan exhausts, the compilation and analysis of the data has been done on a regular basis by the Bureau of Mines since 1971.

Unlike mine fan emission data where federal law requires records to be maintained for fan volume and methane concentration, mine degassification well data are not well kept or in some cases held as confidential production data. As a result there is a lack of accuracy of the information in these areas. Much of the data relies on a recent EPA report. The methods used by the EPA in the accumulation of this data are not well documented. Other data have been gathered from MSHA, EIA and other sources. Frequent contradictions in the information are found and the true emission rates from mine drainage systems are difficult to confirm and are considered beyond the scope of this report.

Given these limitations, the 1993 MSHA data base was used to generate a list of 158 mines with methane emissions exceeding 100,000 CFD. This data was then cross referenced with the 1994 Longwall Survey to determine the percentage of longwalls exceeding 100,000 CFD. An EPA report was then used to determine the 1990 mine methane gas emissions from the candidate mine fans and degasification systems.

Based on the data compiled in Table 3, it was determined that 54 of the 158 highest gas emitting mines used the longwall method. This accounts for over half of all U.S. longwall mines. Only 24 mines used some form of degasification system and nearly all of the mines using a degasification system used the longwall mining method.

Table 3. Mine Gas Methane Emissions from Gassy Mines

Mine Name	Mining Method	Pre-mining Wells	Post-mining Wells	Well Gas Volume MMCFD	Ventilation Emission MMCFD	Coal Production MM tons	Ventilation Emission CF/ton
Arkwright #1	L		Y	2.1	3.9	1.9	749
Bailey	L		Y	2.6	4.8	5.6	313
Baker	RP			0	0.7	1.2	213
Big Creek Seaboard	RP			0	0.7	0.2	1277
Blacksville #2	L		Y	5.0	9.3	3.8	893
Brushy Creek	RP			0	0.7	1.7	150
Buck Creek				0	3.4	2.0	621
Bullitt	RP			0	0.8	1.1	265
Cambria Slope Mine #3	L		Y	1.8	3.4	2.0	621
Chetopa	RP			0	1.2	0.7	626
Cumberland	L		Y	3.1	5.8	3.0	706
Cyprus Orchard Valley	RP			0	0.6	1.1	199
Deserado	L		Y	0.8	1.5	1.7	322
Dilworth	L			0	1.5	2.4	228
Eagle Nest #2	RP			0	1.2	1.6	274
Eagle Nest #5	RP		Y	0.1	0.2	2.2	33
Emerald #1	L		Y	1.7	3.1	1.6	707
Enlow Fork	L		Y	0.1	0.3	0.3	365
Federal #2	L		Y	5.7	16.2	4.2	1408
Galatia #56-1	L			0	2.7	3.0	329
Gary #50	RP	Y	Y	7.8	7.8	3.4	837
Golden Eagle	L		Y	3.3	9.4	1.5	2287
Grove #1	RP			0	0.6	0.6	365
Humphrey #7	L		Y	3.4	6.3	3.3	697
Ireland	L			0	1.8	2.2	299
Loveridge #22	L		Y	2.7	5.1	2.8	665
Maple Creek	L			0	1.1	2.1	191
Marion	RP			0	0.5	0.9	203
Mary Lee #1	L			0	2.1	1.2	639
McClure #1	L			0	3.8	1.0	1387
McElroy	L			0	1.5	2.7	203
Meigs #2	RP			0	0.9	2.1	156
Meigs #31	RP			0	0.9	2.1	156

#1 Monterey	L**			0	0.6	2.0	110
#1 Bear Ridge	RP			0	0.8	0.2	1460
#1 Maple Meadow	RP			0	3.3	1.3	927
#24 Old Ben	L		Y	0	1.5	1.5	365
#25 Old Ben	L		Y	1.0	1.5	2.7	257
#26 Old Ben	L		Y	1.0	1.8	2.6	253
*#3 Blue Creek	L	Y	Y	8.2	15.2	2.4	2312
#37 Lynch	L			0	0.5	2.7	68
*#4 Blue Creek	L	Y	Y	6.4	11.9	2.5	1737
*#5 Blue Creek	L	Y	Y	10.4	19.4	1.4	5058
*#7 Blue Creek	L	Y	Y	8.9	16.5	2.7	2231
#84 R&P	L	Y	Y	0	3.1	1.3	870
#9 William Sta.				0	1.2	2.4	183
North River #1	L			0	2.0	2.0	365
Oak Grove	L	Y	Y	6.2	11.5	1.8	2332
Orient #6	L			0	0.6	1.5	146
Osage #3	L		Y	2.0	3.8	1.8	771
Pattiki	RP			0	2.1	1.7	451
Pontiki #1	RP			0	0.7	1.6	160
Powhatan #4	L			0	1.4	2.5	204
Rend Lake	L			0	1.2	2.8	156
Robinson Run #95	L		Y	1.1	2.1	1.9	403
Sentinel	RP			0	1.2	1.0	438
Showmaker	L			0	2.2	3.1	259
Southfield	RP			0	0.6	0.3	730
Sunnyside Mine #1	RP			0	1.7	0.7	886
Urling #1	RP			0	1.1	1.0	402
VP #1	RP	Y	Y	7.5	9.5	1.9	1825
Wabash	RP			0	2.7	3.2	308
Wheatcroft	L		Y	0.3	0.6	2.7	81

Data from *Longwall Census* (1994), Kruger (1994) and Coal Industry Annual (1993).
* - JWR mine
L - longwall
RP - roof and pillar
** - indicated as longwall by one reference, and roof and pillar by another reference

1. Methane Produced as Ventilation Gas

United States. In the United States, ventilation gas typically contains less than 0.5 percent methane in air. By law, the concentration must be below 1 percent with state laws sometimes more rigorous. The volume of these gases is enormous, with many mines emitting >1000 MCFD. Mines liberating <100 MCFD represent only 2 percent of the total U.S. methane liberation in ventilation gas. The top 25 mines all liberate over 3000 MCFD methane. The total methane emissions from all U.S. mines is approximately 300 MMCFD and the worldwide emissions are estimated to be about 1 BCFD.

JWR. JWR has four mines, each liberating 15 MMCF/day methane in ventilation gas, for a total of approximately 60 MMCFD. These emissions are from mines in the extremely gassy Mary Lee coal bed, and represent four of the top five mines in terms of total emissions per day.

2. Methane Produced from Gobs

United States. Gob wells are used to vent the build up of methane in shut in areas of coal mines. At most mines this gas is vented to the atmosphere. Typical concentrations of gob gas are 20-80 percent methane. Since this is usually not pipeline quality and it is not flared, it is vented to the atmosphere. When mining operations cease, existing gob wells are shut in and further potential production is terminated. It is estimated that gobs produce 38 MMCFD in the U.S. (Table 3). Gob wells are not commonly used in other countries and therefore will not significantly contribute to global methane emissions.

JWR. Because JWR has in place an active emission program, very little gob gas is vented to the atmosphere. In fact, the JWR gob gas contains 96-98 percent methane. As much as 75-80 percent of JWR's total methane production is from gob wells.

3. Methane Produced from Premining Wells

United States. The data for this gas production is very spotty and varies widely from state to state. Table 4 shows current numbers for gas production from coal beds. In some cases it is impossible to separate simple coal bed methane production from gas production at coal mines. In some states, detailed numbers are available, while in others, reporting is not required, and therefore the exact numbers are not known.

Table 4. Coal Mine/Bed Methane Production by State

State	Year	# of Wells	Estimated Reserves, BCF	Production, MMCFY
Alabama	unknown	unknown		unknown
Alaska	unknown	unknown		unknown
Arkansas	1995	none		none
Colorado	1992	624		79
Illinois	1995	unknown	9000	unknown
Indiana	1995	none	unknown	none
Iowa	1995	none	unknown	none
Kansas	1995	none	unknown	none
Kentucky	1995	(few)	unknown	small
Missouri	1995	none	unknown	none
Montana	1995	not reported	unknown	not reported separately
Nebraska	1995	none	none	none
New Mexico	1995	1900	48000	438000
Ohio	1995	none	unknown	none
Oklahoma	1995	none	unknown	none
Pennsylvania	1995	72	unknown	2800
Tennessee	1995	none	unknown	none
Utah	1995	>75	unknown	5480
Virginia	1994	unknown	unknown	29000
Washington	1995	none	28000	none
West Virginia	1995	unknown	unknown	unknown
Wyoming	1994	11	5430	76000

JWR. Alabama wells are permitted by type - coalbed fracwell, gobwell, ventwell - for horizontal drilling underground. In 1995 JWR is producing 36-39 MMCFD from all sources and salting directly. This is about 12 BCF/yr over the last 12 months.

The JWR complex of mines in Alabama are among the highest methane gas producing mines in the United States. This situation creates unique opportunities in the research and development of new technologies such as the production of methane from coalbeds as natural gas. Another similar opportunity may be realized with the development of a new technology to use the dilute waste gas streams of methane that are currently vented to the atmosphere.

JWR currently operates four mines that together in 1990 produced 63 MMCFD of methane in the mine fan exhausts at concentrations near 0.5 percent. Daily methane production from both vertical gob wells and horizontal degas wells produced on average 30.4 MMCFD of pipeline quality methane gas. Using the following calculation:

$$\frac{\text{Production}_{\text{wells}}}{\text{Emission}_{\text{fan}} + \text{Production}_{\text{wells}}} \times 100 = 33\% \qquad (1)$$

one third of the total gas associated with the mining operations is captured and sold as pipe line quality natural gas. While efforts are made to improve this quantity of pipeline gas, significant amounts will still be present as dilute gas in the fan exhaust in order to safely mine the coal.

Methane Emissions from Abandoned Mines

An often overlooked source of anthropogenic atmospheric methane emissions comes from abandoned mines. Because miners and equipment must be safely removed at the end of mining operations, about 40 percent of the coal seam remains to provide roof support. Given an underground mine production of 351 MM tons, an additional 234 MM tons of coal remains underground. Had this coal been produced, the methane content might be similar to that of the U.S. average of 280 CF/ton (Table 3). If all of this methane were to desorb to the atmosphere, an additional 184 MMCF would be added to mine emissions each year. However, factors such as flooding of abandoned mines, slow rates of desorption, bacterial consumption of methane as it migrates through surface soils, and other factors may significantly reduce this quantity.

Methane emissions from abandoned mines are the most poorly documented in the literature. The following calculations are offered more to begin discussions of the area rather than to serve as any definitive treatment. The Energy Information Agency data indicated that for 1993, U. S. underground coal mines produced 351 MM tons of coal. At a generous recovery ratio of 60 percent, the unrecovered coal abandoned after mining can be calculated as:

$$\frac{\text{pct. unrecovered}}{\text{recovered tons * pct recovered}} = \text{unrecovered tons} \qquad (2)$$

This gives a total of 234 MM tons of coal left in place after each year of mining. In general the volume of coal mined underground has been fairly constant, with the increase in national coal production being attributable to increases in surface mining. Clearly the last 50 years of mining have left tremendous quantities of coal in abandoned mines.

The total volume of methane contained in this coal is also difficult to estimate. It is known, however, that on average from 1971 through 1988, 284 CF of methane per ton of coal mined were liberated into the atmosphere (Table 5). Similar quantities of methane may be expected to continue to enter the mine works from the original seam and from adjacent seams that are now under reduced pressure because of the abandoned mine openings. The total potential volume of methane remaining associated with the mining operations and surrounding depressurized areas could be expressed as:

unrecovered tons * average cubic feet per ton = cubic feet (3)

or 0.66 TCF. This potential is generated each year. If similar quantities of methane have been generated over the last 50 years, this total potential volume becomes 33 TCF.

Many factors prevent this potential pool of methane from reaching the atmosphere. For example, many mines with significant methane are below the water table and fill with water after mining, thereby stopping desorption of gas from the coal or surroundings. The characteristics of the desorption isotherm and flow of released methane to the abandoned mine opening slows the potential release of gas from this source. A complete analysis of this source is beyond the scope of this current work statement. Nevertheless, if only 0.1 percent of the potential volume of methane available reaches the atmosphere, this source would be contributing 90 MMCFD to the atmosphere (33×10^{12} * $0.1\% / 365 = 90 \times 10^{6}$).

Significance. At least 300 MMCFD of vent gas is emitted from coal mines in the United States and approximately 1 BCFD is emitted worldwide. Gob gas emissions are difficult to estimate, although U.S. projections are about 38 MMCFD. Methane emissions from abandoned mines may be as much as 90 MMCFD. These emissions represent a significant pollution burden which could also be used as a feedstock in the biological production of methanol and SCP.

TASK 2. EVALUATE COAL MINE METHANE RESERVES

Emission Trends

Mine methane emissions have been generally increasing over the last 22 years. Table 5 shows the historic trends of mine methane emissions, number of mines, underground mine production and total number of underground mines. While there is some variability in the data, the trends indicated provide useful insight into the potential of this mine methane resource.

The data of Table 5 shows that the total number of underground mines is about one half that of 1971, while the number of significant methane emitting mines has remained nearly constant (Grau, 1988; Grau and LaScola, 1984; Irani *et al.*, 1972, 1974, 1977). This can be attributed to the decline in the number of small mines, that never contributed in any substantial manner to the total mine methane emissions.

During this same period of time, the underground mine tonnage has also generally grown, up 27 percent from 1971. It is also remarkable to note that this increase in tonnage came from only half the number of mines operating in 1971. This reflects both increased productivity of both continuous and longwall mining machinery, and the trend toward more large mine complexes and fewer small mines.

The final analysis of the changing mine characteristics can be seen in the last column of Table 5. There is an increasing percentage of mines with emissions greater than 100,000 CFD. Technology which is designed to utilize mine fan methane emissions has a corresponding increasing percentage of sites for application, and thereby decrease overall coal mine methane emissions.

Table 5. Trends in U.S. Coalbed Methane Emissions

Year	# of Mines >.1 MMCFD	MMCFD	MMCFD/Mine Average	MM tons	CF/ton Average	Number UG Mines	% Mines >.1MMCFD
1971	199	227	1.14	276	300	2268	8.8
1973	192	214	1.11	299	261	1737	11.1
1975	196	216	1.10	293	269	2212	8.9
1980	199	256	1.29	337	277	1887	10.5
1985	180	304	1.69	350	317	1695	10.6
1988	193	290	1.51	382	279	1463	13.2
1993	160			351		1196	13.4

JWR Emission Trends

JWR collects monthly data on their fan operations and methane flows through the fan. Their procedures involve measuring the volume of air and the gas concentrations in four underground passages leading to the bottom of the fan shaft. The number of cubic feet of methane in each passage is calculated and recorded in monthly reports submitted to the State of Alabama. Table 6 shows this data tabulated by averaging the four fan approach data sets from Mine No. 5. The No. 5 mine has two exhaust air shafts and is the most likely site for construction of an SCP manufacturing facility. Methane concentrations at the fan shafts vary between 0.39 and 0.62 percent methane, averaging 0.51 and 0.52 percent at the individual fan shafts. Virtually all of the fan methane would be available for SCP production provided an appropriately sized manufacturing facility is constructed.

Figure 2 shows that the total volume of methane emitted from No. 5 Mine on a monthly basis was fairly consistent. Over the longer term, Table 6 shows that the yearly mine fan methane emissions have also remained consistent. Mine personnel predict that coal reserves will enable mining to continue for at least the next 10 years.

Table 6. No. 5 Mine History of Methane Fan Emissions at JWR

Year	Methane, MMCF/day
1985	17.1
1988	15.5
1990	19.4
1995	14.2

JWR does not separate well methane production by mine, and therefore, determination of degasification efficiency by mine is not possible. The data in Table 7 show the historical production trends on a company wide basis for gob well (pre and post mining) and horizontal degasification on a

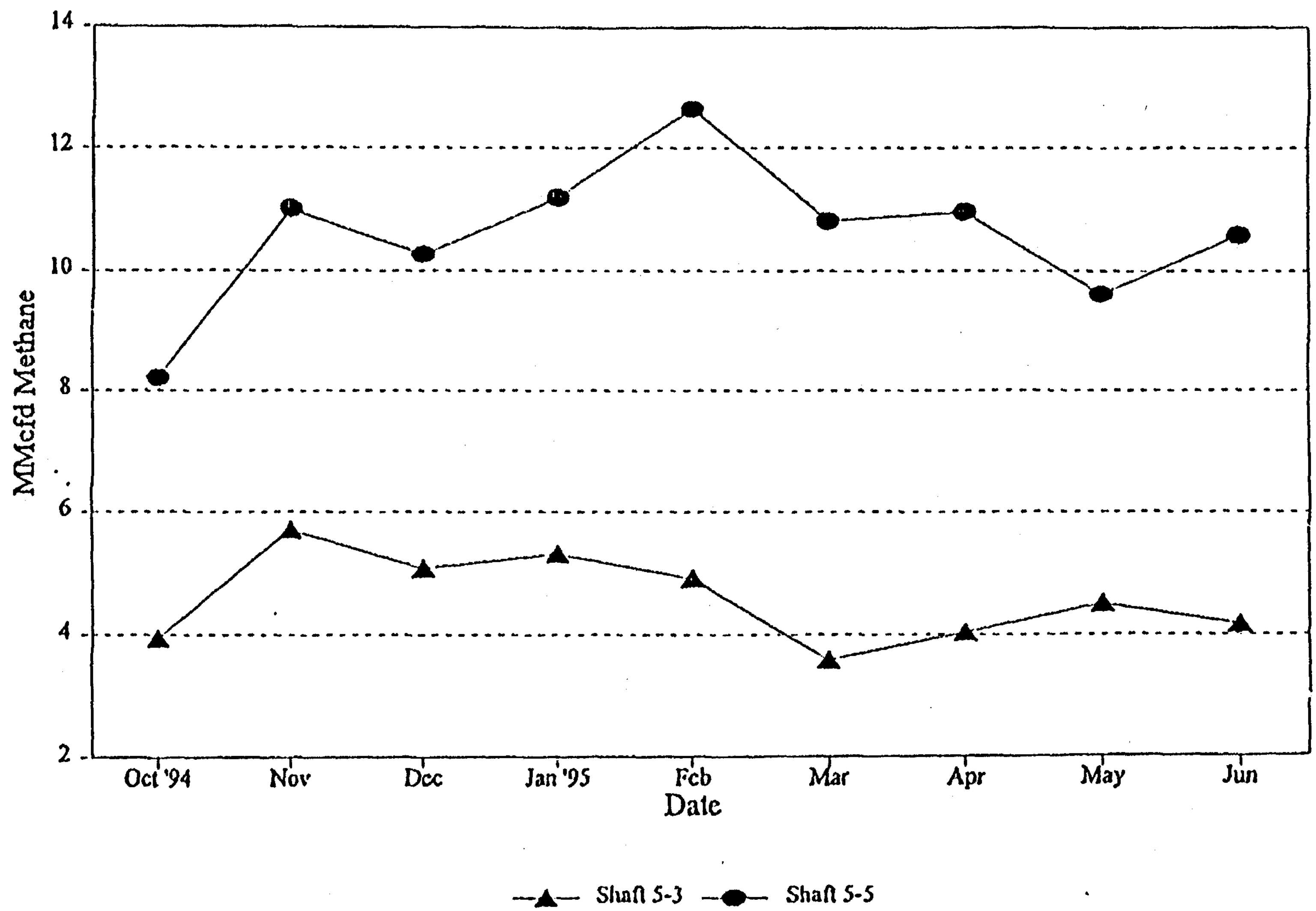

Figure 2. Monthly Methane Production from No. 5 Mine Exhaust Shafts

monthly basis. Gob well production has declined from 29.2 MMCFD in 1989 to 23.4 MMCFD in 1994. Horizontal production has declined by about 31 percent during the same time period.

The quality of JWR gob gas is unusually high, allowing the company to sell the gas as pipeline quality natural gas. Nearly all of JWR's gob gas is sold to the pipeline company. Company officials indicate that, on occasion, low quality gob gas may occasionally be vented to the atmosphere in order to insure safe levels of methane underground. These amounts are trivial and counter productive to the companies gas sales goals, and therefore, a strong economic incentive exists to minimize atmospheric release of methane.

Obviously sufficient quantities of gob well gas are present to augment the SCP production if the demand warrants such use of the methane. In fact, our estimates show that SCP increases the value of methane by a factor of about ten. This analysis may argue for supplementing the ventilation gas stream with gob gas at the SCP manufacturing facility as a way to increase production with minimal additional capital cost.

Table 7. Gas Well Production Records for the JWR Complex of Mines

Year	Gob Well Production MMCF/day	Horizontal Production MMCF/day
1989	29206	4078
1990	29823	3638
1991	24648	3273
1992	24098	3499
1993	22675	2993
1994	23380	2798

Application of SCP Process to Mine Sources

The most important application of the biological process to convert methane gas to SCP is in the mine fan exhaust since this represents a tremendous resource that is not readily used by any other technology. However, the SCP process is not limited to this application. Higher concentration gas streams can also be utilized. There may be applications where access to pipelines from pre-mining wells is too expensive, or where a post mining well gas concentration is too low to upgrade to pipeline quality or other use. Another potential application is to abandoned mining situations where an SCP plant was already in operation at the mine and after mining has been completed, the remaining lower volume gas production from the mine might be used to continue profitable operation, especially considering the increased value of the SCP versus methane. The ability to continue an industrial operation beyond the normal mine life not only continues employment in the area, it also helps to use methane that otherwise would escape into the environment. Finally, the SCP process can be used in conjunction with other technologies for mine gas utilization.

The concept of SCP production from dilute fan gas streams is unique. With the exception of using small fractions of the mine fan exhaust air as combustion air for boilers or engines, there are no other economical alternatives for using the methane from this source. Membrane, cryogenic, or other concentrating technologies all require excessive energy to be viable. Once diluted, entropy prevents methane from self separating and energy must be expended to separate the gas.

A bioprocess accomplishes this separation through the natural kinetics of cell metabolism and growth. BRI laboratory data clearly show that cell growth occurs at a concentration of 2 percent methane (see Task 3 information). At an eight fold reduction to 0.25 percent, some decline in growth is expected, but the process should still be economical. A significant question for the long term potential of this project may be what is the lowest methane concentration at which the process will still be economical.

The bioreactor for SCP production from dilute methane streams may be either above ground or incorporated into the mine infrastructure. Of these two alternatives, above ground operation is likely to be more feasible due to the presence of coal and rock dust in the ventilation air and the inherent difficulties associated with operating a process underground. Underground operations, however, are likely to be more economical. The Phase III demonstration will thus concentrate on an above ground process; underground operation will be investigated as a potential concept in Phase II.

<u>Above Ground Bioreactors</u>. Above ground bioreactors for SCP production from either dilute or intermediate methane streams include the spray column, the continuous stirred tank reactor (CSTR) and the trickle bed reactor. The spray column is probably more appropriate for vent gas streams, and the trickle bed and CSTR are more appropriate for intermediate or gob gas streams. Figure 3 illustrates the use of a spray column for SCP production from vent gas. The gas from the mine fan exhaust is sent to a temporary metal building which serves as the bioreactor. Inside the building, liquid medium containing the necessary nutrients and cells in a fine mist or spray are contacted with the gas, thereby providing the necessary gas-liquid mass transfer prior to reaction. The conversion of methane and oxygen to SCP takes place in the liquid droplets. The liquid containing SCP is collected in a drainage network, where the separation of SCP from the medium takes place. The separated SCP is dried to produce the final product and the medium is recycled. The exhaust gas is used as return air at a significantly reduced methane concentration.

Figures 4 and 5 show CSTR and trickle bed reactor options for treating intermediate or gob gas in an above ground operation. The trickle bed reactor provides gas-liquid mass transfer by rapidly recirculating liquid medium and cells through a packed column. SCP formation occurs as the liquid travels the length of the column. A stirred tank reactor provides gas-liquid mass transfer by agitating the liquid as the gas is sparged into the reactor. SCP formation then occurs inside the liquid phase of the reactor vessel. In both cases, a hollow fiber filler is used to concentrate cells. SCP is centrifuged from the medium and then dried to produce the final product.

<u>Underground Bioreactors</u>. It may also be quite feasible to incorporate a bioreactor into the mine infrastructure. Although the approach has technical problems, it reduces the capital costs of separate surface structures to produce SCP. In this concept, the return airways of a mine would be cleaned, shotcreted with cement, and appropriate drains and sumps would be constructed. Homotopal spray bars would be appropriately sized to maximize the contact of nutrient and microbially laden solution with the mine ventilation air. The velocity of the mine air and reaction rates of the organisms would be used to determine the length of return airway that would be required.

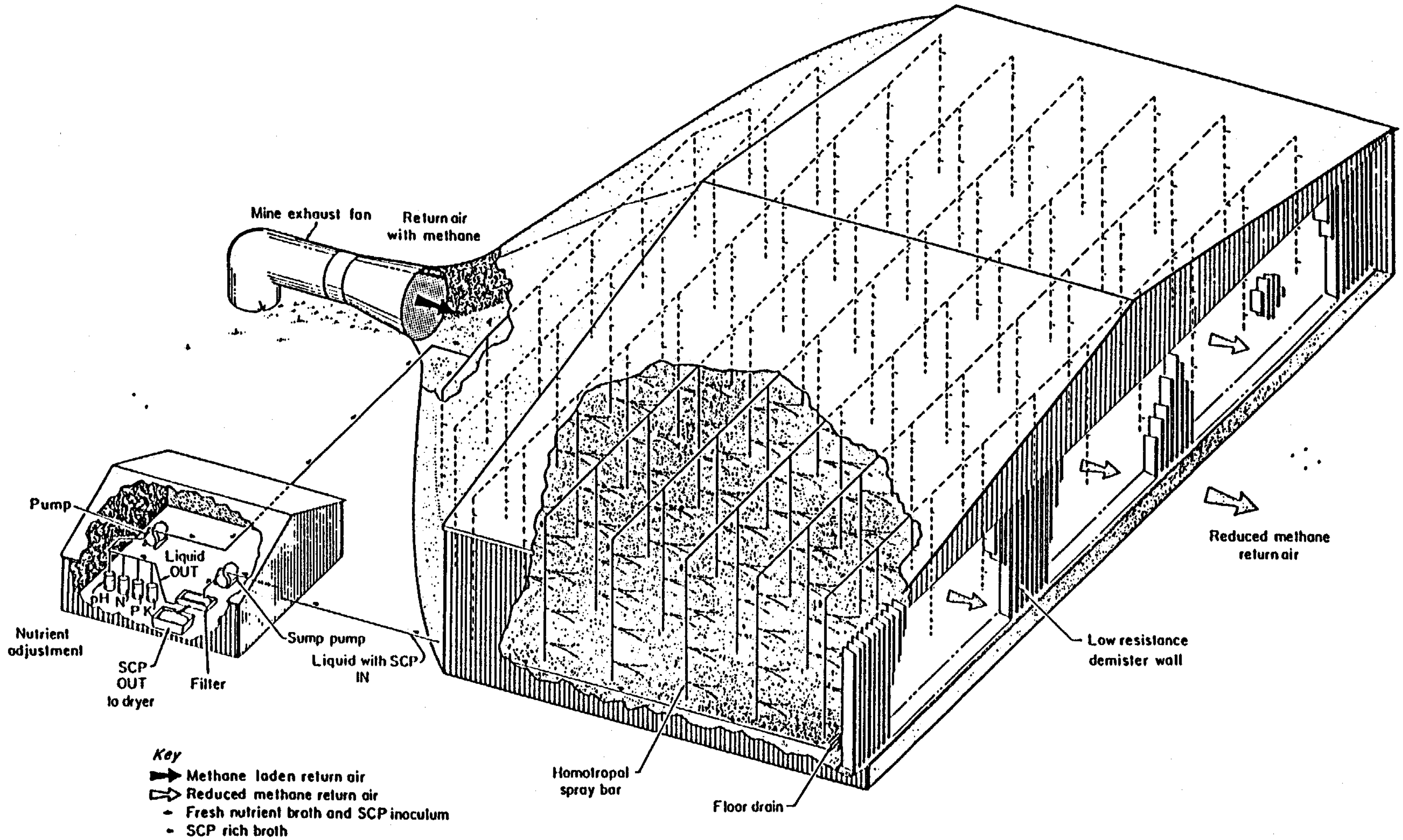

Figure 3. Above Ground Vent Gas Bioreactor

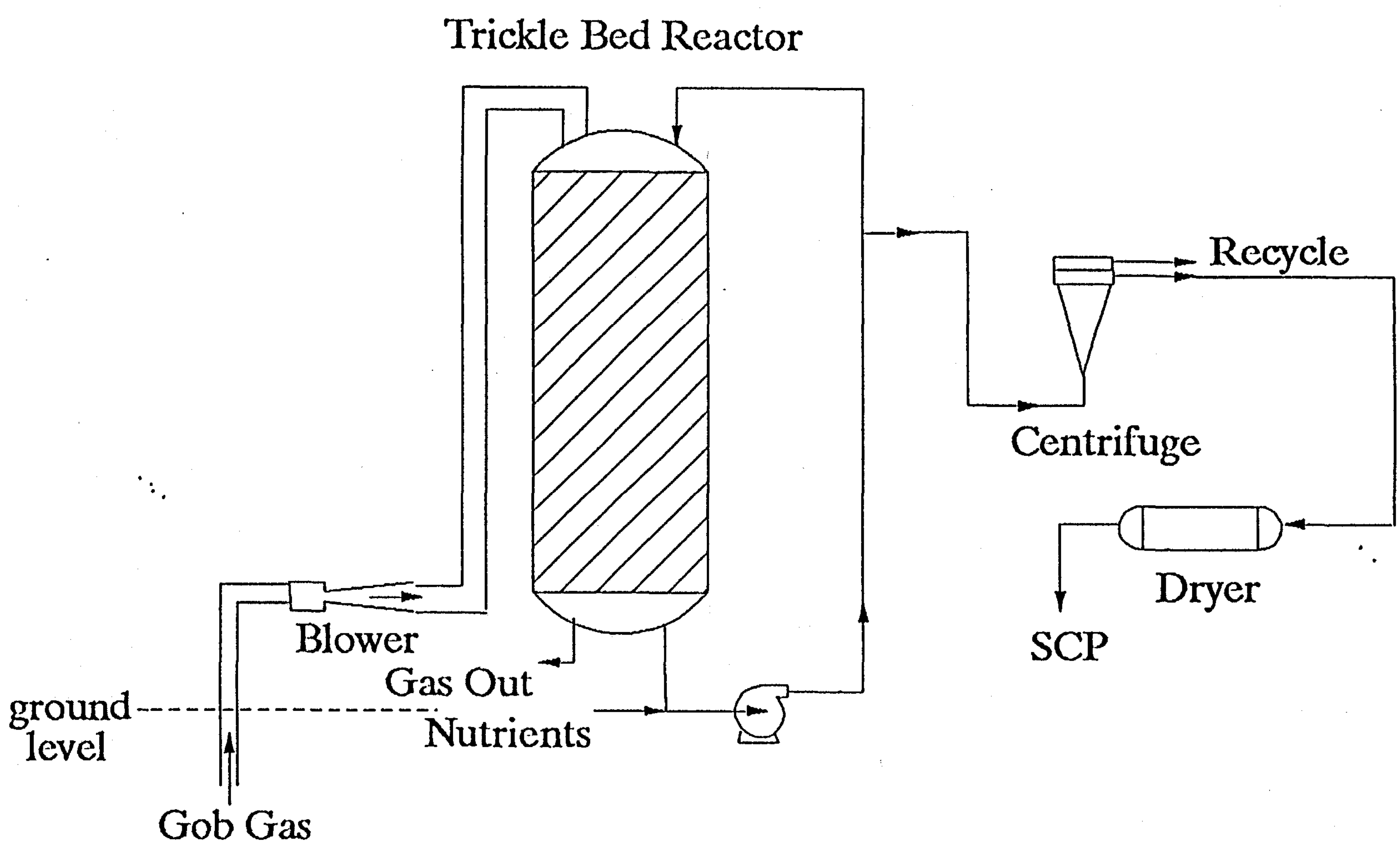

Figure 4. Above Ground Trickle Bed Reactor for Gob Gas Conversion

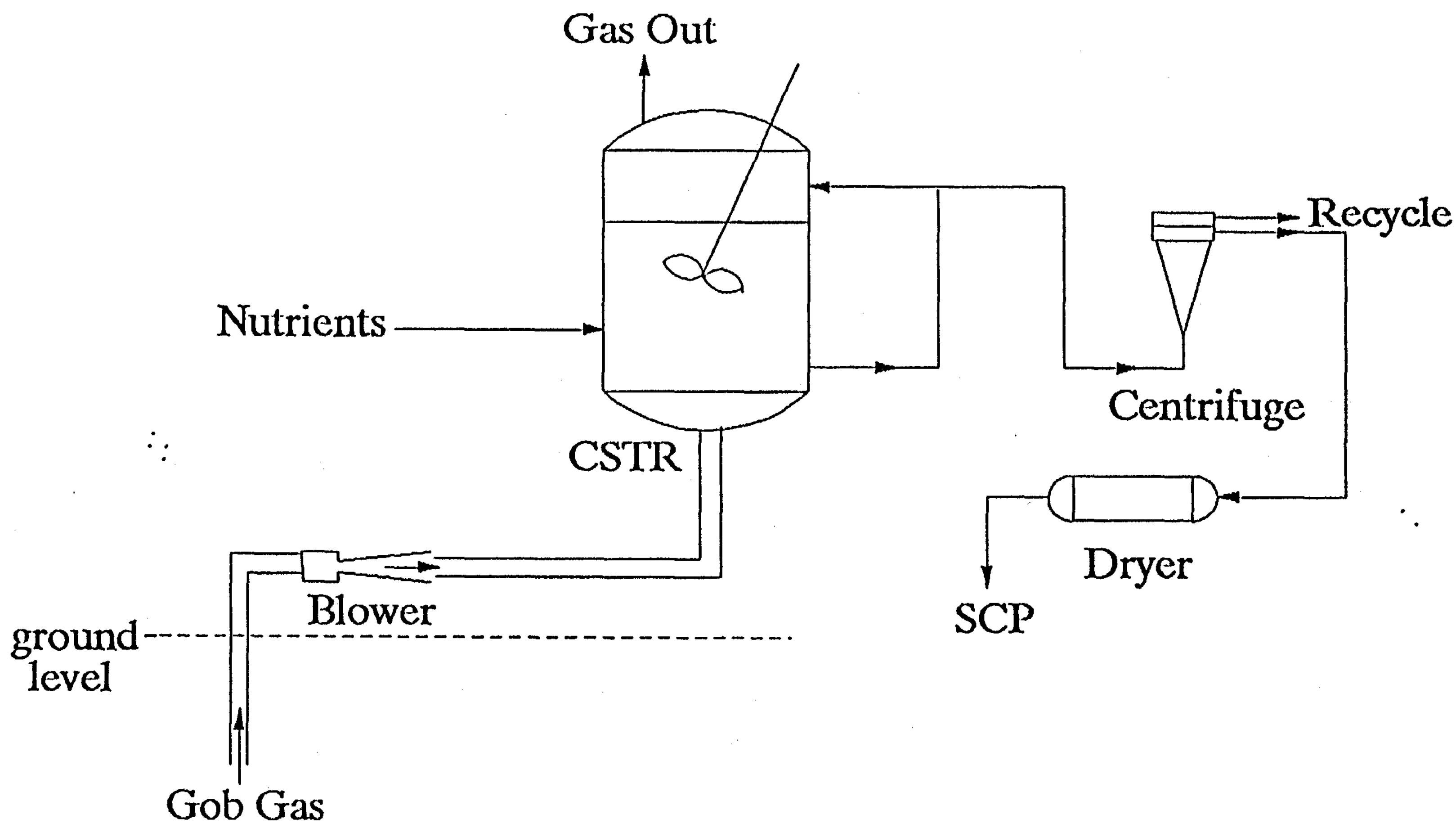

Figure 5. Above Ground Stirred Tank Reactor for Gob Gas Conversion

Figure 6 shows a detail of the reactor where a pump is used to spray a mixture of water, nutrients, and SCP inoculum into the return air stream where methane gas is taken from the air by the microorganisms as their carbon source for growth. The droplets fall by gravity to the floor drains where they are carried to a sump. A mist eliminator may be used after the final spray bar to finish theremoval of liquid prior to the return air entering the exhaust shaft. A second pump then drains the sump and takes the liquid mixture to a filter where a portion of the SCP is removed and the mixture is checked for accumulation of wastes and adjusted with nutrients for reuse.

From a mining perspective, cleaning and shotcreting the return airways improves the efficiency of the mine ventilation system. Orientation of the sprays in the same direction as the airflow further improves the air movement through the return. These improvements should balance any increased resistance caused by the demister used to remove droplets from the air stream prior to reaching the higher velocities of the return air shaft. While this type of bioreactor may not be as efficient as other types, an economic evaluation of this approach seems warranted in future phases of this work.

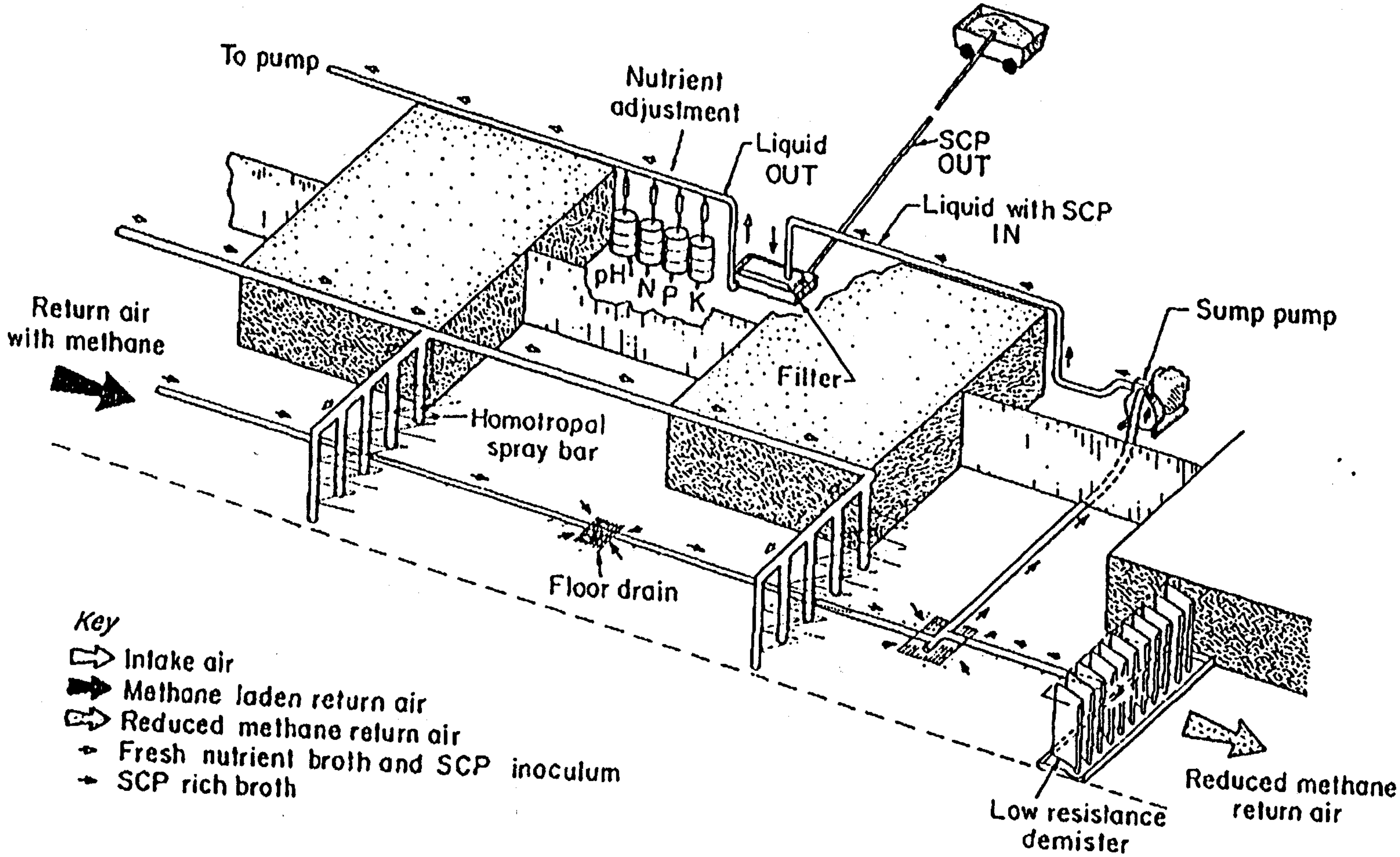

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Figure 6. Detail of Inmine Bioreactor

SCP Production Potential

Ventilation gas, because of its low methane concentration of only 0.2-0.6 percent, cannot be easily recovered and utilized for power generation. The total methane ventilation emissions from all U.S. mines is approximately 300 MMCFD and the worldwide emissions are estimated to be about 1 BCFD. Converting all the U.S. emissions into SCP would yield about 1.4 MM tons of SCP per year. However, for logistical reasons and reasons of economics, not all of this gas will be available for conversion to SCP. In addition, it may not be possible to use all of the methane from a 0.5 percent gas stream. If only 10 percent of the vent gas can be utilized, 140,000 tons of SCP could be produced from this gas ventilation stream on an annual basis.

JWR has four mines liberating a total of approximately 60 MMCFD of vent gas. Conversion of this gas to SCP would yield about 280,000 tons/yr of product. If 10 percent of this gas could be utilized, 28,000 tons/yr of SCP would be produced. If the market can bear additional SCP production, the vent gas could be supplemented with low quality gob gas to generate additional SCP.

Markets for SCP

SCP has a very large market as an animal feed as a substitute for soya meal, fish meal, etc. in animal or poultry diets (Sharp, 1990). The potential market for SCP is large and the price is high. The current world production of all protein products is about 200 million tons annually. Prices are approximately $500 per ton of protein, which would give a price of $375 per ton of SCP (biomass). This price translates into a value of $8.33 per MSCF methane, far more than current natural gas prices. Even with SCP at $220/ton (the current soybean price) a coal mine producing 15 million SCFD of methane (typical of a JWR mine) could generate an additional $17 million annually in revenue from the vented methane. If methanol is desired, the process would be stopped at the intermediate methanol prior to conversion to cell mass. Methanol would then be recovered by extraction and distillation.

Although the concept of producing SCP and methanol from coal mine methane is unique, the production of SCP from hydrocarbons is commercial technology. As world protein shortages were perceived in the late 1960's, significant research efforts were initiated to investigate microbial protein production from mineral and hydrocarbon sources, both in the U.S. and Europe (Sharp, 1990). Fungal, algal and bacterial processes were developed. The protein quality for various microbial proteins was demonstrated for animal and human consumption (Goldberg, 1985a; Moo-Young and Gregory, 1986). The substrates for these processes included CO_2, alcohols, n-paraffins, molasses, sulfite wastes, etc. These processes were all deemed technical successes, but some were economic failures, primarily because of the sharp increases in petroleum prices in the late 1970's and early 1980's. No plants were built utilizing methane as the substrate, although the microbiology was investigated.

The use of coal mine methane to produce methanol and SCP will utilize more dilute concentrations than have been previously investigated. BRI has demonstrated that the proprietary strain F1L is capable of converting a wide range of methane concentrations, including 1-2 percent methane in ventilation air and highly concentrated methane from gob wells. By using a hollow fiber membrane for effluent withdrawal, cell (SCP) concentrations as high as 30 g/L have been achieved. Gas retention time, which controls reactor volume, has been reduced to as low as 30 sec by utilizing reactors with high mass transfer coefficients. Based upon these preliminary data, the capital investment for producing SCP from a large coal mine discharging 15 million SCFD methane would be about \$13 million. The payout for the process based on SCP sales would be 2.1 yrs (see Table 13). Therefore, there is significant economic potential for developing this technology.

Tyson Foods has expressed interest in SCP production from this process as a poultry feed supplement. A letter of support of is attached.

Energy Savings

An additional benefit to utilizing coal mine methane to produce SCP is the energy savings over soybean production technology, the traditional source of protein in the U.S. It is estimated that the production of SCP will save more than 5 million BTU/ton SCP•yr over soybean production. Thus, for a plant producing 60,000 tons SCP/yr (a typical facility from a single JWR mine), the energy savings is 0.32 trillion BTU/yr.

Tyson Foods, Inc. 2210 Oaklawn Drive • P.O. Box 2020 • Springdale, AR 72762-6999 • 1-800-643-3410

August 11, 1995

Dr. J. L. Gaddy
President
Bioengineering Resources, Inc.
1650 Emmaus Road
Fayetteville, AR 72701

Dear Jim,

We have reviewed your DOE project entitled Utilization of Coal Mine Methane for SCP Production. We believe that this project has the potential for producing low cost protein that can be used as a poultry feed supplement.

Accordingly, we would like to participate in this project. Tyson Foods is the largest poultry producer in the world. We feed approximately 30 million chickens per week. Feed quality and cost is a very important part of our business and we are constantly seeking new ways to improve this operation.

We would like to be involved in the Phase II project by reviewing your laboratory data and reports and providing advice on applications in the poultry industry. During your Phase III demonstration at Jim Walters coal mines, you will be able to produce sufficient quantities of protein for marketing studies. Tyson would participate in these feeding trials to determine the potential quantities of SCP that can be supplemented in poultry diets. Tyson Foods reserves the right to discontinue our participation at any time should the project fail to meet our technical or economic criteria.

We look forward to working with you on this exciting project.

Sincerely,

Ellis W. Brunton

Ellis W. Brunton, Ph.D.
V.P. Research & Quality Assurance

Factors Affecting Coal Mine Methane Utilization

From an economical point of view, the amounts of methane which can be readily accumulated through mining operations may be significant (Kruger 1994, 1994a). Several factors impact these numbers and the potential for economic production of the gas.

The first is the nature of the coal itself. From U.S. Bureau of Mines data it is clear that the amount of gas found in coal is dependent upon several factors. The depth of the coal seam plays a significant role. If the seam is relatively shallow, the amount of gas in the coal is minimal, and presumably the gas, if it was ever present, has desorbed and seeped to the surface and atmosphere over the long periods of geological time since coal formation. The lower atmospheric pressure of shallow coals also plays a role in this desorption. The rank of the coal also plays a significant role in the amount of gas in the coal. Generally speaking, the higher rank of the coal the more gas it contains. However, some coals of equal rank are significantly different in gas content. The coals of the Black Warrior basin in Alabama are among the gassiest, and gas emissions of up to 400 CF/ton may sometimes be measured. The age of the mine appears to have little effect on the amount of gas produced during the mining operations.

A second factor is the price of natural gas (Schraunagel, 1991; Kuuskraa, 1991). In Alabama, the River Gas Co. produces large amounts of methane from coal beds in southern Alabama, and because of a Federal subsidy, makes a significant profit. However, River Gas operations in Utah do not benefit from this subsidy and the current price of natural gas makes these operations barely profitable. From these River Gas Co. experiences, it is obvious that coal bed methane production is not a highly lucrative business in an open and free market. However, coal mine methane can be seen as a simple additional product from the production of coal. JWR produces significant pipeline grade methane from its operations in Alabama and benefits from the required removal of methane from its mines to recapture some of their costs from methane production. This system is monetarily valuable for the company.

The third factor is totally non-technical and involves ownership issues. These issues vary greatly from state to state. However, the situation can be simplified into two major observations. First, the major ownership questions occur in the East. These are affected by the states defining mineral and coal ownership rights differently and the fact the actual leases are sometime written in such a way that the issue is ambiguous. Not only are mineral and oil and gas ownership rights often split, but sometimes there are even splits in different mineral rights. Since it is impossible to determine who owns what without legal action, the production of methane from coal mines or coal beds has not been active in many eastern states. There are exceptions, Alabama, Virginia and West Virginia produce significant quantities of coal mine and coal bed methane. In these three states the ownership issues have either been resolved or a mechanism is in place for resolution, therefore not impeding gas production. In the West, these issues are usually moot. The oil and gas owner typically owns rights to the coal bed gas. In the West, most of the underground mines are not gassy and many of the largest mines are surface mines. Therefore the coal-related gas that is produced comes almost entirely from deep coal beds and is produced by oil and gas companies.

The Federal Energy Policy Act of 1992 requires the U.S. Department of the Interior (DOI) to regulate coal bed methane development in "affected states" and specifically finds ten states exempt: Alabama, Colorado, Louisiana, Mississippi, Montana, New Mexico, Wyoming, Utah, Virginia and Washington (Mockler, 1994; Rocky Mountain Region Reports, USPS-130-170, USPS-130-115, USPS-130-109, Staley, 1994).. The "affected states" are: Illinois, Indiana, Kentucky, Ohio, Pennsylvania, Tennessee and West Virginia (Harper, 1991). Outside comments were received recommending that Alaska, Arkansas, Maryland, Oklahoma and Texas be added to the "affected states" list, but DOI did not have sufficient information to make a determination on those states. The act directs the DOI to apply the law to all lands within the "affected states". These states have until October 1995 to develop their own coal bed methane regulations and therefore avoid federal regulation. The DOI is poised to apply regulations closely resembling the 1990 Virginia Gas and Oil Act (attached as Appendix B). As of the date of this report, only one of the "affected states" has promulgated their own regulations. In addition to the pioneering law of Virginia, West Virginia has also passed regulations in March 1994 similar to the 1990 Virginia Gas and Oil Act (Virginia Department of Mines, Minerals and Energy, 1990).. The "affected states" are currently in the process of deciding what their regulations will be (Hansen, 1994). A summary is presented in Table 8. Additional notes on ownership follow Table 8.

Table 8. Ownership of Coal Mine/Bed Methane in Potential Producing States

State	Status	Action/Owner	Comments
Virginia	Exempt	1990 Gas&Oil Act	Used as Federal Model
Illinois	Affected	Coal Owner	note 3
Indiana	Affected	Undecided	note 2
Kentucky	Affected	Pennsylvania model/Undecided	note 1
Ohio	Affected	Undecided	note 2
Pennsylvania	Affected	Remove from affected status/Undecided	note 4
Tennessee	Affected	DOI rules will apply/Undecided	note 5
West Virginia	Affected	1994 Act	based on Virginia
Alabama	Exempt	Coal Owner	
Alaska	Not affected	Undecided	
Arkansas	Not affected	Regulated by the State Oil & Gas Commission	note 6
Colorado	Exempt	Oil & Gas Operator	Indian tribe
Iowa	Not affected	Undecided	note 6
Kansas	Not affected	Undecided	note 6
Missouri	Not affected	Undecided	note 6
Montana	Exempt	Oil & Gas Operator	
Nebraska	Not affected	Undecided	note 6
New Mexico	Exempt	Oil & Gas Operator	
Oklahoma	Not affected	Oil & Gas Operator	note 6
Utah	Exempt	Oil & Gas Operator	
Washington	Exempt	Coal Operator	note 7
Wyoming	Exempt	Oil & Gas Operator	

Table 8, Ownership Notes

Note 1. A meeting is scheduled June 28, 1995 between the Oil & Gas Operators and the Coal Operators to discuss how to handle the royalty and ownership issues. If this meeting is a success, rules from these discussions will be promulgated. In addition, Kentucky is currently proceeding along the lines of the state of Pennsylvania, and is considering, as its first choice, to opt out of its "affected" status and proceed entirely within the State regulations (Kentucky Coal Facts, 1992). The issue as to whether a state can actually opt out of its "affected" status is not clear.

Note 2. It is not clear how Ohio became an "affected state" since no coal bed methane is currently being produced in this state. Rules for ownership have not been decided, nor does there appear to be any activity in the legislature in this area. Since much of Ohio's coal is shallow, the amount of reserves, although unknown, are probably small.

Note 3. In Illinois, the ownership issue has been resolved in favor of the coal operator. There is, however, no reporting required as to coal bed methane or coal mine methane production, so amounts are unknown. There is some private production from abandoned coal mines, but amounts are probably small and unknown.

Note 4. Ownership questions have definitely impeded coal mine/bed methane production in Pennsylvania. The state does not want federal regulation and has been unable to resolve ownership issues, so has adopted a policy which removes the state from the federal "affected" status. This strategy will help in neither the resolution of ownership nor in implementing the federal mandate to encourage coal mine/bed methane production.

Note 5. Tennessee has decided to let the DOI regulate production within the state. This decision was affected by two factors. The first is that the state Oil and Gas Board is undermanned and underfunded and cannot accept further responsibilities. The second is that, despite Tennessee's proximity to high coal mine/bed methane producing states, there is no current activity and the amount of usable reserves appears to be minimal.

Note 6. These states have no current activity in this area. Since they are not affected states, ownership issues are moot. In most the reserves are limited also. In states such as Oklahoma and Arkansas where some reserves are associated with the Arkoma basin, little interest is generated since regular gas is abundant separately from coal deposits (Forgotson, 1993; Friedman, 1989, 1995). Some interest has been expressed in these two states, but no activity is ongoing.

Note 7. Although estimates in the Western Washington basin show considerable gas reserves, none is currently produced. The problem stems from large amounts of water associated with this coal bed methane which must be removed before the gas can be recovered. The companies with interest, PetroTrends, Inc. and Northwest Fuel Development Corp. have apparently gone out of business.

Coal Bed Methane Reserves

Known coal bed/mine methane reserves are estimated at about 400 TCF in the continental United States. Only about 40 percent or 160 TCF are probably readily producible. In addition there are estimates of another 300 TCF of undiscovered reserves. This number is strictly an estimate from the Bureau of Mines, but allows for a reasonable amount of as yet undiscovered methane-containing minerals to be found. Therefore the available coal bed/mine methane for production is likely about

300 TCF in the continental United States. No data are included from Alaska, where much uncharted territory exists. In 1994 an estimated 63 BCF of methane from coal beds/mines was produced. Assuming an increasing production over the next decade, the reserves still will last for several hundred years (Kruger, 1994). About 2/3 of the 63 BCF of production was strictly from coal bed gas wells. The largest portion of the gas from mining operations comes from Alabama and Virginia, where the above mentioned ownership issues have been resolved. Since West Virginia has recently resolved its ownership issues, it will be interesting to follow methane production in this state over the next few years. It is readily predicted that production will rapidly reach the BCF/yr levels if the history in Alabama and Virginia are good indicators.

Significance

The biological production of SCP (or methanol) from methane may be the only viable technology that can be applied to the large quantities of dilute coal mine methane concentrations found in ventilation gas. In addition, however, the technology works well for the conversion of the higher methane concentrations found in gob gas. By utilizing this technology, methane emissions from wells are reduced and a valuable animal feed supplement is produced. It is estimated that 1.4 MM tons of SCP can be produced from only 10 percent of the 300 MMCFD of vent gas produced in the U.S. Economic projections show that the payout for a typical sized JWR vent gas facility producing SCP would be 2.1 years.

TASK 3. TECHNOLOGY APPLICATION

Arguably the best method for removing and utilizing methane at the intermediate to low concentrations found in vent and gob gases is through biological conversion. Coal mine methane may be converted to methanol and single cell protein (SCP) by the action of methylotrophic bacteria. High yields and fast rates are possible using this technology. More importantly methanol and SCP are higher value products than either natural gas or electricity. In addition, the production of SCP represents a significant energy savings. The energy to produce soybeans (an alternative to SCP) is estimated at 11.3 million BTU/ton protein produced while the energy to produce SCP from methane is only 6 million BTU/ton protein.

The most important application of the biological process to convert methane gas to SCP is in the mine fan exhaust since this represents a tremendous resource that is not readily used by any other technology. However, the SCP process is not limited to this application. Higher concentration gas streams can also be utilized. Special considerations for high methane concentration reactors will be needed to prevent methane ignition as the gas passes through the 5-15 percent explosive range. There may be applications where access to pipelines from pre mining wells is too expensive, or where a post mining well gas concentration is too low to upgrade to pipeline quality or other use. Another potential application is to an abandoned mining situations where an SCP plant was already in operation at the mine and after mining has been completed, the remaining lower volume gas production from the mine might be used to continue profitable operation, especially considering the increased value of the SCP versus methane. The ability to continue an industrial operation beyond the normal mine life not only continues employment in the area, it also helps to use methane that otherwise would escape into the environment.

The concept of SCP production from dilute fan gas streams is unique. With the exception of using small fractions of the mine fan exhaust air as combustion air for boilers or engines, there are no other economical alternatives for using the methane from this source. The use of vent gas as combustion air for the JWR mines would require the construction of nine large 500 megawatt power plants. Membrane, cryogenic, or other concentrating technologies all require excessive energy to be viable. Once diluted, entropy prevents methane from self separating and energy must be expended to separate the gas.

Process Description

The concept of biological production of either SCP or methanol from coalbed methane is quite simple and is shown diagrammatically for SCP production in Figure 7. Methane from gob wells or ventilation air would be introduced into a bioreactor containing a culture of (non-pathogenic) methanotrophic bacteria, where the conversion of methane and air to SCP or methanol takes place. Streams containing either intermediate to high concentrations of methane or the dilute methane in the ventilation air can be utilized. Schematics of reactors in conjunction with gob gas and ventilation air were described previously in Figures 3-6. A variety of bioreactors with high mass transfer coefficients could be used for this application, including the CSTR, trickle bed, spray column and immobilized cell reactor.

The reactors would operate at ambient temperature. The bacteria grow with methane as the substrate and produce 0.2-1.0 g cells per g methane as SCP or 5.3 gal of methanol per MSCF methane depending upon the strain. An equal volume of oxygen is also required for growth, such that dilute methane in air is a prerequisite for this process. Nutrients are also required and are supplied in the culture medium.

If SCP is desired, the bacterial cell mass from the reactor would be collected and the SCP dried for sale as animal feed. Methanotrophs are about 75 percent protein and have been shown to be an excellent substitute for soya meal, fish meal, etc. in animal or poultry diets (Sharp, 1990). If methanol is desired, the process would be stopped at the intermediate methanol prior to conversion to cell mass. Methanol would then be recovered by extraction and distillation.

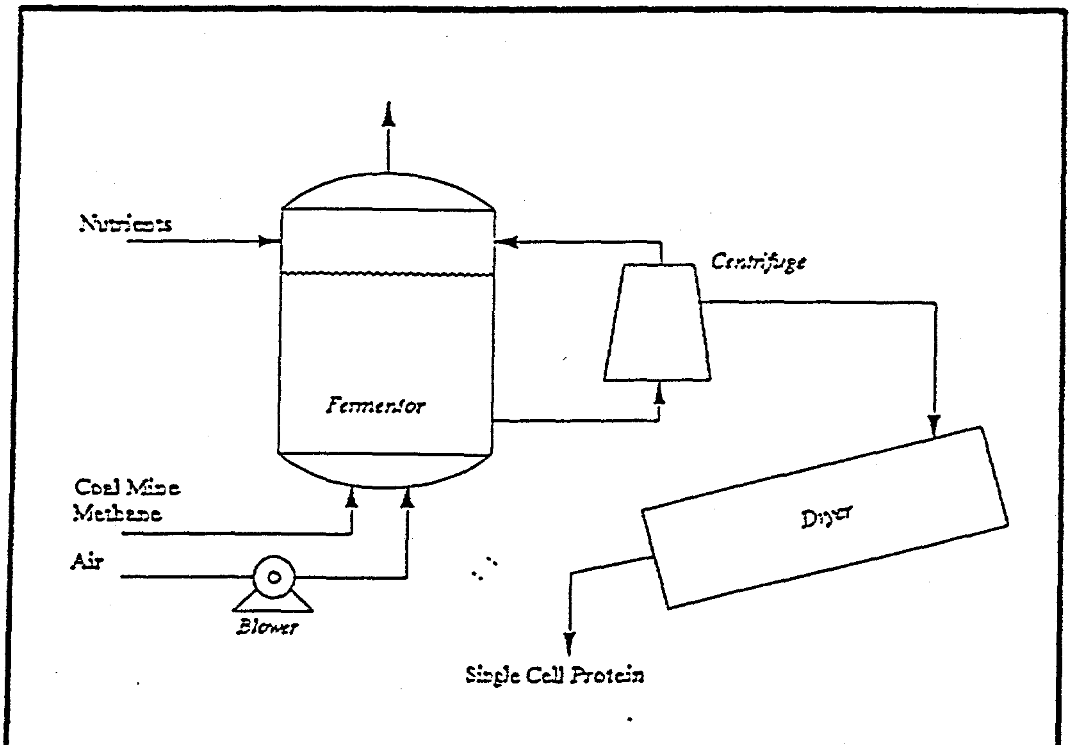

Figure 7. Flow Diagram for the Production of Single Cell Protein from Coal Mine Methane

Microbiology and Biochemistry of SCP and Methanol Formation

A detailed discussion of the microbiology and biochemistry of SCP and methanol formation is shown in Appendix C. There are many bacteria, and some yeasts, that oxidize methane to methanol. The methylotrophs also produce formaldehyde and formate intracellularly and formaldehyde is assimilated into biomass (SCP). The cell derives energy from the production of formate and CO_2, whereas the production of methanol requires energy. Cell free systems are not promising for methanol production, however, whole systems offer good potential for methanol production.

In order to accumulate methanol *in vitro*, the methylotroph must have a higher enzyme activity for methane monooxygenase than for methanol dehydrogenase. These activities will be a function of bacterial strain, dehydrogenase inhibitors, or monooxygenase activators. Furthermore, methanol may be used by MMO to supply energy for the cells when methane or oxygen are not available. Methylotrophs have been identified that accumulate methanol.

A high yield of methanol from methane is theoretically possible. The maximum possible yield is 50-67 percent and these yields have been achieved experimentally in the BRI laboratories.

Summary of Past BRI Research Results

1. SCP Production

As was mentioned previously, many strains of methanotrophs have been utilized for SCP production from methane in the past. Most, if not all of these strains, utilized > 20 percent methane as the feedstock and were not concerned with the 1-2 percent methane concentrations typically found in coal mine exhaust vent shafts.

Various strains of methanotrophs were screened by BRI in batch culture to select the best culture for use in continuous reactor studies. Strain F1L was selected for use after performing detailed culture selection and preliminary culture optimization studies. Strain F1L grows on an inexpensive medium and produces high cell yields at a variety of gas compositions.

Continuous reactor studies were performed with strain F1L in a CSTR with cell recycle in converting methane and oxygen to single cell protein. Two gas compositions were studied:

- Gas A, containing 17% CH_4, 17% O_2 and 66% N_2 (an equimolar ratio of CH_4 and oxygen in air), and
- Gas B, containing 2% CH_4, 20.6% O_2 and 77.4% N_2 (2% CH_4 in air)

Tables 9 and 10 show steady state summaries of CH_4 conversion, dry cell weight concentrations and cell yields at various gas and liquid retention times for the two gas mixtures. The O_2 and CH_4 conversions were essentially equal for the equimolar gas mixture. Also, the cell yield on O_2 was constant at 0.3 g/g and the cell yield on CH_4 was essentially constant at 0.65 g/g. The CH_4 conversions ranged from 90 percent at 40 min gas retention time to 52 percent at a 2 min gas retention time. Table 10 shows CH_4 conversions which range from 55 percent at a 7.6 min gas retention time to 36 percent at a 2.7 min gas retention time.

Tables 9 and 10 also present the mass transfer coefficients for the CSTR systems. These relatively constant coefficients indicate that the systems are limited by their ability to transfer CH_4 and

O_2 from the gas phase to the liquid phase. Reactors (contacting devices) with higher mass transfer coefficients than the CSTR at atmospheric pressure will maximize conversion at low gas retention times. Other potential reactor systems for dilute methane conversion to SCP, include the high pressure CSTR, the trickle bed reactor and the spray chamber. These reactors will be a focus of the Phase II studies.

Table 9. Steady State Conversion of Methane to SCP by Strain F1L in the CSTR (17% CH_4 in Air)

Gas Retention Time (min)	Liquid Retention Time (hr)	CH_4 Conversion (Percent)	Dry Cell Weight Concentration (g/L)	Cell Yield (g/g) on		
				O_2	CH_4	K_La,hr^{-1}
39.6	10.8	90	1.8	0.3	0.65	369
20.4	10.8	80	2.4	0.3	0.6	339
7.7	10.8	58	5.0	0.3	0.65	331
2.2	4.45	52	10.0	0.5	0.4	996

Table 10. Steady State Conversion of Methane to SCP by Strain F1L in the CSTR (2% CH_4 in Air)

Gas Retention Time (min)	Liquid Retention Time (hr)	CH_4 Conversion (Percent)	Dry Cell Weight Concentration (g/L)	Cell Yield (g/g) on		
				O_2	CH_4	K_La,hr^{-1}
7.6	10.8	55.3	0.62	0.33	0.67	354
4.5	10.8	45.5	0.96	0.37	0.72	407
2.7	10.8	36.1	1.28	0.35	0.77	450

Significance. Strain F1L was utilized successfully in the CSTR with cell recycle in converting gas mixtures of 2 percent and 17 percent CH_4 in air to SCP. High yields and fast rates are achieved. The reaction is mass transfer limited, and alternative reactors that achieve higher values of K_La should be used. A trickle bed reactor can operate at a gas retention time of only 32 sec in converting coal mine ventilation air containing 2 percent CH_4 to SCP.

2. Methanol Production

Several strains of methanotrophs were also screened for their ability to produce methanol from methane and oxygen. These studies showed that *Methylosinus trichosporium*, OB3b, and BRI strain F1L were most appropriate for methanol production. Studies to increase the relative activity of MMO showed that the addition of low concentrations of EDTA were sufficient to maximize methanol production.

Table 11 shows methanol production results in the CSTR as a function of liquid retention time using Isolate F1L. EDTA (1mM) was added to the medium to promote MMO activity. The reactor was fed a gas consisting of 50 percent CH_4 and 50 percent O_2 at 37°C and an agitation rate of 700 rpm. A constant gas retention time of 88.2 min was employed. The gas retention time controls the reactor volume, therefore, a large liquid retention is beneficial. As is noted in the table, a methanol concentration of 3.8 g/L can be achieved in the product stream. Higher concentrations are possible with extractive fermentation and high pressure operation. Again, alternative reactor schemes such as trickle bed reactors are desirable to maximize the mass transfer of CH_4 and oxygen and therefore the conversion to methanol.

Table 11. Steady State Conversion of Methane to Methanol by Strain F1L in the CSTR (50% CH_4, 50% O_2)

Liquid Retention Time (hr)	Cell Concentration (g/L)	Methanol Concentration (g/L)	Productivity (mmol/hr)
208	0.7	3.8	0.0274
132	0.52	2.8	0.0319
97	0.28	2.0	0.0312
37	0	0	0

Economic Projections

1. SCP Production

Economic projections were prepared for converting 15 million SCFD of coal mine methane to SCP. The process used is essentially identical to the process described previously in Figure 5. Two cases were considered:

- conversion of 17 percent CH_4 in air in a trickle bed bioreactor, and
- conversion of 2 percent CH_4 in air in a fixed film bioreactor

The capital costs for treating 17 percent CH_4 in air including blowers, reactors, pumps, a centrifuge and a dryer are shown in Table 12, and total $13 million. The CH_4 in air is converted into SCP in a trickle bed reactor. The economic analysis for this case, presented in Table 13, shows that 76,000 tons of SCP are produced per year, generating a revenue of $16.7 million/yr at current soybean prices. The operating costs including raw materials, utilities, labor, maintenance, depreciation and taxes and insurance total $5.6 million/yr or $73.80 per ton of SCP. The gross profit is $11.1 million/yr and the cash flow is $7.95 million/yr. The return on investment is 47.6 percent, with a payout of 2.1 years. If the more dilute methane stream (2 percent) is used in a fixed film bioreactor, the capital investment increases to $25.1 million and the return is still a very attractive 27 percent per year. If a spray reactor is used directly in the mine shaft, the capital costs are reduced significantly.

Table 12. Fixed Capital Investment

BIOLOGICAL PRODUCTION OF SCP FROM WASTE METHANE
15 million SCFD CH_4 (17 percent) - Trickle Bed Reactor

Equipment Item	Capital Cost, M$
Blower (2 atm)	1,410
Bioreactor	5,200
Circulation Pumps	1,160
Centrifuge	3,640
Dryer	1,660
TOTAL	$13,070

Table 13. Economic Analysis

BIOLOGICAL PRODUCTION OF SCP FROM WASTE METHANE
15 million SCFD CH_4 (17 percent) - Trickle Bed Reactor

	M$ per year
Revenue - 76,000 Tons SCP/yr @ $220/ton	$16,690
Operating Cost	
Raw Materials	1,260
Utilities - Electricity	1,330
Steam	360
Labor/Supervision/Fringe	450
Maintenance - 5% FCI	650
Depreciation - 10% FCI	1,300
Insurance/Taxes - 2%	260
TOTAL OPERATING COSTS	5,610
UNIT COST (TON)	$ 73.80
Gross Profit	11,080
Income Taxes - 40 percent	4,430
Net Profit	6,650
Cash Flow	7,950
Return	47.6 percent
	2.1 years

2. Methanol Production

Projections were also prepared for methanol production from a 50%-50% mix of CH_4 and air. Again, a plant size of 15 million SCFD of methane was utilized. The capital costs for this operation total $12.9 million. The revenue at $0.60/gal totals $16.7 million/yr. The gross profit is $12.2 million/yr and the cash flow is $8.6 million/yr. The return on investment is 67 percent and the payout is 1.5 years.

Significance. The economics of converting coal mine methane to SCP and methanol are potentially quite attractive. Economic projections show that SCP can be produced from waste methane streams for about $74 per ton and return 48 percent per year. The production of methanol from coal mine methane yields a payout time of 1.5 years.

SCP Production Potential

Ventilation gas, because of its low methane concentration of only 0.5 - 1.0 percent, cannot be easily recovered and utilized for power generation. The total methane ventilation emissions from all U.S. mines is approximately 300 MMCFD and the worldwide emissions are estimated to be about 1 BCFD. Converting all the U.S. emissions into SCP would yield about 1.4 MM tons of SCP per year. However, for logistical reasons and reasons of economics, not all of this gas will be available for conversion to SCP. In addition, it may not be possible to use all of the methane from a 0.5 percent gas stream. If only 10 percent of the vent gas can be utilized, 140,000 tons of SCP could be produced from this gas ventilation stream on an annual basis.

JWR has four mines liberating a total of approximately 60 MMCF/day of vent gas. Conversion of this gas to SCP would yield about 280,000 tons/yr of product. If 10 percent of this gas could be utilized, 28,000 tons/yr of SCP would be produced. If the market warrants, additional gob gas is available for SCP production.

Markets for SCP

SCP has a very large market as an animal feed as a substitute for soya meal, fish meal, etc. in animal or poultry diets (Sharp, 1990). The potential market for SCP is large and the price is high. The current world production of all protein products is about 200 million tons annually. Prices are approximately $500 per ton of protein, which would give a price of $375 per ton of SCP (biomass). This price translates into a value of $8.33 per MSCF methane, far more than current natural gas prices. Even with SCP at $220/ton (the current soybean price) a coal mine producing 15 million SCFD of methane (typical of a JWR mine) could generate an additional $17 million annually in revenue from the vented methane. If methanol is desired, the process would be stopped at the intermediate methanol prior to conversion to cell mass. Methanol would then be recovered by extraction and distillation.

Although the concept of producing SCP and methanol from coal mine methane is unique, the production of SCP from hydrocarbons is commercial technology. As world protein shortages were perceived in the late 1960's, significant research efforts were initiated to investigate microbial protein production from mineral and hydrocarbon sources, both in the U.S. and Europe (Sharp, 1990). Fungal, algal and bacterial processes were developed. The protein quality for various microbial proteins was demonstrated for animal and human consumption (Goldberg, 1985a; Moo-Young and Gregory, 1986). The substrates for these processes included CO_2, alcohols, n-paraffins, molasses, sulfite wastes, etc. These processes were all deemed technical successes, but some were economic failures, primarily because of the sharp increases in petroleum prices in the late 1970's and early 1980's. No plants were built utilizing methane as the substrate, although the microbiology was investigated.

The use of coal mine methane to produce methanol and SCP will utilize more dilute concentrations than have been previously investigated. BRI has demonstrated that strain F1L is capable of converting a wide range of methane concentrations, including 1-2 percent methane in ventilation air and highly concentrated methane from gob wells. By using a hollow fiber membrane for effluent withdrawal, cell (SCP) concentrations as high as 30 g/L have been achieved. Gas retention time, which controls reactor volume, has been reduced to as low as 30 sec by utilizing reactors with high mass transfer coefficients.

Tyson Foods has expressed an interest in SCP production from the process as a poultry feed supplement. A letter of support of the technology was attached in Task 2.

Task Significance

The biological concepts of producing SCP or methanol from methane in intermediate or dilute gas streams has been demonstrated in the BRI laboratories. This technology can be readily applied to vent gas and poor quality or even higher gob gas coal mine methane streams. The feasibility of SCP production from dilute gas streams has been proven and a large market exists. The economics of the technology are quite attractive and commercial interest exists in utilizing SCP as a poultry feed supplement. With this technology, at least 10 percent of vent gas methane at JWR (1.5 MMCFD) could be captured and converted, for a net recovery efficiency of 100 percent.

FUTURE WORK

The feasibility of utilizing a biological process to convert coal mine methane to SCP and/or methanol has been demonstrated in the Phase I studies. Additional development will be required to move the technology through demonstration and on to the commercial phase.

Phase II will be a conceptual design for the Phase III demonstration of the biological process, aimed at commercializing the resource and substantially reducing methane emissions associated with coal mining. Five tasks will be carried out. First, a conceptual design will be prepared and associated costs will be developed. The design can utilize a variety of reactor schemes including the CSTR with cell recycle, the trickle bed reactor, the immobilized fixed film reactor and the spray column. Thus, as a first step in preparing the conceptual design, the feasibility of using these and other reactor schemes either above ground or in the exhaust air ducts will be investigated and demonstrated in the laboratory.

Secondly, the impact of the technology on the environment will be assessed, including an updated estimate of the significant potential reduction in methane emissions to the atmosphere and identification of incremental environmental effects that will result from the application of the technology. The market potential for the SCP and methanol products will be evaluated, including product demand, pricing shipping and other factors affecting marketability and economics. As a part of this task, the data will be incorporated into an economic analysis of the proposed project.

The fourth task will be the preparation of a conceptual design and evaluation study to permit evaluation for demonstration purposes. This study will include the parties and agreements, site location, projected reductions in emissions, the size of the demonstration and the costs of the demonstration. Finally, a report will be prepared, containing the results of the Phase I and Phase II studies.

Phase III Demonstration

The Phase III program will be a demonstration of SCP production from coal mine vent gas at the JWR coal mines in Alabama prior to commercialization of the technology. The demonstration program will require two years for completion, and will consist of the following tasks:

- Design of the Experimental Program
- Site Selection
- Construction of Bioreactor/SCP Purification Facilities
- Production of Inocula
- Technical Demonstration and Data Interpretation
- SCP Feeding Trials in collaboration with Tyson Foods
- Detailed Market Development/Commercialization Strategy

An above ground demonstration of the technology including SCP production, protein recovery and protein purification will take place. The demonstration will utilize the most suitable reactor type for SCP production, resulting from the Phase II studies, and be applied to mine vent gas.

The experimental program will be designed to yield rate data for process scale-up, and will be designed to answer any technical uncertainties found in the Phase II studies. The location will be selected by JWR in consultation with BRI and the USBM. Inocula for the trials will be generated on site.

An important part of the demonstration will be feed trials at Tyson Foods, who will evaluate the SCP as a poultry feed supplement. Tyson Foods will be provided with sufficient quantities of the SCP to demonstrate the ability of the SCP to replace other protein sources in the poultry diet. Detailed market development/commercialization strategies, beyond the scope of Phase II, will be developed with the aid of Tyson Foods.

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APPENDICES

Appendix A. State Contacts for Gas Production/Emission Data

Alabama. Larry Rings, Rick Hamilton, Alabama Geological Survey (Tuscaloosa), 205-349-2852.

Arkansas. Oil and Gas Commission, 501-862-4965.

Colorado. Debbie Baldwin, Ed DeMario, Oil and Gas Conservation Commission, 303-894-2100.

Illinois. Duane Pulliam, Department of Mines and Minerals, Oil and Gas Division, 217-782-1286. Heinz Damberger, 217-333-4747.

Indiana. Mike Nicholas, OIl and Gas Division, 317-232-4055. Stan Keller, Energy Resources, Indiana Geological Survey, 812-855-5412. Denver Harper, Indiana Geological Survey, 812-855-1369.

Iowa. Bill Buttermore, Minerals, Energy Research Institute, Iowa State University, 515-281-4246.

Kentucky. M. Bowker, Kentucky Coal Marketing and Support Council, 502-564-2562. Margie Jones, Division of Energy, 502-564-2500. Bill Caylor, Kentucky Coal Association, 606-233-4743.

Montana. Ron Umscheid, Mining Supervisor, Labor and Industry Department, Board of Oil and Gas, 406-444-6401. James Mockler or Danette Warren, Montana Coal Council, 406-442-6223.

New Mexico. Ernie Bush, Frank Chavez, Oil Conservation Commission (Aztec), 505-334-6178. Roy Johnson, State Oil and Gas Commission, 505-827-8198.

Ohio. Nancy Gogel, Division of Oil and Gas, 614-265-6917. Sherry Weisgarber, Ohio Geological Survey, 614-265-6588.

Oklahoma. Greg Hudson, Corporation Commission, Division of Oil and Gas 405-521-3859. Mark Secrest, Corporation Commission, Legal Division, 405-521-3859. Sam Friedman, Oklahoma Geological Survey, 405-325-3031.

Pennsylvania. Ron Gilius, Oil and Gas Management Administration 717-782-2199. Jim Erb, Oil and Gas Management Administration, 717-782-2199. Cheryl Cogart (keeps field data) 412-442-4235. Tony Markowsky, Oil and Gas Management Administration, 717-787-2169. John Harper or Leo Shrider, Nelder and Blake (Ohio, operate 2 producing fields), 412-442-4000.

Tennessee. Mike Hoyal, Betty Bledsoe, Tennessee Oil and Gas Board, 615-532-0166 (Hoyal), 615-532-0162 (Bledsoe).

Utah. Dave Darby, Ron Ferth, Department of Oil, Gas and Mining, 801-538-5340.

Virginia. James Smith, Steve Wallace, Department of Mines, Minerals and Energy, 804-692-3211.

Washington. Mark Anderson, Washington State Department of Energy, 360-956-2012. Terry Mitchell, PetroTrends Inc., 900 Melbourne Tower, 1511 3rd Ave., Seattle, Wa 98101, 206-628-8903. Dr. Peet M. Soot, Northwest Fuel Development Corp., 7675 SW Miner Way, Portland, OR 97225, 503-699-9836.

West Virginia. Mike Lewis, Oil and Gas Commission, 304-759-0516.

Wyoming. Dale Adamly, Department of Public Lands - Minerals, 307-777-6629. Gary Glass, Wyoming Geological Survey (Laramie), 307-766-2286.

General Sources.

Peter Schwocko, Colorado School of Mines, 303-273-3888.
Keith Murray, Coalbed Methane Forum (Denver), 303-237-3020.

Appendix B. Virginia Gas and Oil Act

Section 3. Virginia Gas and Oil Board Regulations

VIRGINIA GAS AND OIL BOARD REGULATION

VR 480-05-22.2

Issued by:

Virginia Gas and Oil Board

Commonwealth of Virginia
Department of Mines, Minerals and Energy
Division of Gas and Oil
230 Charwood Drive
P. O. Box 1416
Abingdon, VA 24210

Phone: (703) 676-5423

This regulation was adopted by the Virginia Gas and Oil Board on August 29, 1991.

This regulation replaces the emergency "Conservation Regulations for Gas and Oil" (VR 480-05-22.2)

The effective date of this regulation is October 23, 1991.

Table of Contents

Virginia Gas and Oil Board Regulations

VR 480-05-22.2 VIRGINIA GAS AND OIL BOARD REGULATIONS

§1. Definitions.--

The following words and terms, when used in this regulation, shall have the following meaning, unless the context clearly indicates otherwise:

"Act" means the Virginia Gas and Oil Act of 1990, Chapter 22.1 (§45.1-361.1 et seq.) of Title 45.1 of the Code of Virginia.

"Applicant" or **"petitioner"** means a person who files an application, petition, appeal or other request for Board action.

"Complete application" means all the materials required to be filed by the applicant under this regulation.

"Department" means the Department of Mines, Minerals and Energy.

"Director" means the Director of the Department of Mines, Minerals and Energy or his authorized agent.

"Directional survey" means a well survey that measures the degree of departure of a hole, or distance, from the vertical and the direction of departure.

"Division" means the Division of Gas and Oil of the Department of Mines, Minerals and Energy.

"Election" means the performance of an act within the time established or required by statute, order or regulation. An election required to be made by Board order or regulation must be in writing and (i) be personally delivered to the person or agent of the person described in the order or regulation by the date established or required, or (ii) be mailed to the person or agent of the person described in the order or regulation at the address stated therein and be postmarked by the United States Postal Service before midnight on the date established or required.

"Field" means the general area underlain by one or more pools.

"Gas/oil ratio" means the product of the number of Mcf of natural gas produced from a well divided by the number of barrels of oil produced from the well as determined by a gas/oil ratio test.

"Gas well" means any well which produces or appears capable of producing a ratio of 6,000 cubic feet (6 Mcf) of gas or more to each barrel of oil, on the basis of a gas-oil ratio test.

"Inclination survey" means a well survey to determine the deviation, using the surface location of the well as the apex, of a well bore from the true vertical beneath the apex on the same horizontal subsurface plane.

"Metes and bounds" means the boundary lines of land, with their terminal points, angles and distances.

"Mcf" means, when used with reference to natural gas, one thousand cubic feet of gas at a pressure base of 14.73 pounds per square inch gauge and a temperature base of 60°F.

"Mine development plan" or **"Registered operations plan"** means a plan filed with the Division of Mines or the Division of Mined Land Reclamation as part of the licensing or permitting for the legal permission to engage in extraction of coal resources.

"Oil well" means any well which produces or appears capable of producing a ratio of less than 6,000 cubic feet (6 Mcf) of gas to each barrel of oil, on the basis of a gas-oil ratio test.

"Pooling" means the combining of all interests or estates in a gas, oil or coalbed methane drilling unit for the development and operations thereof. Pooling may be accomplished either through voluntary agreement or through a compulsory order of the Board.

"Respondent" means a person named in an application, petition, appeal or other request for Board action and against whom relief is sought by the applicant, or a person who under the terms of a Board order, is required to make an election.

"Unit operator" means the gas or oil owner designated by the Board to operate in or on a pooled unit.

§2. Authority and Applicability.--

A. This regulation is promulgated by the Virginia Gas and Oil Board pursuant to §45.1-361.15 of the Code of Virginia.

B. This regulation replaces the emergency Conservation Regulations for Gas and Oil, VR 480-05-22.2.

C. As provided for in the Virginia Acts of Assembly, 1990, Chapter 92, all field rules and orders issued pursuant to the provisions of the Oil and Gas Act of 1982, Chapter 22 (§45.1-286 et seq.) of Title 45.1 of the Code of Virginia shall remain in force and effect until modified or revoked pursuant to the provisions of the Gas and Oil Act of 1990, Chapter 22.1 (§45.1-361.1 et seq.) of Title 45.1 of the Code of Virginia. The requirements of this regulation are in addition to requirements of field rules and orders.

§3. Administrative Provisions.--

A. The Virginia Gas and Oil Board shall meet on the third Tuesday of each calendar month unless no action is required by the Board or unless otherwise scheduled by the Board. All hearings shall be scheduled in accordance with the requirements for notice by publication in §45.1-361.19 of the Code of Virginia. Except where otherwise established by the Act, the Board may establish deadlines for filing materials for meetings or hearings scheduled on other than the third Tuesday of each month.

B. Applications to the Board must be filed by the following deadlines:

1. All applications, petitions, appeals or other requests for Board action must be received by the Division at least 30 calendar days prior to the regularly scheduled meeting of the Board.

2. When required, the following material must be filed with the Division at least seven calendar days prior to the regularly scheduled meeting of the Board in order for the application to be considered a complete application:

    a. the affidavit demonstrating that due diligence was used to locate and serve persons in accordance with §45.1-361.19 of the Code of Virginia and §4 of this regulation; and
    b. proof of notice by publication in accordance with §4.D of this regulation.

C. A complete application that is not filed by the deadlines of this subsection shall be carried over to the next scheduled meeting of the Board. A submission that does not contain a complete application shall not be considered by the Board until the application is complete.

D. The Division shall assign a docket number to each application or petition at the time of filing, and shall notify the applicant of the docket number. The docket number shall be referenced when submitting material regarding the application or petition.

E. In addition to the other requirements of this regulation, applications to the Board shall meet the following standards:

1. Each application for a hearing before the Board shall be headed by a caption which shall contain a heading including:

    a. "Before the Virginia Gas and Oil Board";

b. the name of the applicant;
c. the relief sought; and
d. the docket number assigned by the Division.

2. Each application shall be signed by the applicant, an authorized agent of the applicant, or an attorney for the applicant, certifying that, "The foregoing application to the best of my knowledge, information, and belief is true and correct."

3. Exhibits shall be identified by the docket number and an exhibit number and may be introduced as part of a person's presentation.

4. Persons shall submit 10 sets of each application and exhibit. Each person offering exhibits into evidence shall also have available a reasonably sufficient number of exhibits for other persons who are subject to the provisions of §§45.1-361.19 and 45.1-361.23 of the Code of Virginia and are expected to be in attendance at the hearing.

F. Applications for the establishment of units, spacing or pooling shall be accompanied by a $100 non-refundable fee, payable to the Treasurer of Virginia.

G. All parties in any proceeding before the Board are entitled to appear in person or by counsel or other qualified representative, as provided for in the Administrative Process Act, §9-6.14:1 et seq. of the Code of Virginia.

§4. Notice of Hearings.--

A. Each applicant for a hearing to establish field rules, drilling units or who seeks to pool interests in a drilling unit under §§45.1-361.20, 45.1-361.21 or 45.1-361.22 of the Code of Virginia shall provide notice in accordance with §45.1-361.19 of the Code of Virginia.

B. Each applicant for a hearing to establish an exception to statewide spacing under §45.1-361.17 of the Code of Virginia shall provide notice by certified mail, return receipt requested, to all gas, oil, coal or mineral owners having an interest underlying any tract located within the distances provided in §45.1-361.17 of the Code of Virginia or the distance to the nearest well completed in the same pool, whichever is less. Each applicant for a hearing to establish an exception to a well location provided for in a drilling unit established by an order of the Board shall provide notice by certified mail, return receipt requested, to all gas, oil, coal or mineral owners having an interest underlying the unit where the exception is requested.

C. Each applicant shall include, with the mailed notice of the hearing, a copy of his application or petition to the Board.

D. When the identity or location of any person to whom notice is required to be given in accordance with subsections A or B of this section is unknown at the time the applicant applies for a hearing before the Board, the applicant for the hearing shall cause a notice to be published in a newspaper of general circulation in the county, counties, city, or cities where the land or the major portion thereof which is the subject of the application is located. The notice shall include:

1. the name and address of the applicant;

2. a description of the action to be considered by the Board;

3. a map showing the general location of the area which would be affected by the proposed action or a description which clearly describes the location or boundaries of the area which would be affected by the proposed action sufficient to enable local residents to identify the area;

4. the date, time and location of the hearing at which the application is scheduled to be heard; and

5. where interested persons may obtain additional information.

E. Notice of a hearing made in accordance with §45.1-361.19 of the Code of Virginia or this section shall be sufficient, and no additional notice is required to be made by the applicant upon a postponement or continuance of the hearing.

F. Each applicant for a hearing to modify an order established under §45.1-361.20 of the Code of Virginia shall provide notice in accordance with §45.1-361.19 of the Code of Virginia to each person having an interest underlying the tract or tracts in the area to be affected by the proposed modification.

G. An applicant filing a petition to modify a forced pooling order established under §45.1-361.21 or §45.1-361.22 of the Code of Virginia to change the unit operator based on change of the corporate name of the unit operator, change of corporate structure of the unit operator or transfer of the unit operator's interests to any single subsidiary, parent or successor by merger or consolidation is not required to provide notice. Each other applicant for a hearing to modify a forced pooling order shall provide notice in accordance with §45.1-361.19 of the Code of Virginia to each person having an interest in the unit which interest may be affected by the proposed modification.

§5. Applications for Field Rules.--

A. Each application filed under §45.1-361.20 of the Code of Virginia to establish or modify a field rule, a drilling unit or drilling units shall contain:

1. the name and address of the applicant and the applicant's counsel, if any;

2. in the case of an application to vacate or amend an order, identification of the order to be vacated or amended;

3. a statement of the relief sought and the proposed provisions of the order or a proposed order;

4. citations of statutes, rules, orders, and decided cases supporting the relief sought;

5. in the case where a field rule is proposed to be established or modified:

   a. a statement of the type of field (gas, oil or coalbed methane gas);
   b. a description of the proposed formation or formations subject to the petition; and
   c. a description of the pool or pools included in the field, based on geological and technical data, including a metes and bounds description of the boundaries of the pool or pools and field, referenced to and located on a United States Geological Survey, 7.5-minute topographic map or maps. Effective October 1, 1992, the Virginia Coordinate System of 1927 as defined in Chapter 17 (§55-287 et seq.) of Title 55 of the Code of Virginia, also known as the State Plane Coordinate System, shall be used to describe and locate the boundaries of the pool or pools. Applicants are encouraged to use the State Plane Coordinate System prior to October 1, 1992;

6. in the case where a drilling unit or units are proposed to be established or modified:

   a. a statement of the acreage to be embraced within each drilling unit;
   b. a description of the formation or formations to be produced by the well or wells in the unit or units; and
   c. a metes and bounds description of the boundaries of the drilling unit or units, referenced to and located on a United States Geological Survey, 7.5-minute topographic map or maps in accordance with the standards for use of the State Plane Coordinate System of subdivision A.5.c. of this section;

7. a statement of the amount of acreage to be included in the order;

8. a statement of the proposed allowable production rate or rates and supporting documentation, if applicable;

9. evidence that any proposal to establish or modify a unit or units for coalbed methane gas will meet the requirements of §45.1-361.20.C of the Code of Virginia;

10. an affidavit demonstrating that due diligence was used to locate and serve persons in accordance with §45.1-361.19 of the Code of Virginia and §4 of this regulation;

11. when required, proof of notice by publication in accordance with §4.D of this regulation; and

12. copies of proposed exhibits.

§6. Applications for Exceptions to Minimum Well Spacing Requirements.--

A. Applications for an exception to statewide spacing under §45.1-361.17 of the Code of Virginia or under a field rule issued by the Board shall contain the following:

1. the name and address of the applicant and the applicant's counsel, if any;

2. in the case of an application for an exception to spacing established in a field rule, identification of the order governing spacing in the field;

3. a statement of the proposed location of the well in relation to permitted wells within the distances prescribed in §45.1-361.17 of the Code of Virginia;

4. a description of the formation or formations to be produced by the well proposed for alternative spacing and the formation or formations produced by neighboring wells;

5. a description of the spacing of other wells producing from the formation or formations to be produced by the well;

6. a description of the conditions justifying the alternative spacing;

7. an affidavit demonstrating that due diligence was used to locate and serve persons in accordance with §4 of this regulation;

8. when required, proof of notice by publication in accordance with §4.D of this regulation; and

9. copies of proposed exhibits.

§7. Applications to Pool Interests in a Drilling Unit: Conventional Gas or Oil or No Conflicting Claims to Coalbed Methane Gas Ownership.--

A. Applications filed under §45.1-361.21 of the Code of Virginia to pool interests in a drilling unit for conventional gas or oil or for coalbed methane gas where there are no conflicting claims to ownership of the coalbed methane gas, except as provided for in subsection B of this section, shall contain the following:

1. the name and address of the applicant and the applicant's counsel, if any;

2. in the case of an application to vacate or amend an order, identification of the order to be vacated or amended;

3. a statement of the relief sought and proposed provisions of the order or a proposed order;

4. citations of statutes, rules, orders, and decided cases supporting the relief sought;

5. a statement of the type of well or wells (gas, oil or coalbed methane gas);

6. the permit number or numbers, if any have been issued;

7. a metes and bounds description of area to be pooled;

8. a map showing the size and shape of the proposed unit and boundaries of tracts within the unit, which effective October 1, 1992, shall be referenced to the State Plane Coordinate System, the names of owners of record of the tracts, and the percentage of acreage in each tract to the total acreage of the unit, certified by a licensed land surveyor or a licensed professional engineer and attested by the applicant as to its conformity to existing orders issued by the Board;

9. a description of the status of interests to be pooled in the unit at the time the application is filed;

10. for an application to pool a coalbed methane gas unit, a statement of the percentage of the total interest held by the applicant in the proposed unit at the time the application for the hearing is filed;

11. a statement of the names of owners and the percentage of interests to be escrowed under §45.1-361.21.D. of the Code of Virginia for each owner whose location is unknown at the time the application for the hearing is filed;

12. a description of the formation or formations to be produced;

13. an estimate of production over the life of well or wells;

14. an estimate of the amount of reserves of the unit;

15. an estimate of the allowable costs in accordance with §10 of this regulation;

16. an affidavit demonstrating that due diligence was used to locate and serve persons in accordance with §45.1-361.19 of the Code of Virginia and §4 of this regulation;

17. when required, proof of notice by publication in accordance with §4.D of this regulation; and

18. copies of proposed exhibits.

B. Applications to amend an order pooling interests in a drilling unit may be filed by written stipulation of all persons affected. The application is not required to contain the information specified in subsection A of this section, but shall contain the proposed amended language to the order, shown by interlineation.

C. After the time for election provided in any pooling order has expired, the unit operator shall file an affidavit with the Board stating whether or not any elections were made. If any elections were made, the affidavit shall name each respondent making an election and describe the election made. If no elections were made or if any response was untimely, the affidavit shall so state. The affidavit shall be accompanied by a proposed supplemental order to be made and recorded to complete the record regarding elections. The affidavit and proposed supplemental order shall be filed by the unit operator within 20 days after the last day on which a timely election could have been delivered or mailed, or within 20 days after the last date for payment set forth in the pooling order, whichever occurs last. Applicant shall mail a true and correct copy of any supplemental order to all persons identified in the supplemental order.

§8. Applications to Pool Interests in a Drilling Unit: Conflicting Claims to Coalbed Methane Gas Ownership.--

In addition to the information required in §7 of this regulation, applications filed under §45.1-361.22 of the Code of Virginia to pool interests in a drilling unit for coalbed methane gas where there are conflicting claims to ownership of the coalbed methane gas shall contain a description of the conflicting ownership claims and the percentage of interests to be escrowed for the conflicting claims, and a plan for escrowing the costs of drilling and operating the well or wells and the proceeds from the well or wells attributable to the conflicting interests.

§9. Standards for Escrow Accounts.--

Payment of funds into escrow accounts shall be made in accordance with the standards established in each order of the Board requiring such payment. In addition, the unit operator of a drilling unit subject to a voluntary pooling agreement may petition the Board under §14 of this regulation for an order authorizing the escrow of funds subject to conflicting claims in accordance with Board standards or regulations regarding escrow of such funds in units subject to a compulsory pooling order.

§10. Allowable Cost Which May Be Shared in Pooled Gas or Oil Operations.--

A. The unit operator of a pooled unit may share all reasonable costs of operating the unit, including a reasonable supervision fee, with other participating and nonparticipating operators, as provided for in §45.1-361.21 of the Code of Virginia, which may include:

1. Direct Costs:

   a. ecological and environmental;
   b. rentals and royalties;
   c. labor;
   d. employee benefits;
   e. material;
   f. transportation;
   g. services;
   h. equipment and facilities furnished by the unit operator;
   i. damages and losses to joint property;
   j. legal expenses;
   k. taxes;
   l. insurance;
   m. abandonment and reclamation;
   n. communications; and
   o. other expenditures.

2. Indirect Charges:

   a. drilling and production operations;
   b. major construction; and
   c. catastrophe.

B. Where there are conflicting royalty claims to coalbed methane gas, the unit operator of a forced pooled coalbed methane gas unit shall deposit proceeds in accordance with §45.1-§361.22 of the Code of Virginia, to be determined at the wellhead.

C. Where there are conflicting claims and one or more persons have elected to become participating or nonparticipating operators, the unit operator of a forced pooled coalbed methane gas unit shall escrow net proceeds after deduction for royalty and other costs consistent with the terms of this regulation and the Board's order regarding the unit.

D. In any dispute which may arise regarding a unit operator's costs, the unit operator shall be entitled to the benefit of a presumption of reasonableness where it is shown that the types of costs being disputed are, by custom and practice, customary and usual within the industry. The unit operator shall not be entitled to a presumption of reasonableness of the amount of the costs being disputed.

§11. Recordkeeping.--

A. Each unit operator shall maintain records of production, income, payments made to lessors and other information prescribed by the Board, until the later of:

1. when the permits for all wells in the unit have been released by the Department;

2. twenty-four months after all escrowed funds for competing claims to ownership of coalbed methane gas in the unit have been paid out under order of the Board; or

3. when so ordered by the Board.

B. Each unit operator shall maintain records of all costs charged to participating or nonparticipating operators until the later of:

1. twenty-four months after all costs attributable to participating or nonparticipating operators have been settled and paid; or

2. when so ordered by the Board.

C. Upon transfer of the right to conduct operations in a pooled drilling unit to a new unit operator, the old unit operator shall transfer all records required to be maintained in accordance with this section to the new unit operator. The old unit operator will not be released from responsibility as the unit operator until he has submitted, to the Board, evidence that the records have been received by the new unit operator.

D. In the event a unit operator wishes to terminate its legal existence and the unit is not transferred to a new unit operator, or when the permit for any well in the unit has been revoked and the bond forfeited by the Department, the unit operator shall transfer, to the Board, all records required to be maintained in accordance with this section.

§12. Applications To Change the Unit Operator For A Unit Established by Order of the Board.--

A. The approval of the Board is not required to sell, assign or otherwise convey an operator's ownership interest in a unit or group of units unless the operator was appointed by Board order as the unit operator.

B. Voluntary transfer of the right to operate a unit established by the Board may be requested upon transfer of unit operations to a new operator. For a voluntary transfer, the proposed new unit operator shall file written notification of the transfer of operations and request the Board to amend the order to reflect the transfer. The notification shall include, but not be limited to:

1. the name and address of the existing unit operator;

2. the name and address of the proposed new unit operator;

3. written approval from the existing unit operator;

4. identification of the order to be amended;

5. a description of any changes in the percentage of interests in each tract pooled in the unit, including a statement of the percentage of interest held by the proposed new unit operator if the unit is for coalbed methane gas;

6. a description of any other changes to unit operations to be implemented by the proposed new unit operator;

7. an affidavit demonstrating that due diligence was used to locate and serve persons in accordance with §4 of this regulation; and

8. copies of proposed exhibits.

C. Involuntary transfer of the right to operate a unit established by Board order may be requested if the unit operator has not continued gas or oil operations of the unit with due diligence, or the permit for any well in the unit has been revoked by the Department. For an involuntary transfer, the proposed new unit operator shall file a written application to transfer the operations, including, but not limited to:

1. the name and address of the existing unit operator;

2. the name and address of the proposed new unit operator;

3. identification of the order which is sought to be amended;

4. a detailed statement of the facts supporting the removal of the existing operator;

5. a description of any changes in the percentage of interests in each tract pooled in the unit, including a statement of the percentage of interest held by the proposed new unit operator if the unit is for coalbed methane gas;

6. a description of any other changes to unit operations to be implemented by the proposed new unit operator;

7. an affidavit demonstrating that due diligence was used to locate and serve persons in accordance with §4 of this regulation; and

8. copies of proposed exhibits.

§13. Appeals of the Director's Decisions.--

A. Appeals of the Director's decisions shall be filed in writing, at the office of the Division, in accordance with §§45.1-361.23 and 45.1-361.36 of the Code of Virginia.

B. A petition to appeal a decision of the Director shall contain:

1. the name and address of the petitioner and the petitioner's counsel, if any;

2. identification of the decision being appealed, and the date the decision was issued;

3. a statement identifying the standing of the petitioner to appeal;

4. a statement setting forth the reasons for the appeal, including errors alleged in the Director's decision and the reasons why the decision is deemed contrary to law or regulation;

5. a statement that the issues on appeal were in fact raised as required by §45.1-361.36.B of the Code of Virginia;

6. a statement setting forth the specific relief requested;

7. when a stay to any proposed activity allowed as a result of the Director's decision is desired, a request for the stay and the basis for granting the stay; and

8. other information, relevant to the petition, the petitioner wishes to provide.

C. Upon receipt of an appeal containing a request for a stay, the Director shall decide on the request in accordance with §45.1-361.23.D of the Code of Virginia.

§14. Miscellaneous Petitions to the Board.--

A. Any petition to the Board not otherwise provided for in this regulation shall be made in writing, and shall contain:

1. the name and address of the petitioner and the petitioner's counsel, if any;

2. the names and addresses of any persons who are named as respondents in the petition;

3. an affidavit that notice has been given to each respondent, if any, named in the petition;

4. a statement of the issues of the petition;

5. a statement setting forth the specific relief requested; and

6. other information, relevant to the petition, the petitioner wishes to provide.

B. If a petitioner for a unit under §45.1-361.21 or §45.1-361.22 fails to provide notification to an owner of interest of any part of a unit subject to a petition before the Board, then such party may file a written objection to the proceedings in the form of a petition as set out in A of this section. Such petition does not require the submission of an application fee as required in §3.F of this Regulation.

§15. Effective Dates for Board Orders.--

A. All orders issued by the Board under §45.1-361.20 of the Code of Virginia shall remain in effect until vacated or amended by the Board on its own motion or on application from an owner or operator in the field or unit subject to the order.

B. All orders issued by the Board under §§45.1-361.21 and 45.1-361.22 of the Code of Virginia shall remain in effect:

1. for a period of one year from the date of issuance, if gas or oil operations have not commenced on the well or wells in the unit or units established by the order;

2. until the permit or permits have been released on the well or wells, if gas or oil operations have commenced on the well or wells within the unit or units established by the order; or

3. until vacated or amended by the Board on its own motion or on application from a gas or oil owner or the unit operator in the unit subject to the order.

C. Conditional orders issued by the Board under §§45.1-361.21 and 45.1-361.22 of the Code of Virginia shall remain in effect in accordance with the terms and conditions of the order, unless vacated or amended by an order of the Board.

§16. Enforcement.--

A. The Director shall enforce the provisions of the Act, this regulation or order of the Board, and may use the following methods:

1. notices of violation in accordance with §17 of this regulation;

2. closure orders in accordance with §18 of this regulation;

3. petitions to the Board to revoke any rights granted to operators by the Board;

4. emergency orders in accordance with §45.1-361.27.D of the Code of Virginia; or

5. any other action in accordance with the Code of Virginia.

B. A notice or order shall be served on the person to whom it is issued promptly after issuance, as follows:

1. by delivering a copy, by hand, to the person to whom the notice or order is issued or other employee or agent of the person; or

2. by sending a copy of the notice or order by certified mail, return receipt requested, to the person to whom the notice or order is issued or his designated agent.

C. Service shall be complete upon delivery of the notice or order, or of the mail, and shall not be deemed incomplete because of refusal to accept.

D. Nothing in this regulation shall prevent the Director from taking any action or from making efforts to obtain voluntary compliance through conference, warning or other means prior to issuing any enforcement notice or order.

E. The purpose of taking enforcement actions is to obtain compliance with the provisions of the Act, this regulation or order of the Board.

§17. Notices of Violation.--

A. The Director may issue a notice of violation if he finds a violation of Chapter 22.1 of Title 45.1 of the Code of Virginia, this regulation, or any order of the Board.

B. A notice of violation shall be in writing, signed, and set forth with reasonable specificity:

1. the nature of the violation;

2. a reasonable description of the activity or condition to which it applies;

3. the remedial action required, which may include interim steps; and

4. a reasonable deadline for abatement, which may include interim deadlines for accomplishment of interim steps.

C. The Director may extend the deadline for abatement or for accomplishment of an interim step if the failure to meet the deadline previously set was not caused by the person's lack of diligence. The total time for abatement under a notice of violation, including all extensions, shall not exceed 20 days from the date of issuance, except upon a showing by the person and acceptance by the Director that it is not feasible to abate the violation within 20 days, or if the deadline is extended during an appeal. An extension of the deadline for abatement may not be granted when the person's failure to abate within 20 days has been caused by a lack of diligence or intentional delay by the person.

D. The Director shall terminate a notice of violation by written notice when he determines that all violations listed in the notice of violation have been abated.

E. Any person issued a notice of violation may, before the deadline established for abatement for the violation, request, in writing to the Director, an informal fact finding hearing to review the issuance of the notice. The person is relieved of the duty to abate, during an appeal of the notice of violation to the Director or Board, any violation of Article 2 of the Act, this regulation or Board order, except as otherwise provided by regulation.

F. The Director shall conduct an informal fact finding hearing, in accordance with the Administrative Process Act, §9-6.14:11 of the Code of Virginia, no later than 10 days after receipt of the hearing request. The Director shall affirm, modify, or vacate the notice in writing, to the person who requested the hearing, no later than five days after the date of the hearing.

§18. Closure Orders.--

A. The Director may immediately order a cessation of operations or of the relevant portion thereof, when:

1. a gas or oil operator continues to produce in excess of an allowable production limit established by the Board after having been ordered by the Director or Board to stop production in excess of the allowable limit; or

2. repeated notices of violations have been issued for the same condition or practice.

B. A closure order shall be in writing, signed and shall set forth with reasonable specificity:

1. the nature of the condition, practice or violation;

2. a reasonable description of the activity or condition to which it applies;

3. the remedial action required, if any, which may include interim steps; and

4. a reasonable deadline for abatement, which may include interim deadlines for accomplishment of interim steps.

C. A closure order shall require the person to take all steps the Director deems necessary to abate the violations covered by the order in the most expeditious manner possible.

D. The Director shall terminate a closure order by written notice when he determines that all conditions, practices or violations listed in the order have been abated.

E. Any person issued a closure order may request an informal fact finding hearing to review the issuance of the order, in writing to the Director, within 10 days from receipt of the order. The person may request an expedited hearing, in writing to the Director, within three days of receipt of the order.

F. A person is not relieved of the duty to abate any condition under, or comply with, any requirement of a closure order during an appeal of the order.

G. The Director shall conduct an informal fact finding hearing, in accordance with the Administrative Process Act, §9-6.14:11 of the Code of Virginia, no later than 15 days after the order was issued, or in the case of an expedited hearing, no later than five days after the order was issued.

H. The Director shall affirm, modify, or vacate the closure order in writing, to the person who requested the hearing, no later than five days after the date of the hearing.

§19. Civil Charges.--

A. Civil charges shall be provided for in accordance with §45.1-361.8.C of the Code of Virginia.

B. The Director, after finding any violation of the Act, a regulation promulgated under the Act, or order of the Director or Board, or upon direction from the Board, may recommend a civil charge against a gas, oil or geophysical operator and shall base the recommendation on the Civil Charge Calculation Procedure established by order of the Board.

§20. Surveys and Tests.--

A. Deviation Tests.

1. An inclination survey shall be made on all rotary drilled wells located in accordance with a field rule established by the Board. An inclination survey is not required for wells drilled in accordance with the distance limitations of §45.1-361.17 of the Code of Virginia. The first shot point shall be at a depth not greater than the bottom of the surface casing or, for a well drilled through a coal seam, at a depth not greater than that of the bottom of the coal protection string. Succeeding shot points shall be no more than 1,000 feet apart, or as otherwise ordered by the Director. Inclination surveys conforming to these requirements may be made either during the normal course of drilling or after the well has reached total depth. Survey data shall be certified in writing as being true and correct by the designated agent or person in charge of a permittee's Virginia operations, or the drilling contractor, and shall indicate the resultant lateral deviation as the maximum calculated lateral displacement determined at any inclination survey point in a horizon approved for production, by an order of the Board or a permit approved by the Director, assuming that all displacement occurs in the direction of the nearest boundary of the unit. The resultant lateral deviation shall be recorded on the drilling or completion report filed by the permittee. However, if a directional survey determining the location of the bottom of the hole is filed upon completion of the well, it shall not be necessary to file the inclination survey data.

2. A directional survey shall be made when:

   a. a well is directionally controlled and is thereby intentionally-deflected from vertical;
   b. the resultant lateral deviation of any well, calculated from inclination survey data, is greater than the distance from the center of the surface location of the well bore to the nearest boundary of the area where drilling is allowed in a unit established by the Board; or
   c. a well is drilled as an exception location and a directional survey is ordered by the Board.

3. The Board or the Director, on their own initiative or at the request of a gas or oil owner on a contiguous unit or tract, may require the permittee drilling any well to make a directional survey of the well if there is reasonable cause therefore. Whenever a survey is required by the Board or the Director at the request of a

contiguous owner and the permittee of the well and contiguous owner are unable to agree as to the terms and conditions for making the directional survey, the permittee shall pay for the survey if the bottom hole location is found to be outside of the area approved for drilling, and the contiguous owner shall pay for the survey if the bottom hole location is found to be inside of the area approved for drilling.

4. Directional surveys shall be run from total depth to the base of the surface casing or coal protection string, unless otherwise approved by the Board or the Director. In the event that the proposed or final location of the producing interval or intervals of any well is not in accordance with this section or a Board order, the unit operator shall apply to the Board for an exception to spacing. However, directional surveys to total depth shall not be required in cases where the interval below the latest survey is less than 500 feet, and in such an instance, a projection of the latest survey shall be deemed to satisfy Board requirements.

5. The results of each inclination or directional survey made in accordance with this section shall be filed by the permittee with the first drilling or completion report required by the Department.

B. Flow potential and gas/oil ratio tests: Conventional gas or oil wells.

1. If a gas or oil well appears capable of producing gas or oil, the permittee shall conduct a potential flow test and a gas/oil ratio test within 10 days after the well is completed and capable of producing gas or oil. The permittee shall file the test results, in writing, with the Director. The Director shall hold the test results confidential in accordance with §45.1-361.6 of the Code of Virginia.

2. If a permittee deepens or stimulates a well after the initial potential flow test and gas/oil ratio test have been conducted, when determined to be necessary by the permittee or when requested by the Board, the permittee shall conduct another potential flow test and gas/oil ratio test and, within 30 days after completing the test, file the results, in writing, with the Director.

3. A back-flow method of determining open flow shall be used, such as provided for in the Interstate Oil Compact Commission, "Manual of Back-Pressure Testing of Gas Wells," 1979. However, when a back-flow method is believed not to be feasible, the permittee shall obtain prior approval from the Director, and test the well in accordance with, an alternate method approved by the Director that does not entail excessive physical waste of gas.

C. Testing of coalbed methane gas wells.

1. If a permittee cannot test the potential flow of a coalbed methane gas well by a back-flow method or complete the test within the time period required in

subdivision B.1 of this section, the permittee may request approval from the Director to perform a coalbed methane gas production test. Such a test shall only be made when the water production and the gas flow rates are stabilized for a period of not less than 10 days prior to the test. The test shall be conducted for a minimum of 24 hours in the manner approved by the Director. The permittee shall file the test results, in writing, with the Director. The Director shall hold the test results confidential in accordance with §45.1-361.6 of the Code of Virginia.

D. The Board may, by order and after notice and hearing, require a permittee to complete other tests on any well.

§21. Allowable Production.--

A. The Board, on its own motion, on motion from the Director or on motion from any gas or oil owner, and after notice and hearing, may establish the maximum allowable production rate for any well or number of wells in a pool. The setting of maximum allowable production rates shall be only for the purpose of preventing waste and protecting correlative rights, and not for prorationing production between pools or geographic areas of the Commonwealth. However, no maximum allowable production rate shall be set for a coalbed methane gas well.

B. Proration of gas-lift wells.

1. No flowing or gas-lift oil well may produce with an excessive gas/oil ratio except with prior approval of the Board. Oil wells that are gas-lifted with gas from gas wells shall be prorated in the same manner as high-ratio, naturally flowing oil wells. The gas/oil ratio, for oil wells that are gas-lifted with gas from gas wells, is defined as the total gas output less the total gas input divided by the number of barrels of oil produced. The uneconomic or unreasonable use of gas for gas-lift is prohibited.

§22. Enhanced Recovery.--

The Board may, upon application, notice and hearing, authorize enhanced recovery projects on a case-by-case basis. No enhanced recovery project shall be authorized unless at least 51 percent of all of the gas or oil interests in the area to be covered by the proposed enhanced recovery project consent to the project. The Board may, on a case-by-case basis, establish a minimum percentage greater than 51 percent for any area of the Commonwealth.

§23. Underground Storage of Natural Gas.--

No person may conduct any operation involving storage of natural gas in an underground gas storage field until the Board has adopted an order governing the underground gas storage field.

Appendix C. Microbiology and Biochemistry of SCP and Methanol Formation

Microbiology of Methylotrophs

The very special group of organisms that are capable of oxidizing methane are called methylotrophs. In addition to methane, these organisms are also able to utilize other single carbon compounds, such as methanol, formate, formaldehyde or methylamine, as the sole source of carbon and energy. Organisms that utilize primarily methane are called methanotrophs. Other organisms, such as *Hyphomicrobium* and a few *Pseudomonas* species, cannot use methane, but can utilize other one-carbon compounds and are considered methylotrophs. Obligate methylotrophs utilize only one-carbon compounds, while facultative methylotrophs are able to grow on a wide variety of organic compounds. Energy is derived by oxidation of these substrates to CO_2. Cell growth is facilitated by fixation of formaldehyde by condensation with pentose phosphate (Goldberg, 1985b).

Figure 8 shows the pathway of methane catabolism by methylotrophs (Dalton and Leak, 1985). The usual sequence of methane conversion proceeds to cell biomass and CO_2, with methanol, formaldehyde, and formate as intracellular intermediates.

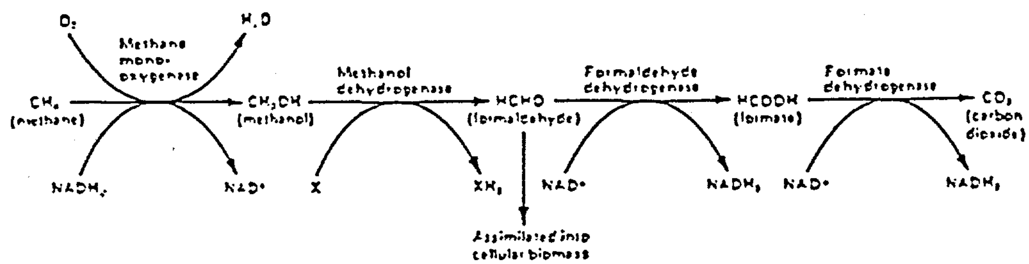

Figure 8. Pathway of Methane Catabolism by Methylotrophs

Two types of methylotrophs have been established on the basis of the type of complex membranous organelles. Type I bacteria have the following properties: formation of intracytoplasmic membranes arranged as bundles of vesicular discs; formation of cysts as resting stages; assimilation of methane and methanol via the ribulose monophosphate (RMP) pathway; the presence of an incomplete tricarboxylic acid (TCA) cycle; and the predominant biosynthesis of C16 fatty acids in the membranes. These organisms lack alpha-ketoglutarate dehydrogenase (Patel, 1984).

By comparison, Type II bacteria have the following characteristics: formation of intracytoplasmic paired membranes around the cell periphery; formation of exospores or lipid cysts as resting stages; assimilation of C1 compounds via the serine pathway; the presence of a complete TCA cycle; and the predominant biosynthesis of C18 fatty acids in the membranes (Colby *et al.*, 1979; Higgins *et al.*, 1981a; Large, 1983).

The methane molecule can only be attacked by methylotrophs by a substitution mechanism. It has been demonstrated that growth on methane is accompanied by the incorporation of an oxygen atom from gaseous oxygen into the molecule to give methanol, as shown in the following reaction (Anthony, 1982; Higgins *et al.*, 1981b):

$$CH_4 + O_2 + 2H^+ \rightarrow H_2O + CH_3OH \xrightarrow{1/2\ O_2} HCHO + 2H^+ \rightarrow HCOOH + 2H^+ \rightarrow CO_2 + 2H^+ \qquad (4)$$

The first reaction is a hydroxylation, catalyzed by a monooxygenase which requires NADH as reductant. Methanol oxidation to formaldehyde is not coupled to NAD^+ reduction but is catalyzed by a methanol dehydrogenase having a novel prosthetic group (PQQ). Formaldehyde oxidation is sometimes coupled to reduction of NAD^+, but it may be oxidized by the methanol dehydrogenase, or by other dye-linked dehydrogenases which may be flavoproteins. When the reductant for methane hydroxylation is NADH (probably always the case), the oxidation of formaldehyde must be coupled to NADH formation. Some bacteria lack a formate dehydrogenase and oxidize formaldehyde to CO_2 by a cyclic variant of their carbon assimilation pathway. The oxidation of formate is always coupled to reduction of NAD^+ and is sometimes the only oxidation step in this sequence to be so.

The enzyme, methane monooxygenase, catalyses the reaction:

$$CH_4 + O_2 + H^+ + NADH \rightarrow NAD^+ + CH_3OH + H_2O \quad (5)$$

This enzyme occurs in both soluble and particulate form. The physical location of the enzyme as a cytoplasmic or extracytoplasmic enzyme has not been determined. Noting that NADH is a substrate, it is generally assumed that the reactions are cytoplasmic. This assumption is also consistent with the fact that they are proton utilizing (Hooper and DiSpirito, 1985). Reducing equivalents from the formaldehyde, formate, and perhaps methanol dehydrogenase reactions are utilized in methane monooxygenase, in the reduction of NAD^+ for biosynthetic reactions, or in electron transport leading to ATP synthesis.

Although the prosthetic group of methanol dehydrogenase is a novel quinone coenzyme (pyrroloquinoline quinone), the enzyme utilizes a soluble cytochrome c as electron acceptor and is therefore a proton-yielding dehydrogenase (Beardmore-Gray *et al.,* 1983). Localization studies have shown that methanol dehydrogenase and the electron acceptors cytochromes CL, and possibly cytochrome CH (Burton *et al.,* 1983; Jones *et al.,* 1982; and Quilter and Jones, 1984), are in the periplasm (Alefounder and Ferguson, 1981; and Kasprzak and Steenkamp, 1983, 1984). Thus, methanol oxidation clearly fits the generalization described in Equation (4) by Hooper and DiSpirito (1985).

Formaldehyde and formate dehydrogenase occur in forms which use either NAD^+ or dyes as electron acceptors (Johnson and Quayle, 1964; and Marison and Wood, 1980). Substrate oxidation is proton yielding and could logically be periplasmic:

$$H_2O + HCHO \rightarrow 2H^+ + 2e^- + HCOOH \quad (6)$$

and

$$HCOOH \rightarrow 2H^+ + 2e^- + CO_2 \quad (7)$$

Depositing cross-membrane translocation of electrons to the proton-utilizing reduction of NAD^+:

$$H^+ + 2e^- + NAD^+ \rightarrow NADH \quad (8)$$

the action of a dehydrogenase located in the periplasm would generate a proton gradient in both reactions. This seems not to be the case with the NAD-linked formaldehyde (Kasprzak and Steenkamp, 1983) and formate (Jones *et al.,* 1982) dehydrogenases; because they are soluble and use NAD, they are probably cytoplasmic. The topological location of the dye-linked enzymes is unknown.

Methane monooxygenase enzyme (MMO), involved in catalyzing the hydroxylation of methane, also catalyses the oxygenation of various hydrocarbons and cyclic, alicyclic and aromatic compounds (Colby and Dalton, 1976; Colby *et al.,* 1977; Dalton, 1980; Dalton and Colby, 1982; Higgins *et al.,* 1981b; and Patel *et al.,* 1979). Thus, it is possible to convert methane to methanol or other short-chain hydrocarbons to their alcohols using whole cell systems. Patel (1984) reported that in using the soluble enzyme methane monooxygenase, extracted from *Methylobacterium* sp. strain CRL-26, it was possible to oxidize methane to methanol, ethane to ethanol, propane to 1-propanol and 2-propanol, butane to 1-butanol and 2-butanol and pentane to 1-pentanol and 2-pentanol, etc.

Mechanism of Methanol Accumulation

There are two basic requirements for the extracellular accumulation of methanol. First, the overall activity of methane monooxygenase must be higher than that of methanol dehydrogenase, i.e., methanol is produced faster than it is consumed *in vivo.* This characteristic is a function of the particular bacterial strain and methylotrophs have been identified that accumulate methanol extracellularly. Conditions might also be found that promote MMO activity and inhibit dehydrogenase activity.

The second requirement is that the methanol produced is not further converted by MMO. The soluble MMO of *Methylococcus capsulatus* (Bath) is very non-specific and utilizes many substrates (Anthony, 1982). Unfortunately, methanol is one of those substrates used by MMO which supports cell growth by yielding NADH through further oxidation. Colby *et al.*, (1977) reported that the MMO in crude soluble extract from *M. capsulatus* (Bath) can oxidize methanol 289 percent faster than it oxidizes methane (85 nmole/(min-mg protein). However, this was the highest rate measured with various amounts of substrates and is not necessarily Vmax. As discussed by Dalton (1980), the K_m for methanol was 0.95 mM, whereas for methane it was 0.16 mM. Under normal assay conditions, and presumably *in vivo*, methanol would not accumulate sufficiently to be competitive with methane. However, in the application of methylotrophs for methanol production, methanol must be accumulated and will necessarily compete with methane in the oxidation by MMO.

Maximum Methanol Yield

Studies with the soluble MMO for *M. capsulatus* (Bath) have demonstrated that NADH is the only effective electron donor for this system (Colby and Dalton, 1976). If formaldehyde oxidation is coupled with reduction of NAD^+, it can be seen from Figure 8 and Equation (5) that for every two moles of methane consumed, one mole has to be completely oxidized to CO_2 to provide enough NADH for the initial oxidation of the two moles of methane to methanol. This means that half the methanol produced must be used for energy or carbon sources. Therefore, without an additional supply of energy, the maximum methanol yield from methane is 50 mole percent, and this can only be accomplished under conditions of low cell growth.

A similar analysis has been used to estimate the amount of carbon assimilated as a percentage of the total carbon utilized, CCE (Leak *et al.*, 1985). Like the methanol yield, CCE for this system must be less than 50 percent. The theoretical prediction of the maximum CCE depends on the nitrogen sources and varied form 42 percent with ammonia to 31.7 percent by using nitrate (Leak *et al.*, 1985). However, there is considerable discrepancy in the literature concerning the growth yields obtainable with methane. In some cases, the cell yields appear to be greater than theoretically possible, assuming that methane oxidation requires NADH as a cofactor (Dalton and Leak, 1985). Whittenbury *et al.* (1970) and Harwood and Pirt (1972) have reported a CCE in excess of 60 percent for Type I methanotrophs. Although it is not known whether these differences were physiological or strain-dependent, it is evident that such high CCE values could only be achieved, theoretically, by assuming that the oxidation of methane to formaldehyde was not consuming energy (Dalton and Leak, 1985).

The recent demonstration that the MMO in *M. capsulatus* (Bath) and *M. trichosporium* OB3b can exist in two forms, dependent on growth conditions (Tonge *et al.*, 1975; Stirling and Dalton, 1979; Scott *et al.*, 1981; Stanley *et al.*, 1983) may yield an explanation for these discrepancies. It has been observed that both *M. capsulatus* (Bath) and *M. trichosporium* OB3b made only particulate MMO in a medium with excess copper. However, a progressive decrease in copper concentration, or an increase in biomass concentration, resulted in the appearance of a soluble form of MMO (Dalton and Leak, 1985). Stanley *et al.* (1983) has demonstrated that the transition between particulate and soluble forms could be altered by changing the concentration of copper in the growth medium.

Leak *et al.* (1985) have demonstrated that the CCE of *M. capsulatus* (Bath) growing on methane in a high-copper medium (particulate MMO) may be up to 35 percent higher than the low-copper medium (soluble MMO). The observed increase in growth efficiency during the transition from soluble to particulate MMO could not be achieved by an increased efficiency of ATP synthesis (Dalton and Leak, 1985; Leak *et al.*, 1985). An increase in growth efficiency of this magnitude must, therefore, arise either from a decreased demand for NADH for methane assimilation or from an increased efficiency of NADH generation during methane dissimilation (Dalton and Leak, 1985).

There is substantial evidence that methanol arising from the oxidation of methane can act as an electron donor for further methane oxidation by the particulate, but not the soluble methane monooxygenase (Leak *et al.*, 1985). Tonge *et al.* (1977) have proposed that methanol dehydrogenase can recycle electrons to the methane monooxygenase without the involvement of NADH as shown in Figure 9. However, both Tonge's concept and the alternative proposal (reduction of NAD via reverse electron transport) have not been fully accepted (Leak *et al.*, 1985).

Although some aspects of energy supply to the particulate methane monooxygenase remain unsolved, it is clear that growth conditions, particularly the concentration of copper in the medium, can have a considerable effect on the yield of methanotrophs growing on methane (Leak *et al.*, 1985). Thus, the yields of both cells and methanol have the potential to exceed 50 percent.

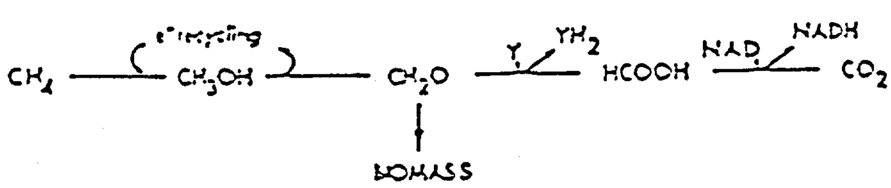

Figure 9. Pathway of Methane Oxidation with Electron Recycling

If the performance of particulate methane monooxygenase is described by the proposed mechanism of Tonge *et al.*, and both particulate and soluble enzymes are available in the cell, the theoretical maximum methanol can be determined. For every mole of methane oxidized, let X represent the methane converted through soluble MMO and Y represent the methane completely oxidized to CO_2 by the soluble route. Thus, this route produces X-Y mole of methanol and generates 2Y mole of NADH, with the requirement of X mole NADH in methane oxidation by MMO. As for the particulate enzyme, 1-X mole of methane will be oxidized by this route. Since methanol is oxidized by methanol dehydrogenase to recycle electrons to methane monooxygenase for methane oxidation, no methanol accumulation is expected in this route. However, two moles of free NADH can be generated for every mole of formaldehyde oxidized to carbon dioxide. Therefore, combining both forms of enzyme, $2*(1+X) + 2Y$ moles of NADH is available to supply the requirement of X mole methane oxidized by the soluble enzyme. Therefore, under the condition of no growth, X is equal to $(2 + 2Y)/3$. The methanol yield by the combination of both forms is X - Y and the theoretical maximum methanol yield is 66.7 percent, which occurs when Y is zero. This means that ideally two-thirds of the methane is oxidized to methanol by soluble MMO and one-third of the methane is oxidized to CO_2 by the particulate enzyme route to provide the NADH for the soluble enzyme.