ALBERTA ENERGY AND UTILITIES BOARD

IN THE MATTER OF the *Alberta Energy and Utilities Board Act*, R.S.A. 2000, c. A-17 (the “EUB Act”), and the regulations made thereunder; and

IN THE MATTER OF section 40(1) of the *Energy Resources Conservation Act*, R.S.A. 2000, c. E-10, (the “ERC Act”) and the regulations made thereunder; and

IN THE MATTER OF Part 2 of Proceeding No. 1457147, Bearspaw Petroleum Ltd. (“Bearspaw”), Carbon Development Partnership (Successor in Interest to Prairie Mines and Royalties Ltd., Formerly Luscar Ltd.) (“CDP”), Devon Canada Corporation (“Devon”), EnCana Corporation (“EnCana”), and Fairborne Energy Ltd. (“Fairborne”), in relation to the Clive, Ewing Lake, Stettler and Wimborne Fields; and

IN THE MATTER OF Alberta Energy and Utilities Board (“EUB” or “Board”) Bulletin 2006-19 (“Bulletin 2006-19”); and

IN THE MATTER OF EUB Notice of Hearing dated June 23, 2006 (“Notice of Hearing”); and

IN THE MATTER OF EUB letter to Legal Counsel dated July 27, 2006 (“Letter to Counsel”).

JOINT SUBMISSION
FILED ON BEHALF OF
CONOCOPHILLIPS CANADA RESOURCES CORP. (“ConocoPhillips Canada”), DEVON CANADA CORPORATION (“Devon”), FAIRBORNE ENERGY LTD. (“Fairborne”), QUICKSILVER RESOURCES CANADA INC. (“Quicksilver”), CANPAR HOLDINGS LTD. (“Canpar”), and CENTRICA CANADA LIMITED (“Centrica”)

August 25, 2006

JOINT SUBMISSION

1. ConocoPhillips Canada, Devon, Fairborne, Quicksilver, Canpar, and Centrica (collectively referred to in this Joint Submission as the “Natural Gas Rights Holders”) are filing this Joint Submission, concurrently with the filing of a separate company specific submissions, in response to the EUB Notice of Hearing and Letter to Counsel. Among other things, the company specific submissions provide particulars of each company’s interest and position in this proceeding and relevant facts and evidence to support the positions taken.

2. In the EUB’s Letter to Counsel, the EUB expressed its expectation that the parties would work together to organize their submissions in an efficient and effective manner to avoid duplication. In response to the EUB’s expectation, the Natural Gas Rights Holders have jointly retained Mr. Matthew J. Mavor, who is President, Petroleum Engineer, of Tesseract Corporation to provide expert evidence.

3. Mr. Mavor was asked to provide his opinion, including a summary of the analysis underlying his opinion, as to the state of natural gas produced from coal seams (commonly referred to as “coalbed methane” or “CBM”) in an undisturbed reservoir and specifically whether or not coalbed methane is coal. Mr. Mavor’s report summarizes his conclusions as follows:

> In Matthew J. Mavor’s opinion, the matters discussed in the preceding sections establish, from his technical and scientific point of view, that natural gas produced from coal seams (often referred to as “coalbed methane” or CBM) is separate and distinct from the coal itself and should be considered in the same manner as natural gas from any other type of natural gas reservoir.
>
> CBM is a natural gas that can be produced from coal seams by industry-wide natural gas drilling and completion techniques. It is generally indistinguishable from natural gas produced from sandstone, siltstone, shale, carbonate, or other rock types in both composition and economic value.
>
> Coal is a solid rock that serves as the container for storage of CBM both before and after the reservoir has been disturbed by man. The majority of the gas-in-place volume is adsorbed within microporosity in the coal rock matrix. The gas is in a dense vapor phase when adsorbed. When released from the adsorbed phase, the gas remains in the vapor phase as its density is reduced during flow through the reservoir into production wells.

> From a reservoir engineering standpoint, CBM shares very similar flow characteristics through coal seams as natural gas flow through other rock types. All generally accepted CBM reservoir models consider the coal as a rock that is the gas storage container and treat the gas as distinct from the coal. The modern fundamental theory for flow through porous media is a applicable to coal and considers flow from higher gas density regions to lower density regions, similar to flow from higher density adsorbed state to the lower density gas in wellbores.[1]

The Mavor report forms part of and is incorporated into this Joint Submission and is attached to this Joint Submission as Attachment "A". Attached to the Mavor report as Appendix I is a Glossary of Relevant Technical Terms. Attached to the Mavor report as Appendix II are Mr. Mavor's qualifications.

Submitted this 25th day of August, 2006.

CONOCOPHILLIPS CANADA RESOURCES CORP., DEVON CANADA CORPORATION, FAIRBORNE ENERGY LTD., QUICKSILVER RESOURCES CANADA INC., CANPAR HOLDINGS LTD., and CENTRICA CANADA LIMITED

Hugh D. Williamson, Q.C.

Counsel for ConocoPhillips Canada and Agent for filing this Joint Submission for Devon Canada Corporation, Fairborne Energy Ltd., Quicksilver Resources Canada Inc., Canpar Holdings Ltd, and Centrica Canada Limited

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[1] Mavor Report, Attachment "A" to this Joint Submission, page 20.

ATTACHMENT “A”

TO THE

JOINT SUBMISSION
FILED ON BEHALF OF
CONOCOPHILLIPS CANADA RESOURCES CORP. (“ConocoPhillips Canada”), DEVON CANADA CORPORATION (“Devon”), FAIRBORNE ENERGY LTD. (“Fairborne”), QUICKSILVER RESOURCES CANADA INC. (“Quicksilver”), CANPAR HOLDINGS LTD. (“Canpar”), and CENTRICA CANADA LIMITED (“Centrica”)

Tesseract Corporation
Petroleum Engineering Technology

Expert Opinion of
Matthew J. Mavor
Concerning
Coalbed Methane Reservoir Behavior

Prepared at the Joint Request of:

ConocoPhillips Canada Resources Corp.
Devon Canada Corporation
Fairborne Energy Ltd.
Quicksilver Resources Canada Inc.
Canpar Holdings Ltd.
Centrica Canada Ltd.

Prepared for:

Alberta Energy and Utilities Board
Proceeding No 1457147
Coalbed Methane (CBM) Review Hearing

Prepared by:

Matthew J. Mavor
Tesseract Corporation

August 23, 2006

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Summary

Mr. Matthew J. Mavor, President, Petroleum Engineer, Tesseract Corporation was retained by the companies listed on the cover of this report to provide his expert opinion on the state of natural gas produced from coal seams (commonly referred to as “coalbed methane” or CBM) in an undisturbed reservoir and specifically whether or not CBM is coal.

Mr. Mavor’s educational and professional experience qualifies him to serve as a technical expert on the subject of natural gas produced from coal seams. He also served as a technical expert in the legal case between Amoco Production Company and the Southern Ute Indian Tribe of Colorado that addressed ownership of natural gas from coal seams. An appendix of this report includes a summary of his experience and publications in reservoir engineering technology.

This report summarizes his opinion followed by sections that describe the basis of his opinion. These sections include the following.

Coalbed Methane Reservoir Systems

The purpose of this section is to clarify important gas storage and flow mechanisms through underground natural gas reservoirs including coal. CBM reservoir behavior is governed by the same physics as for conventional gas reservoirs. Discussions are included concerning the geometry of reservoir systems and important reservoir properties such as porosity and permeability.

Phase Behavior

The purpose of this section is to discuss the states of the fluids (vapor and liquid) in petroleum reservoirs to show that natural gas exists as a vapor in coal natural gas reservoirs under most, if not all, commercial circumstances.

Natural Gas Storage in Coal

The purpose of this section is to discuss the various ways in which gas and water are stored in coal seams, in particular, adsorption that is the dominant storage mechanism under most commercial circumstances.

Coal Gas Well Drilling and Completion Techniques

This section was included to overview the methods used to drill and complete coal gas wells to emphasize that CBM technology is very similar to the technology used for other reservoir types.

Appendix I, Glossary of Relevant Technical Terms

This section was included to clarify the definitions of terms used in this report.

Appendix II, Matthew J. Mavor Professional Experience

This section provides an overview of Mavor’s professional experience and qualifications to serve as an expert witness.

Expert Opinion

Natural gas produced from coal seams is commonly referred to as “coalbed methane” (CBM), “coal gas,” and “coal natural gas”. The term coalbed methane is misleading as natural gas produced from coal seams is commonly a mixture of methane, ethane, propane, minor amounts of heavier hydrocarbons, carbon dioxide, nitrogen, and water vapor. CBM is generally indistinguishable from natural gas produced from sandstone, siltstone, shale, carbonate, or other rock types in both composition and economic value.

CBM and coal are distinct and differ from one another both on the surface after extraction from the ground and in the subsurface before and after disturbance by man.

CBM can be produced from coal seams by industry-wide natural gas drilling and completion techniques. When commercially exploited, CBM is transported on the surface usually as a vapor in pipelines to end users that often burn the gas for an energy source. On the other hand, coal is a rock composed of solid carbonaceous material formed by compaction and thermal alteration of ancient plant material, water inherent to the organic material, and mineral matter (solid inorganic material, such as clay, silt, quartz, calcite, etc.). When commercially exploited, coal is transported usually by truck, train, and/or ship as a solid to end users who often burn the coal as an energy source. Coal and CBM are easily distinguished on the surface; most people can see and pick up pieces of coal; most people cannot easily see or hold CBM in their hands.

In the subsurface, coal and CBM are distinct. Coal is a rock that serves as the container for storage of CBM both before and after the reservoir has been disturbed by man. CBM is a vapor that is compressed or adsorbed in porosity (void space) within the solid rock. CBM may also be dissolved in water (which is present in most, if not all, hydrocarbon reservoirs) contained within larger pore spaces or natural fractures. However, compression and solution storage mechanisms usually contribute little to the total gas-in-place volume. CBM is readily released from and flows through coal due to a reduction in pressure as does natural gas commercially produced from other rock types. CBM differs from the carbonaceous material, inherent moisture, and mineral content of coal, which cannot be separated from the coal in-situ without extraordinary measures such as injection of foreign material such as steam or air (causing in-situ combustion) or mechanical failure of the solid rock itself.

From a reservoir engineering standpoint, CBM shares very similar flow characteristics through coal seams as natural gas flow through other rock types. All generally accepted CBM reservoir models consider the coal as a rock that is the gas storage container and treat the gas as distinct from the coal. The modern fundamental theory for flow through porous media is applicable to coal and considers flow from higher gas density regions to lower gas density regions. The flow of CBM from higher density adsorbed conditions to lower density wellbore conditions is completely analogous. Natural gas depletion of CBM reservoirs and gas reservoirs in other rock types is accompanied by reduction in the average density of the gas and the pressure within the reservoir.

The economic value of coal and CBM are distinct. The economic value of CBM is determined by its composition and heating value; the properties of the coal from which it was extracted are not considered in determining the CBM economic value. The economic value of coal is determined by its composition and heating value; the properties of any CBM which may have been in the coal are not considered in determining the coal economic value.

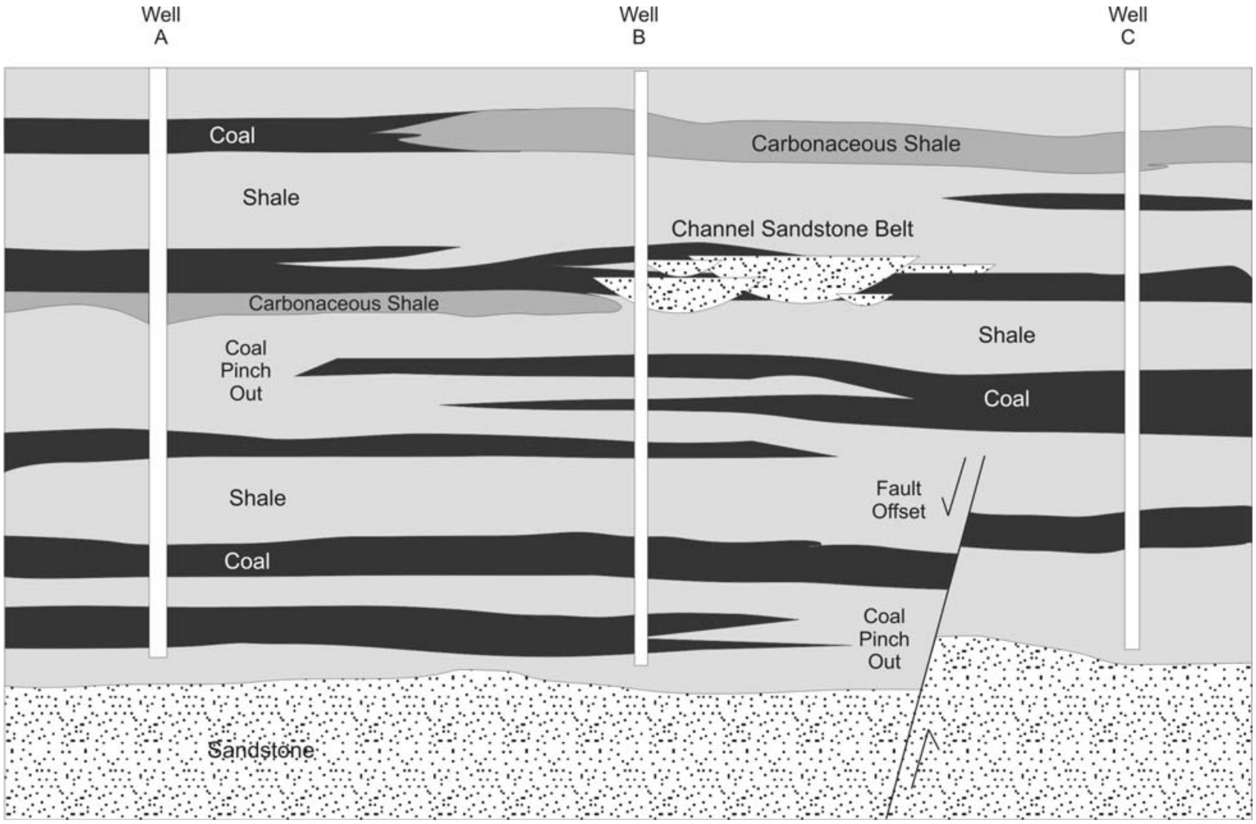
The remainder of this report discusses the behavior of natural gas in coal seams in more detail to outline the reasons behind Mavor’s opinion.

Coalbed Methane Reservoir Systems

Natural gas is commonly produced from underground gas reservoirs from within the porosity (void space) of rock. It is important to understand the storage and flow mechanisms to visualize the production behavior of CBM reservoirs. It is also important to realize that CBM reservoir behavior is governed by the same physical principles that govern flow through other rock types.

Natural gas reservoirs are commonly a three-dimensional system of differing rock types and those associated with coal are not different. CBM reservoir systems can consist of coal seams, carbonaceous shale, sandstone, siltstone, and shale. A possible geometry is illustrated in Figure 1. There may be other rock types present also depending upon the original depositional environment. Natural gas may be contained within all rock types depending upon the degree of trapping that was present over geologic time.

Figure 1. **Coalbed Methane Reservoir Geometry**



The rock types listed above are defined as follows as taken from the generally accepted geologic definitions found in Bates and Jackson.[1] Mavor has found these definitions suitable for his work as well.

Coal: "A readily combustible rock containing more that 50% by weight and more than 70% by volume of carbonaceous material including inherent moisture, formed by compaction and induration of variously altered plant remains similar to those in peat. Differences in the kinds of plant materials (type), in the degree of metamorphism (rank), and in the range of impurity (grade) are characteristic of coal and are used in classification." (Bates and Jackson, page 120.)

Carbonaceous Shale: "A dark gray or black shale with a significant content of carbon in the form of small disseminated particles or flakes; it is commonly associated with coal seams." (Bates and Jackson, page 94.)

Sandstone: “A medium-grained clastic sedimentary rock composed of abundant rounded or angular fragments of sand size set in a fine-grained matrix (silt or clay) and more or less firmly united by cementing material (commonly silica, iron oxide, or calcium carbonate)…” (Bates and Jackson, page 554.)

Siltstone: “An indurated silt having the texture and composition of shale but lacking its fine lamination or fissility….” (Bates and Jackson, page 573.)

Shale: “A fine-grained detrital sedimentary rock, formed by the consolidation (especially by compression) of clay, slit, or mud. It is characterized by finely laminated structure, which imparts a fissility approximately parallel to the bedding, along which the rock breaks readily into thin layers….” (Bates and Jackson, page 583.)

The accumulation of hydrocarbons in a reservoir system requires that there was a source of organic material (plant and/or animal) in sufficient volume that was exposed to sufficient thermal maturation to generate hydrocarbons (commonly referred to as source rock) and a trap to prevent hydrocarbons from migrating out of the reservoir by the time that the reservoir was discovered. The trap prevents migration due to pressure gradients, concentration gradients, and fluid density differences.

The primary source rock for the natural gas in coal seams is generally believed to be organic material sourced from plants that through the process of thermal maturation was converted to coal, hydrocarbons, and non-hydrocarbon materials.[2] The organic material found in coal seams is often thought to be both the source and reservoir rock for the natural gas found therein.[3] However, natural gas created in rock types other than coal can migrate into and be trapped within the coal. It is rarely possible with current technology to identify the precise origin of natural gas presently within a coal gas reservoir. The source could have been within the reservoir of interest, from adjacent source rocks, or from source rocks far removed from the current location of the reservoir. From a production viewpoint, the source of the natural gas is immaterial; the presence of the gas is the important aspect.

Consider the following example of the potential for migration. The organic material that was transformed into coal contained within the Fruitland Formation of the San Juan Basin was deposited approximately 73 million years ago. The generated hydrocarbons had sufficient time to migrate significant distances during the time since creation. The rate of gas flow through a very low permeability (10^{-5} md) rock due to a small (0.01 atmosphere per meter) pressure gradient is 2 cm per year. This is equivalent to a migration distance of 200 km each 10 million years. Diffusion distances can also be significant. A mass transfer rate corresponding to a particle velocity of 0.12 cm/year can be estimated for a coal with a diffusion coefficient of 10^{-7} cm^2/sec. This is equivalent to a migration distance of 12 km each 10 million years. Similar migration distances are possible in Alberta.

The close proximity of reservoir rock and source rock is not unique to coal natural gas reservoirs. The Barnett Shale of Texas is an example of a reservoir where both source rock, a seal rock, and reservoir rock are contained within the same formation.[4] A high proportion (~50%) of the Barnett Shale gas-in-place is stored by adsorption, very similar to the adsorption mechanism in coal seams.

A single reservoir system is one that is hydraulically connected. Hydraulically connected means that fluid can be transported from one region to another within the reservoir or that fluid contained in a region of a reservoir affects the pressure or concentration behavior of other regions of the reservoir during the producing life of the reservoir. The producing life of the reservoir is measured in tens of years. Multiple reservoirs are often found in close vertical and areal proximity. In Figure 1, there may be multiple reservoirs present or, less likely; the entire system may act as a single reservoir. At the time of discovery, one does not know whether the different rock types are hydraulically connected to the same or other rock types.

For example, even if the coal seams penetrated by one well appear to be similar qualitatively and quantitatively to those penetrated by another well, it does not mean that the similar coal seams are hydraulically connected. As another example, coal, carbonaceous shale, and sandstone can form a single reservoir system if all are connected either laterally or vertically. Extraction of the gas from one rock type such as sandstone may cause fluid movement through the nearby rocks as well. It is possible that not all of the rock types in close proximity have traps to store hydrocarbons. For example, Mavor has observed several situations where gas is contained in coal seams but not in adjacent sandstones.

Fluid refers to both vapors and liquids. "A fluid is generally defined as a substance that deforms continuously under the application of a shearing (i.e. tangential) stress no matter how small the shearing stress."[5] "The distinction between a fluid and the remaining possible state of matter (i.e., the solid state) is clear if one compares a fluid as defined above with the behavior of a solid. A solid is a substance that deforms when a shear stress is applied but it does not continue to deform."

Movement of fluids through underground fluid reservoirs containing hydrocarbons and water is governed by basic principles of physics concerning flow through porous media. The most significant properties of these reservoirs are the ability of the rock to contain fluids and the ability of the rock to allow passage of fluids to producing wells. (Muskat 1937[6], page 10.)

There are some unusual fluids referred to as non-Newtonian fluids that can have the properties of both fluids and solids. These are generally liquids containing dispersed solid materials such as clay and polymers that resist deformation like a solid at lower shear rates but act like fluids at greater shear rates. Drilling mud and polymer-based enhanced recovery or hydraulic fracture stimulation gels are examples of non-Newtonian fluids used in the petroleum industry.

Rocks (including marble and coal) and synthetic materials (concrete) can exhibit creep. Creep results in slow, continued time-dependent deformation under continued application of stress.[7] Creep is observed after excavation of hard rock and coal mines as rock deforms into the mine workings. Creep occurs over much longer time periods such as hours and days as opposed to the nearly instantaneous deformation of fluids. Creep is significant over geologic time and commonly believed to have occurred in rock strata.

Natural gas (a mixture of hydrocarbon and inorganic gases) is a fluid in the vapor phase at ordinary (atmospheric) pressure and temperature conditions. (Bates and Jackson, page 418) *CBM is a vapor at commercial CBM underground reservoir conditions. Coal is a rock,* an aggregate of one or more minerals, a body of undifferentiated mineral matter, or of solid organic material that is solid at ordinary surface and subsurface temperature and pressure conditions (Bates and Jackson, page 542.).

An underground hydrocarbon reservoir is a three-dimensional rock system that contains natural gas, hydrocarbon liquids (oil), and water. All hydrocarbon reservoirs contain water to some degree. The proportion of hydrocarbons in the liquid and vapor phases varies from one extreme to the other, i.e., from all liquid to all vapor. Aquifers are underground water reservoirs.

All reservoir rocks contain porosity. Porosity is the portion of the reservoir that is comprised of void space that has the ability to store fluids. Porosity is most commonly defined as the ratio of the void volume to the total bulk volume of the reservoir. (Muskat 1949,[8] page 114.) The size of the pore spaces varies dramatically from micropores that are less than 2 nm in diameter (1 nanometer equals 10^{-9} meters) that are on the order of the size of gas molecules to centimeters. The distribution of the pore sizes in a reservoir is not uniform but varies from the very small pores in coal and clay to natural fractures (discontinuities in the rock fabric) and vugs (voids formed by dissolution of rock material).

Reservoir rock has properties that permit the passage of fluids. Movement of the stored fluids requires that the fluids can flow through the reservoir as the result of density, pressure, and/or concentration gradients. Flow occurs from regions of greater density, pressure, and/or concentration to regions of lesser density, pressure, and/or concentration.

A reservoir is not a static system over geologic time periods of thousands or millions or years. The properties and the location of the rock and any fluids contained therein are changing over this time scale.

The rate of change is sufficiently slow that the system often appears to be static during a time period of 100 years or less.

Formation evaluation is the process of obtaining quantitative estimates of reservoir properties. The two most important CBM reservoir properties are the gas-in-place volume and the natural fracture permeability. This is similar for both conventional and unconventional (including CBM and shale gas) reservoirs where economic value is greater for hydrocarbon reservoirs with greater volumes of gas and/or oil in place and greater absolute permeability.

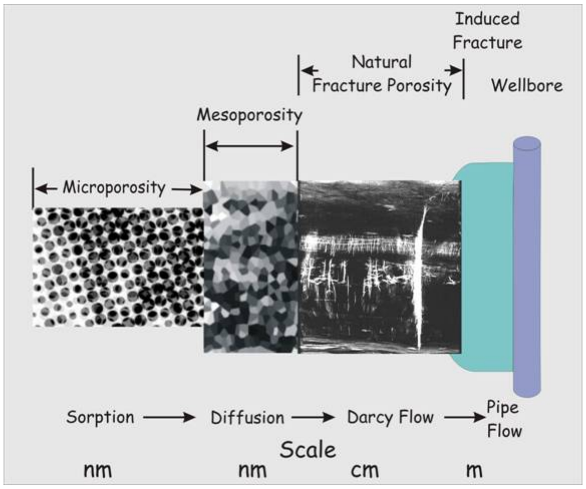
Formation evaluation of coalbed methane reservoirs has been well documented.[9,10] The common approach is to obtain coal core samples for determining gas content, gas storage capacity, gas diffusivity, moisture content, mineral matter content, organic composition, and thermal maturity, among others. Open-hole and cased-hole log data are measured to determine thickness and coal quality estimates using equipment designed for conventional reservoirs. Well tests are conducted to measure gas and water production rates and well pressure as a function of time for estimates of reservoir pressure, permeability, and degree of alteration of the near-well natural fracture system. These estimates are then used in reservoir simulation models to assist with prediction of gas and water production rates from CBM reservoirs.

Much of the CBM formation evaluation technology that has been published concerns the United States due to extensive research funded by the Gas Research Institute (now the Gas Technology Institute). However, the technology has been applied to successfully understand coal seams located in Alberta[11] and Nova Scotia.[12]

Fluid Flow through CBM Reservoirs

Figure 2 illustrates a general schematic of the flow mechanisms in CBM reservoirs. A coal gas reservoir is a dual porosity reservoir system. A dual porosity reservoir consists of two porous media regions: primary and secondary porosity. Primary porosity is generally considered to be matrix rock with properties that are controlled by sedimentary processes and post-depositional lithification (conversion of newly deposited sediment into coherent solid rock involving coalification, cementation, compaction, desiccation, or crystallization, Bates and Jackson, page 363). Secondary porosity can be caused by the development of a natural fracture network or vugs and is usually believed to have been developed subsequent to the primary porosity. The cause of the secondary porosity depends upon the rock type and can be the result of mechanical deformation, coalification, solution, shrinkage, and, for limestone, dolomitization of the original matrix.

Figure 2. **CBM Reservoir Flow Schematic**



Streltsova[13] presented a thorough discussion of fluid flow in dual porosity reservoirs and presented a four tier classification system. Class I, a fractured medium, consists of a reservoir whose primary porosity contains the majority of the fluid storage volume, while the flow conductivity of the combined system is due to the secondary porosity properties. Class II, a purely fractured medium, includes rocks with negligible matrix porosity and permeability. The reservoir exists entirely in the secondary porosity system. Class III, a double porosity medium, includes reservoirs with equal primary and secondary porosity volumes while the flow conductivity is due to the secondary porosity. Class IV, a heterogeneous medium, is a rock system that contains secondary porosity of lower permeability than the primary porosity.

Coal that contains mobile volumes of natural gas falls into the Class I category. The majority of the volume of gas (vapor) stored in the CBM reservoir is contained within porosity developed within the coal matrix rock. Flow to wells occurs within the secondary porosity system. Coal devoid of natural gas would be an aquifer or aquitard and would fall into the Class II category.

The terms secondary porosity system and natural fracture system will be used interchangeably in this document although it is recognized that the secondary porosity system may include natural fractures (cleats), larger scale pores, and vugs.

Prediction and interpretation of transient pressure behavior of dual porosity reservoirs is based upon mathematical models developed by Barenblatt et al.[14] and Warren and Root.[15] These models have been used in well testing applications and reservoir simulation models for both inorganic rocks and coal.

The primary difference between dual porosity reservoir behavior and that of single porosity reservoirs is that single porosity reservoir models assume that the matrix rock has sufficient permeability to allow significant flow into wells. It is probably common that dual porosity systems have been mistaken for single porosity systems. For short production times, dual porosity systems can and will behave as single porosity reservoirs.

CBM Primary Porosity Characteristics

The CBM matrix porosity lies within micropores with a characteristic width of less than 2 nm and mesopores with a characteristic width between 2 and 50 nm. (van Krevelen,[16] page 194) Storage of gas in the small pores is dominated by adsorption due to weak attraction between the vapor molecules and the solid material of the coal as will be discussed in greater detail later. The porosity within the coal matrix is a function of the thermal maturity of the organic material and is in the range of 1% for medium volatile bituminous coal to 22% and greater in subbituminous coal. (van Krevelen, Figure 7.3, p. 197).

The permeability of the coal matrix is generally believed to be in the microdarcy or less range due to the small size of the matrix pores. Coal matrix permeability is often assumed to be negligible; gas flow through the coal matrix is generally believed to be due to diffusion. Water is not assumed to flow by any mechanism through the coal matrix as the water is generally believed to be included inherently in the coal structure. All water produced from CBM reservoirs is believed to flow through the secondary porosity system. The produced water may have been contained in the secondary porosity at the time of discovery of the reservoir of interest or may be produced from adjacent aquifers in other coal seams or other rock types.

For diffusion processes, Fick's Law is used to relate mass transfer to concentration gradients by assuming that the mass flow rate across a surface is proportional to the concentration gradient across the surface, the area of the surface, and the diffusion coefficient of the material through which diffusion is occurring. Mass transport is in the direction of decreasing concentration. Coal diffusivity (diffusion coefficient divided by the square of an average diffusion distance) is determined by analysis of canister desorption data.[17] The units of diffusivity are typically reciprocal seconds (sec^{-1}) while those of the diffusion coefficient are typically square centimeters divided by seconds (cm^2/sec). The diffusivity of commercial CBM reservoirs is commonly the range of 10^{-6} to 10^{-5} sec^{-1}.

Theoretically, diffusion phenomena are discussed in terms of three components: bulk, Knudsen, and surface diffusion.[18] Bulk diffusion is dominated by intermolecular interactions and includes diffusion of one molecular species through a mixture of different molecular species. This is exemplified by dispersion of a drop of iodine in a beaker of water. Knudsen diffusion is dominated by molecule and pore wall interactions. As an example, a molecule in the adsorbed state may acquire sufficient energy through collisions with other molecules to escape the adsorbed state and move into the free gas state. At some point in time, the molecule will be attracted to the pore walls and return to the adsorbed state. The molecule tends to travel in the direction of decreasing concentration during a continued change from the adsorbed to the free gas state. During surface diffusion, mass transfer occurs by movement through the adsorbed state vapor without mass transfer into the free gas state. In practice, diffusion includes all three types and no attempt is made to distinguish between the three processes.

CBM Secondary Porosity Characteristics

The secondary porosity consists of natural fractures with apertures greater than 10 μm and mesopores that have a characteristic dimension greater than 50 nm. The porosity of CBM secondary porosity systems is in the range of $4(10^{-4})$[19] to 6%[20] in Mavor's experience.

The natural fracture system absolute permeability considered for reservoir engineering applications is a bulk property of the rock. Flow description is based upon average flow rates through relatively large volumes of rock containing many pores and fractures and not through individual pores or fractures. The flow rate is proportional to the pressure difference across a specified rock volume. The constant of proportionality is referred to as the absolute permeability if the effects of fluid properties, flow geometry, and relative permeability are removed from the proportionality constant.

The effective permeability to gas and water are determined by analysis of well test data.[21,22] Effective permeability is the product of absolute permeability and the relative permeability to gas and water at the average water saturation within the coal natural fracture system. Well testing technology derived from that developed for conventional reservoirs has been documented for CBM reservoirs in detail. Effective permeability estimates combined with relative permeability data result in absolute permeability estimates.

The absolute permeability is generally greater than 1 md to 3.2 darcies in commercially developed CBM reservoirs in Mavor's experience. Other than the shallow Ft. Union coal of the Powder River Basin of Wyoming, Mavor's observations of the commercial coal absolute permeability range have been from 1 to roughly 96 md.[23]

Fundamentally, Darcy flow of natural gas is characterized by flow through porous media due to density differences. Natural gas flows from regions of greater density to regions of lower density. Al-Hussainy et al.[24] developed the modern real gas potential theory to accurately describe natural gas flow through porous media. Their development of this theory began from a differential equation (Equation 1 of their paper) based upon density gradients and density changes with time due to the fundamental principle of conservation of mass. This real gas potential theory is applicable to CBM reservoirs as well. It is correct to visualize flow of CBM as flow from a greater gas density region (adsorbed gas) to a lower gas density region, a wellbore.

Simplifications are required to recast gas flow theory in terms of pressure. This simplification is commonly used by petroleum engineers as it is easier to measure pressure than density in practical field applications.

Darcy flow is analogous to heat transfer by conduction of energy through solids. In fact, many of the classic heat transfer solutions[25] can be recast from temperature to density or pressure and used for reservoir engineering purposes. These recast equations are applicable to CBM reservoirs also.

The fundamental unit of Darcy flow is the darcy. Katz et al.[26] describe the definition of one Darcy as follows. "A cube of a porous medium 1 cm on edge … will have a permeability of 1 *darcy* if water flows between the front and back faces at a rate … of 1 cu cm/sec under a pressure drop of 1 atm at a temperature of 68 °F where the viscosity is 1 centipoise."

Secondary porosity system absolute permeability and porosity vary as a function of location, pressure within the secondary system, and the composition of gas within the coal matrix. Variations in secondary system porosity cause variations in fluid saturations that in turn cause variations in the relative and effective permeability to gas and water.

Coal secondary porosity permeability is dependent upon net stress in the secondary porosity and changes in adsorbed gas content within the primary porosity.[27,28] During primary production, the net stress upon the coal secondary porosity system increases as the pressure within the secondary porosity decreases which in turn decreases the natural fracture porosity and absolute permeability. This behavior is completely analogous to pore volume compressibility effects in other rock types. As the gas content of the primary porosity system is reduced, the bulk volume of the primary porosity system decreases on the order of 1%. The reduction in the matrix volume is accompanied by an increase in the secondary system porosity which can greatly increase the secondary porosity absolute permeability. Absolute permeability changes from 2.7 to 7.1 times the original permeability have been reported.

Due to the small change in the matrix volume while production is occurring, the change in the rock micro- and mesopore volume is also on the order of 1% or less. As a result, the ability of the coal to store gas is not affected for all practical purposes by the bulk volume changes.

The secondary porosity system of coal generally includes two or more natural fracture sets created at different times.[29,30] Fractures in rock have three basic physical characteristics: 1., fractures have two parallel surfaces that meet at the fracture front; 2., these surfaces are approximately planar, and 3, the relative displacement of originally adjacent points across the fracture is small compared to the fracture length.[31] Cleats are natural fractures in coal. Coal cleat systems are commonly classified into fractures of four types: face cleats, butt cleats, tertiary cleats, and joints. The geometry of cleats is usually specified in terms of frequency (number per centimeter), orientation in the areal sense, dip or the orientation in a vertical sense, and aperture width. Face and butt cleats are often observed to be oriented orthogonally to each other. Tertiary cleats are oriented in directions other than those of face and butt cleats. Joints are larger scale fractures that cut across coal lithotypes (described later) and, in some cases, adjacent interbedded rocks.

Consider the following information that was developed during coal natural fracture studies of Fruitland coal from the San Juan Basin of Colorado and New Mexico. Face and butt cleat fracture description data collected from core samples obtained from several coal gas wells indicated that the majority of the dip angles were between 70 and 90 degrees (i.e., the fractures were near vertical). Cleat height ranged from 1 to 60 cm. Cleat frequency in vitrain lithotypes ranged between 1 and 49 cleats per cm. The aperture of the cleats ranged between 0.01 and 0.3 mm with the majority less than 0.05 cm. The porosity of the natural fracture system (fraction of void space in the fracture to the total bulk volume of the reservoir) was on the order of 0.1 to 3%.

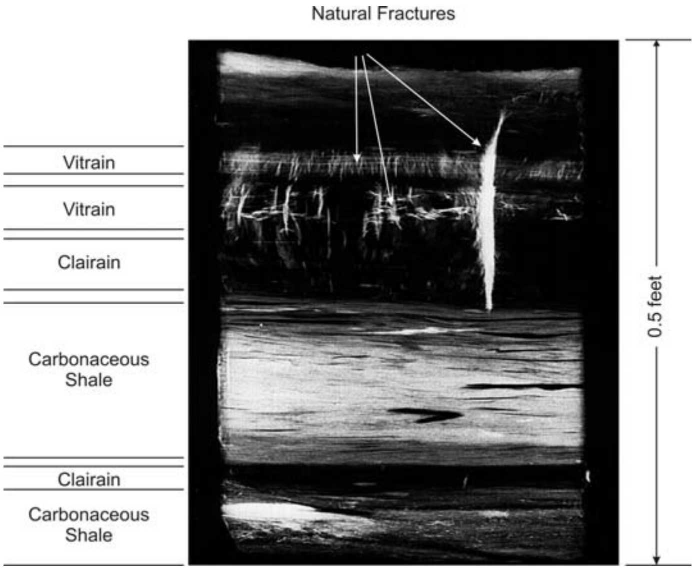
As a result of geometric and lateral continuity relationships, there is commonly a significant face and butt cleat permeability anisotropy in coal reservoirs. As an example, the ratio between absolute permeability in the face and butt cleat orientations was estimated to be 2.8 at the GRI COAL Site research location.[32] The orientation and development of the natural fracture systems strongly influences the directions of fluid flow in the reservoir.

Face and butt cleat frequency is a function of the coal lithotype and the thickness of each of the lithotypes. A coal lithotype is a macroscopically visible band in humic coals that is composed of relatively constant maceral composition. A coal maceral is one of the organic constituents that comprise coal. Macerals in coal are analogous to minerals in non-coal rocks such as sandstone or shale.

Figure 3 illustrates a polished coal block prepared from a coal core obtained from the upper Fruitland coal zone penetrated by the GRI Observation Well #2 at the GRI COAL Site. The lithotype and non-coal interbedding is typical of the Fruitland coal. Natural fractures are evident in the block due to natural calcite filling. While the figure illustrates an excellent example of coal natural fractures, the reservoir from which this block came did not produce commercial gas rates due to reduced natural fracture permeability caused by calcite plugging.

A vitrain lithotype is composed predominantly of the maceral vitrinite. Vitrain will appear as a shiny black band in the block illustrated in Figure 3. Fracture frequency is typically greatest in the vitrain lithotype. Another very common lithotype is clarain that is composed of vitrinite and a greater amount of mineral matter than the vitrain lithotype. Clarain appears to be less shiny than vitrain in coal core samples. Clarain tends to be less fractured than vitrain. The fracture frequency generally increases as the thickness of each lithotype decreases.

Figure 3. **Fruitland Coal Polished Block**



Mathematical Reservoir Models

A variety of mathematical models have been developed to calculate the flow rates of gas and water through CBM reservoirs. In 1989, a general review was presented of 35 different models in existence at that time.[33,34] Some of these models are commercially available to predict the phase behavior and flow through coalbed methane reservoirs. Many of the simulation models were developed for rock types other than coal and in fact it is possible to use conventional reservoir simulation models for CBM reservoir simulation.[21,35]

Modern CBM reservoir simulation software includes features such as 3-D multiple layer reservoir geometry, dual porosity, Darcy flow in the secondary porosity system, adsorption and diffusion of multiple gas species in the primary porosity system, pressure and gas composition dependent absolute permeability, and relative permeability effects.[36] Paul[37] presents information concerning simulation of CBM reservoirs.

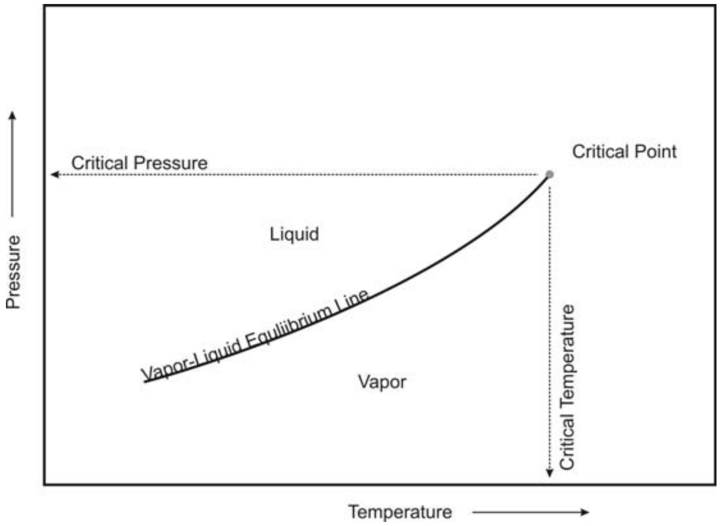
In Mavor's opinion, the most advanced CBM simulation software on the market today is GEM,[38] a 3-D, dual porosity, advanced equation of state model with CBM modifications developed by the Computer Modelling Group (CMG) of Calgary, Alberta. As for most, if not all, of the CBM reservoir models, the GEM software treats the CBM and the organic coal matrix independently; the organic matrix is the "tank" for the storage of CBM. CBM is a vapor that flows through the reservoir from higher pressure to lower pressure regions. GEM was originally developed to model complex phase behavior (such as for gas condensates) and naturally fractured reservoirs found in non-coal rock types. CMG personnel enhanced the ease of application to CBM reservoirs by addition of CBM options, some at Mavor's recommendation.

Phase Behavior

The phase behavior of petroleum fluid systems is an important topic in petroleum reservoir engineering. It is important to understand phase behavior in CBM reservoirs as CBM flow will almost always be in the vapor phase.

Phase behavior is the behavior of vapor, liquid, and solids as a function of pressure, temperature, and composition.[39] The term vapor is often used interchangeably with gas. Liquid generally refers to oil and water. Solids generally include hydrates, asphaltenes, and wax. These phases are generally identified by differences in density with density increasing from vapor to liquid to solid.

Figure 4. Pressure-Temperature Diagram for a Single Component Hydrocarbon



Whitson and Brule discuss the phase behavior of pure (one) component systems, multicomponent petroleum systems, and water in detail in a reference that is widely available to the petroleum industry. Figure 4 illustrates their pressure-temperature diagram for a one component system such as pure methane. Above and to the left of the vapor-liquid equilibrium line, the component behaves as a liquid. At the vapor-liquid line, vapor and liquid phases coexist. Below and to the right of the vapor-liquid line, the component behaves as a vapor. The critical temperature defines the temperature above which liquid and vapor cannot coexist regardless of the pressure. The critical pressure defines the pressure above which liquid and vapor cannot coexist regardless of the temperature. At the critical point, the vapor and liquid properties are identical and the phases cannot be distinguished.

Below the critical temperature, when temperature and pressure conditions change across the vapor-liquid equilibrium line, the change in phase and fluid properties is abrupt. Above the critical pressure and/or temperature, the change in properties is gradual. Depending upon the density, the fluid properties may be referred to as liquid-like at greater density and vapor-like at lesser density.

The term coalbed methane is misleading as natural gas produced from coal seams is commonly a mixture of methane, ethane, propane, carbon dioxide, nitrogen, and water vapor. Heavier hydrocarbons can be present, especially if gas migrated into the coal seams. Generally methane dominates the composition but Mavor has observed gas composition analyses from the Rock Springs Uplift area of the Greater Green River Basin of Wyoming where the carbon dioxide content was near 60%.

The phase behavior of hydrocarbon mixtures is more complicated than for the single component case. However, for CBM compositions where methane dominates the composition, due to methane's low critical temperature of -86.6 Deg Celsius and relatively small proportions of ethane and carbon dioxide, the reservoir fluid will almost always be in the single phase region above the critical temperature. As a result, a liquid hydrocarbon phase will rarely be present in a CBM reservoir, especially in commercial situations.

Natural Gas Storage in Coal

Storage of natural gas in commercial hydrocarbon reservoirs is due to adsorption, compression, and/or solution within the void volume of the various rock types. The rock acts as the tank within where the fluids (vapor and liquid) are stored. The tank model is very appropriate for CBM reservoirs as these reservoirs store the natural gas found at the time of discovery and can be used as storage containers for both previously produced natural gas[40,41] and greenhouse gases such as carbon dioxide.[42,43]

Generally adsorption is found within the microporosity of organic material, compression is found within larger scale porosity within inorganic rocks and the secondary porosity system of coal, and solution is found within liquid hydrocarbons and liquid water. The proportion of storage by any of these processes is controlled by the quantity of organic material present, inorganic rock porosity, secondary system porosity, and the quantity of liquid water and liquid hydrocarbons present as well as the adsorption and solution characteristics of the various fluid components.

In coalbed methane reservoirs, solution in hydrocarbon liquids is generally ignored since these liquids will rarely, if ever, be present. Solution in water while present in CBM reservoirs results in a small proportion of the gas-in-place volume for the following reasons. Dissolved gas is found in the water contained within the secondary porosity. The secondary porosity is generally low, (6% or less for subbituminous coal and 2% or less for bituminous coal), the solution methane-water ratio is low, and the gas saturation within the natural fracture system is often, but not always, low at the time of discovery.

As an example of the relative volume of gas stored by solution in water consider the GRI COAL Site research location in the San Juan Basin of Colorado. The original gas-in-place volume within the Fruitland formation coal was dominated by adsorption and was estimated to be 60.3 Bscf per square mile. The upper limit on natural fracture porosity was believed to be 2%. The solution gas-water ratio at reservoir temperature and pressure was estimated to be 8 scf/STB (standard cubic feet per stock tank barrel). The dissolved gas-in-place volume within the natural fracture system was roughly 0.3 Bscf per square mile or 0.5% of the adsorbed gas-in-place volume. 0.5% is less than the error in adsorption isotherm measurements.[44]

A similar example can be taken from the Mannville (Medicine River) coal of Alberta.[11,27] The in-situ gas-in-place volume per unit area due to adsorption was 3.94 Bscf/mi^2. The porosity and water saturation within the coal natural fracture system before production were 0.002 (0.2%) and 0.909 (90.9%), respectively. The volume of gas stored by compression was 952,000 scf/mi^2 (0.0010 Bscf/mi^2) while the volume stored by solution was 1,278,000 scf/mi^2 (0.0013 Bscf/mi^2). The gas volumes stored by compression and solution were negligible (0.057%) relative to the gas volume stored by adsorption.

Adsorption phenomena are classified into physical and chemical sorption.[45] Physical sorption is the result of van der Waals forces, which are weak intermolecular forces which can be both attractive and repulsive depending upon the intermolecular distance (Ruthven, page 30). Physical adsorption does not result in dissociation of the adsorbed molecular species, is rapid, and is reversible. Chemical sorption is characterized by strong chemical bonds between molecules involving electron transfer due to chemical reactions.[46] Physical bonds can be broken by simple pressure reduction. Much greater energy levels are required to break chemical bonds such as during combustion.

Coal gas reservoir adsorption phenomena are due to physical sorption.[47] During physical sorption, gas molecules experience a net attraction to a solid surface. The effect is amplified in a microporous medium due to the close proximity of gas molecules to the pore walls caused by the very large surface area relative to the micropore volume. The ratio of the surface area to the coal mass is often in the range of several hundred square meters per gram. Because of the attraction, the molecular density (number of molecules per unit volume) of the gases near the pore walls is increased resulting in an increase in the equivalent bulk density of the gas in the adsorbed state. The density of the gas molecules in the adsorbed state is generally believed to be similar the liquid density of the molecules at an atmospheric pressure boiling point. Although the density is similar, the adsorbed gas is in the vapor phase.

Since the temperature of commercial CBM reservoirs is much greater than the critical temperature of methane (-86.6 Deg Celsius), it is not possible to have liquid methane present in the reservoir. Rather than a liquid, it is more accurate to view the adsorbed methane phase as a dense methane gas phase relative to the free methane gas phase stored by compression. The methane does not change phases during production; methane density is reduced upon release from adsorption due to reduction in the pressure within the secondary porosity system.

At the molecular level, adsorption is viewed as a dynamic equilibrium. Vapor molecules are constantly in motion and moving from close proximity to solid surfaces where solid-vapor molecular attraction is significant to more distant regions where the vapor molecules have little net attraction to the solid. At any given moment within a microporous solid such as coal, a majority of the molecules is in close proximity to the pore walls.

Adsorption is not limited to organic material but has been observed in silica gel, activated alumina, activated carbon, illite clay, and crystalline aluminosilicates (zeolites). Significant volumes of gas stored by adsorption is not unique to coal gas reservoirs. Natural gas producing Atrium Shale,[48] Barnett Shale, Devonian Shale,[49] Lewis Shale,[50] and New Albany Shale[51] gas reservoirs also have large volumes of natural gas stored by adsorption. The adsorbed gas is usually found to be contained within organic material based upon adsorption isotherm measurements that Mavor has reviewed.

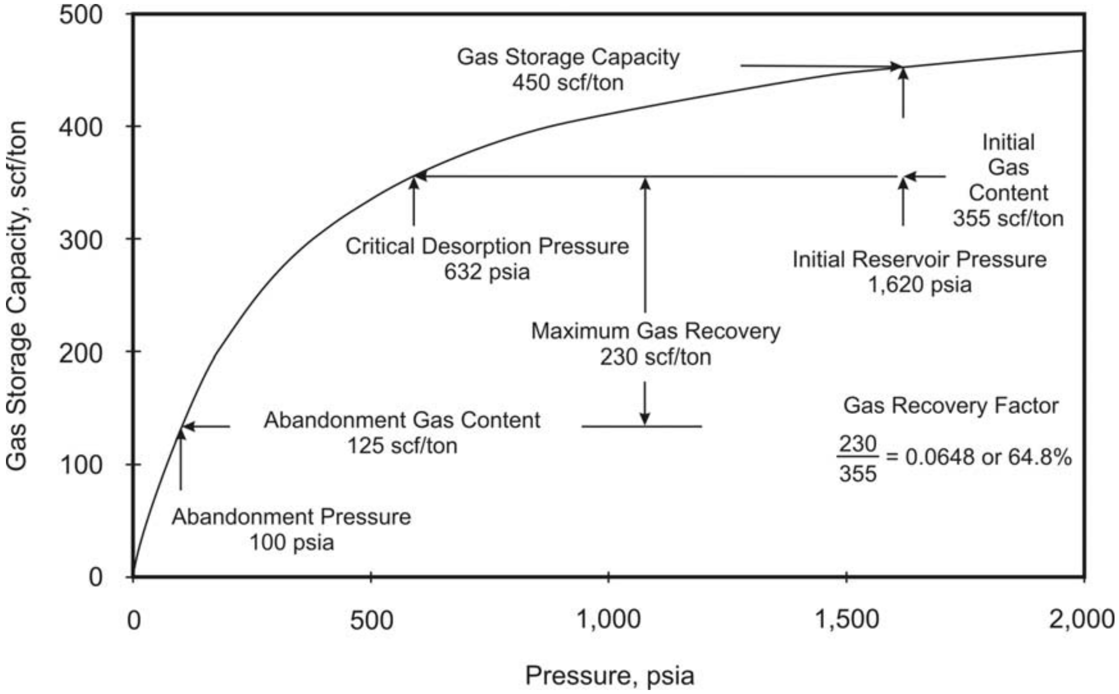
In practice, the CBM production industry does not consider the differences in the density of adsorbed or free gas phases. The volume of gas stored by adsorption is estimated with a Langmuir isotherm that is determined by a commercial coal analysis laboratory at a constant temperature that is usually similar to the reservoir temperature. The only time that the adsorbed gas and free gas density differences are considered is by the laboratory personnel to correct measured isotherm data to a total isotherm.

Figure 5 illustrates an example Langmuir isotherm relationship. The isotherm relationship is very important in coal gas reservoir engineering as it is used to estimate three essential items illustrated in Figure 5. These are

1. the pressure at which gas release (desorption) begins,
2. the amount of gas released as pressure is reduced, and
3. the gas remaining in the reservoir at abandonment.

The gas storage capacity at the initial reservoir pressure is the maximum amount of gas that may be adsorbed in a reservoir. The gas content is the actual gas contained within the rock. This distinction is important, since gas content can be substantially less than gas storage capacity. The correct in-situ gas content is determined by desorption measurements. The critical desorption pressure is the pressure in the coal secondary porosity system at which gas desorption from the rock matrix begins. This pressure is equal to the pressure at which the gas content and storage capacity are equal. The critical desorption pressure can be substantially less than the initial reservoir pressure since the isotherm relationship is relatively “flat” in the higher pressure range.

Figure 5. **Example CBM Langmuir Isotherm Relationship**



Once the pressure drops below the critical desorption pressure, the isotherm relates the gas storage capacity (which is now equal to the gas content) to pressure. The gas recovery factor is one minus the ratio of the remaining gas content to the initial gas content.

The abandonment reservoir pressure can be difficult to determine as it is affected by a combination of reservoir properties and economics. The abandonment pressure is the average pressure of each reservoir when the operator shuts in wells due to gas rates less than minimum economic rates. The average pressure is equal to the pressure at which the reservoir would eventually stabilize and is greater than the pressure in the wells when production ceases. The stabilization pressure is a function of location, permeability, and depth.

Coal Gas Well Drilling & Completion Techniques

Production of CBM away from mining operations has relied upon conventional reservoir drilling and completion methods. This section provides a brief overview of the methods employed by the CBM production operators. The purpose of the section is to make it clear that CBM reservoirs are developed with the same technology used for conventional gas reservoirs.

Drilling and completing a well significantly alters the properties of both the primary and secondary porosity systems adjacent to the well. Solid and liquid materials from the drilling fluids are forced into adjacent rocks. The solid and fluid materials interact with the in-situ fluids and rock. These interactions are almost always detrimental to the ability of a reservoir to produce fluids. Drilling mud commonly reduces the deliverability of a coal gas reservoir to less than half the virgin rock potential within hours of drilling. Completion techniques are designed to overcome the effects of drilling and to increase the connectivity of the well to the reservoir rock through which flow occurs.

Natural gas producing wells completed in CBM reservoirs have utilized a variety of completion techniques including the following.

- Barefoot Open-Hole
- Under Reamed Open-Hole
- Hydraulically Fractured Open-Hole
- Cased, Slotted, No Stimulation Cased, Perforated, No Stimulation
- Cased, Perforated, Hydraulic Fracture Stimulation
- Open-Hole Cavity

With the exception of the cavitated open-hole techniques, all of the completion techniques were developed for other gas reservoirs and were applied to coal gas reservoirs with little modification from the originally developed technology. The cavitated open-hole technique has also been applied to sandstone reservoirs.[52] The most widely used technique is the cased, perforated, fractured technology. In Alberta, Mavor believes that the cased, perforated, hydraulic fracture stimulation completion is the most common. In the San Juan Basin, the open-hole cavity completion was extensively utilized. [53,54] but this technology has not been successful in coal gas reservoirs in other basins in Mavor's knowledge.

Cased Hole, Hydraulic Fracture Completions

Numerous types of hydraulic fracture stimulation treatments have been applied in coal natural gas reservoirs. The following injection and proppant carrying fluids have been used. These fluids were developed for non-coal reservoir applications and have been applied to coal gas reservoirs with minor modifications.

Water
Hydrochloric acid
Hydrofluoric/hydrochloric acid
Vaporized nitrogen
Nitrogen foam
Liquid carbon dioxide
Carbon dioxide foam
Nitrogen, carbon dioxide foam
Linear gelled water
Cross-linked gelled water

Hydraulic fracturing technology became a subject of much debate among coal gas reservoir operators. The techniques that have been in vogue have come full circle starting with water injection without proppant in the early days, progressing to linear gels, foamed water, cross-linked gel systems, nitrogen and carbon dioxide foamed systems, and in the mid-1990s, back to formation water with low and no proppant concentrations.

Today the most common systems are cross-linked gels with lower gel loading and lower temperature breaker systems than in the 1990s[55] and foam stimulations. Technology is being employed to stimulate multiple coal seams limiting the use of completion rigs to reduce costs.[56] In Alberta, operators are stimulating multiple coal seams in a single well with high rate nitrogen injection using coil tubing equipment. Proppant and other additives are often not included but success has also been reported with proppant.[57]

Originally, open-hole completions (especially in the Warrior Basin) were stimulated by injection of water without proppant to artificially fracture the near-well reduced permeability zone and to provide flow paths through the reduced permeability zone. These stimulations were reported to be successful.[58] This technique is still used in the Powder River Basin of Wyoming.

Taurus Exploration began using foamed water and linear gel systems in the Oak Grove Field of the Warrior Basin to stimulate the Mary Lee/Blue Creek coal seams in 1986.[59] The total proppant load was 40,000 pounds of 10/20 or 20/40 mesh sand for each type of treatment. Treating pressure gradients ranged from 0.7 to 1.21 psi/ft. Based upon this experience, high volume water treatments with moderate proppant levels (2 to 4 pounds of proppant per gallon of water) became the standard stimulation.

Use of cross-linked gel systems was found to be very successful at the GRI funded Rock Creek research site.[60] Proppant loads were increased to 10 pounds per gallon. Liquids of this type were used by Amoco Production Co. in the Cedar Hill Field of the San Juan Basin, New Mexico, as well. Other San Juan Basin operators shortly followed suit. A typical San Juan Basin stimulation was based upon designs used in sandstone reservoirs and was similar to the following.

Table 1. Typical San Juan Basin Proppant and Liquid Schedule

Stage	Liquid Volume	Proppant Concentration	Proppant Size
	US gallons	lbm/gal	US Mesh
1	20,000	0	-
2	2,000	1	40/70 or 100
3	8,000	2	40/70 or 100
4	27,000	2 to 10	12/20 or 20/40

The total weight of proppant used was typically 100,000 to 120,000 pounds. The 40/70 mesh or 100 mesh sand was added for fluid loss control. Injection rates of all stages were typically 50 to 60 barrels per minute. All injection was down the casing because of the high rates used. The cross-linked liquid used was generally 30 to 40 Ibm of HPG (hydroxypropylguar) polymer per 1,000 gallons of liquid, cross-linked with a borate ion.[61] Treatments of this type typically required high injection pressure gradients exceeding 1 psi/ft when the coal seams were located within impermeable shale zones.[62] Treating pressures were observed to be less than the overburden gradient when the coal seams were located adjacent to the underlying Picture Cliffs Sandstone due to downward height growth into the sand. The resulting fracture geometry was quite complex containing multiple vertical as well as horizontal components.[63] Warrior Basin cross-linked gel stimulations were similar.[64]

Open-Hole Cavity Completions

The greatest CBM gas production rates have been achieved from San Juan Basin, Fruitland Formation, wells completed with dynamic open-hole techniques commonly known as “open-hole cavity” completions. The dynamic completion procedure consists of gas and water injection into the CBM reservoir followed immediately by a controlled blow out of the well that is repeated over a period of one to two weeks. In many cases the dynamic open-hole wells outperformed the productivity of adjacent wells completed with cased-hydraulic fractured techniques by an order of magnitude. Typically the relative performance ratio between the two completion types was four-fold. Formation damage surrounding the cased-well induced fractures was believed to be the primary cause of the productivity differences between the completion types.

Although Mavor has had direct experience in China and has heard operators discuss the use of open-hole cavity completions in other coal basins, to Mavor’s knowledge, the technology has not been successful in coal formations other than the Fruitland formation.

The common term "open-hole cavity completion" was often used as measured diameters of enlarged wellbores ranged from that of the bit diameter to 4.8 meters (16 feet). The name "dynamic open-hole completion" is a more accurate description of the technique since creation of a cavity was a by-product of the process and not the primary objective. The objective of a dynamic open-hole completion was to effectively link the wellbore with the undamaged natural fracture system of the CBM reservoir. During the process, damaged, near-wellbore coal and other rocks were removed, multidirectional, self-propped fractures were created that intersected pre-existing natural fractures, the near-wellbore aperture of pre-existing natural fractures may have been increased and retained, and the enlarged wellbore may have intersected natural fractures. The wells produced gas and water at rates that were controlled by the normal components of Darcy's Law such as the pressure differential into the enlarged wellbore and the absolute and relative permeability of the reservoir.

An excellent example of the improved gas productivity of open-hole wells relative to that of cased-fractured wells can be taken from the Northeast Blanco Unit of the San Juan Basin. The NEBU #403 R open-hole cavity well produced at gas and water rates in excess of 7,000 Mscf/D and 570 STB/D, respectively, at a bottom-hole pressure of 930 psia. The NEBU #403, located 200 feet from the #403 R, was completed in the same coal gas reservoirs with cased-hole, cross-linked gel fracture stimulation techniques. The maximum productivity of the cased well was 1,100 Mscf/D and 400 STB/D of gas and water, respectively, at a bottom-hole pressure of 800 psia.

Numerous other examples can be selected to illustrate the success of the open-hole completions within a region of the San Juan Basin referred to as the open-hole "fairway." In 1993, in excess of 600 open-hole wells accounted for 73% of the coal gas production from the basin. Over 920 open-hole wells had been drilled at that time accounting for 33% of the San Juan coal gas wells.

San Juan Basin equipment used for open-hole completions was typically as follows. A conventional truck mounted drilling rig was used to drill with natural mud to a depth that was 20 to 50 feet above the top of the reservoir. Casing was set and cemented in place. The open-hole interval was drilled with either a conventional drilling rig or, more often, a modified completion rig. The completion rig was equipped with a power swivel for pipe rotation and reciprocation while circulating and double stack blow-out prevention equipment for pressure control. Four 850 scf/minute air compressors and two dual stage air boosters capable of sustained surface injection pressures of up to 1,500 psig were used for air injection. Triplex pumps normally used for drilling fluid circulation were used to inject small volumes of water. A 6.25-inch hole was commonly drilled below the casing to the total depth of the well using air, air-mist, or formation water as a drilling fluid. Drilling mud was not used to avoid chemical and physical damage to the coal.

The Fruitland Formation open-hole interval was typically 200 to 500 feet in thickness and contained several coal zones and numerous unproductive interbedded shale and shaly sandstone zones. During the completion operations, the interbedded shale within and between the coal zones sometimes swelled and reduced the wellbore diameter or created bridges of rock across the hole. A reduction in the hole diameter increased the risk of sticking the drill string. Stuck pipe problems were reduced by under-reaming the wellbore to a diameter of 10 inches or greater before surging.

Operators replaced existing cased-fractured wells with newly drilled open-hole wells to improve gas deliverability. Recompletion was performed by milling a 8 to 12 foot window through the casing, 100 to 200 feet above the coal zones, and drilling a new hole through the coal zones. Windows were also milled in the coal zones themselves eliminating the need to drill a new hole. The newly exposed coal zones were completed using the dynamic procedures that resulted in similar post-completion production rates as for newly drilled wells. Palmer et al.[65] listed comparisons of unidentified recompleted side-tracked well productivity that ranged between 3.3 and 6 times the original cased-fractured completion productivity.

CBM Drilling Techniques

This section reviews the drilling techniques and completion equipment required to install and operate coal gas reservoir production wells. The technology is the same as that used to drill and operate wells in other reservoir types. While the examples are taken from the San Juan Basin, the Alberta practices are very similar.

Originally, San Juan Basin Fruitland Formation coal gas wells were rotary drilled with mud and completed open hole with under reaming techniques.[66] Failure to maintain hole stability led operators to convert to conventional mud drilling technology after which casing was landed and cemented in place. Communication with the reservoir was achieved by jet perforation followed by hydraulic fracture stimulation.

To maintain stability, conventional wells were drilled with rotary drilling rigs[67] utilizing a fresh water and bentonite (gel) mud system with barite for density control, if necessary. Drilling fluid density was controlled to achieve a mud hydrostatic head 0.1 to 0.5 psi/ft greater than the formation pressure gradient to reduce formation damage.

The size of the drilling rigs ranged from those capable of pulling single 30 foot joints of pipe to those capable of pulling three joints of pipe. The most common rig size was capable of pulling doubles. Location pads were several hundred feet square to accommodate the rig, air compression equipment, generators, mud pumps, the mud tank circulation system, and reserve/flare pits. Often the drilling pad of an existing well drilled to a deeper horizon was used to minimize location preparation costs.

In the San Juan Basin, the surface hole was often drilled with a 12¼-inch bit to 250 feet at which depth surface casing was set. The common surface casing specifications were 8 5/8-inch diameter, 24 lbm/ft, J-55 steel pipe cemented with Class B cement containing 2% CaCl. Wells were commonly drilled to the total depth using a 7 7/8-inch inch bit. The cased-hole depth was generally 100 to 200 feet deeper than the deepest coal to allow installation of a pump below the seams and to provide a sump for produced solid material. The most common production casing utilized was 5½-inch, 23 lbm/ft, K-55 or N-80 steel pipe. Cementing was accomplished by circulating cement spacer and 500 sacks of light weight cement followed by approximately 100 sacks of Class B cement. This type of cased hole well was usually completed by jet perforation and hydraulic fracture stimulation.

The techniques used to drill San Juan Basin open-hole cavity wells were somewhat different. A conventional rotary rig was used to drill the surface and top set portions of the well. The mud system generally was a fresh water, natural mud system. Small concentrations of polymer were sometimes added for viscosity control. The surface hole was drilled with a 12¼-inch bit. Surface casing size was commonly 9 5/8-inch diameter, 38 lbm/ft steel pipe. The top set hole was drilled with an 8¾-inch bit to just above the top of the Fruitland coal seams. Production casing was commonly 7-inch diameter, 23 Ibm/ft, N-80 steel pipe. The casing was set above the coal seams and cemented with Class B cement. The conventional drilling rig was moved off location. A modified completion rig described earlier was moved on to drill through the coal seams and perform an open-hole cavity completion.

Tubing sizes generally varied from an outer diameter of 2 3/8-inches to 5 inches. Packers were generally not installed in the wells. Flowing wells were allowed to produce up the tubing, the tubing-casing annulus, or both. Pumping wells had pumps installed in the tubing. Water was produced up the tubing while gas was produced up the tubing-casing annulus.

Artificial Lift

Artificial lift is very common in the petroleum industry to reduce the bottom hole production pressure for wells that produce liquids. A reduction in the bottom-hole pressure generally results in an increase in the fluid production rates. A desire to reduce the bottom-hole pressure was the reason that some coal natural gas wells had artificial lift systems installed. Many Fruitland Formation coal gas wells produced gas and water without artificial lift.

The most common artificial lift system for coal natural gas production is a sucker rod pump although the progressive cavity pump has been in wide use. Gas lift systems were in use in the San Juan Basin to initially produce high rate water producing wells. Gas lift systems were usually not installed for long term use as it was not possible to decrease bottom-hole pressures to the levels possible with pump systems. Open-hole cavity wells usually had no artificial lift installed although some operators installed gas lift systems.

In pumped wells, gas is allowed to produce up the annulus while water and solids are pumped up the tubing that is usually 2 3/8 or 2 7/8-inches in diameter. Pump placement is often below the lowest perforation to minimize gas locked pump problems. Pump designs may incorporate anti-gas lock systems such as gas anchors. In high rate water wells, blast joints may be placed across perforated intervals to reduce erosion induced tubing failures.

In the San Juan Basin, the most common system in use was a sucker rod system. The Alberta Research Council and Gulf Canada also used this system at the Alberta Research Council Fenn-Big Valley site in Alberta. Pump jack sizes included 180, 300, and 640 peak torque rating with 64 to 200 inch stroke lengths.[68] The prime movers for the pump jacks were often wellhead gas or propane fired unless electricity was available in the field. A Martin split ring type plunger pump placed in the tubing with undersized rings provided solids production tolerance if required by coal fine material production. These type systems were capable of pumping 2,500 STB/D although the most common size was in the 800 STB/D range.

CBM Surface Equipment

CBM surface equipment is designed to separate gas and water production and to handle minor amounts of solid material production. When necessary, gas is treated to remove contaminants. The most common contaminant requiring removal is CO_2; which usually is performed with amine separation equipment. Identical equipment is used for production of natural gas and liquids from non-coal reservoirs.

The northern San Juan Basin CBM reservoirs were over-hydrostatically pressured with surface shut-in pressures that approached 1,500 psig in some instances. The wellhead equipment was usually over-designed to a 3,000-psig working pressure. Although carbon dioxide production was quite significant with carbon dioxide mole fractions ranging from 1 to 15% in the produced gas stream, most operators did not used wellhead equipment designed for carbon dioxide service due to the significant increase in cost.

San Juan Basin surface flow lines were typically 2 or 3-inch schedule 80 steel pipe. The pipe size was selected based upon the water volume to be produced and the distance to the separation facilities.

The common San Juan Basin separator was a standard horizontal or vertical production separator designed to either 1,000 or 1,440 psig working pressure. The separator was operated at the lowest possible pressure above the gas pipeline pressure to reduce the back pressure on the wellhead. Water baths were often necessary to prevent freezing during winter operations.

Depending upon the water disposal system in use it may have been necessary to have up to 2,000 barrels of water storage capacity located at a separation facility. These tanks were typically heated during the winter to prevent freezing.

Compression of the produced gas was often required depending upon the sales line pressure. Typical San Juan Basin multi-well compression facilities consisted of 300 to 500 horsepower, two or three stage, compressors with a 500 psig discharge pressure. Single well installations included 50 to 100 hp compressors installed adjacent to the well. The prime movers were generally fired by natural gas.

The natural gas was eventually compressed into gas pipeline transportation systems that moved the gas to the end user. The gas pipelines companies did not differentiate sales price or acceptability of gas based upon the reservoir type that the gas was produced from.

Surface equipment in other basins is similar although the surface pressure conditions have usually been lower than in the San Juan. As a result, the pressure ratings of the surface equipment are typically lower.

Conclusion

In Matthew J. Mavor's opinion, the matters discussed in the preceding sections establish, from his technical and scientific point of view, that the natural gas produced from coal seams (often referred to as "coalbed methane" or CBM) is separate and distinct from the coal itself and should be considered in the same manner as natural gas from any other type of natural gas reservoir.

CBM is a natural gas that can be produced from coal seams by industry-wide natural gas drilling and completion techniques. It is generally indistinguishable from natural gas produced from sandstone, siltstone, shale, carbonate, or other rock types in both composition and economic value.

Coal is a solid rock that serves as the container for storage of CBM both before and after the reservoir has been disturbed by man. The majority of the gas-in-place volume is adsorbed within microporosity in the coal rock matrix. The gas is in a dense vapor phase when adsorbed. When released from the adsorbed phase, the gas remains in the vapor phase as its density is reduced during flow through the reservoir into production wells.

From a reservoir engineering standpoint, CBM shares very similar flow characteristics through coal seams as natural gas flow through other rock types. All generally accepted CBM reservoir models consider the coal as a rock that is the gas storage container and treat the gas as distinct from the coal. The modern fundamental theory for flow through porous media is applicable to coal and considers flow from higher gas density regions to lower gas density regions, similar to flow from the higher density adsorbed gas state to the lower density gas in wellbores.

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Appendix I

Glossary of Relevant Technical Terms

absolute permeability a measurement of the ability of a rock to transmit fluids when the rock is 100% saturated with a single fluid.

absorption the process of taking up liquids within solids or gases within liquids.

adsorbate an adsorbed substance.

adsorbed gas natural gas that is stored by the process of adsorption.

adsorbent a material with the capability to adsorb.

adsorption the process of bonding gas molecules to a solid upon exposure between the solid and the gas.

anisotropic the condition of having different properties in different directions.

aperture a characteristic dimension of an opening. The characteristic dimension is often width when discussing natural fracture apertures.

aquifer an underground water reservoir that contains sufficient permeability to allow passage of water to wells and springs.

aquitard a confining bed that retards but does not prevent flow of water to or from an adjacent aquifer.

argillaceous largely composed of clay-sized particles or minerals.

asphaltenes any of the solid, amorphous, black to dark brown dissolved or dispersed constituents of crude oils and other bitumens that are soluble in carbon disulfide but insoluble in paraffin naphthas.

augite a common mineral of the clinopyroxene group that occurs as an essential element in many basic igneous and metamorphic rocks.

Bscf billion standard cubic feet, a measure of gas volume at standard pressure and temperature conditions.

butt cleat a secondary natural fracture in coal observed at right angles to the primary fracture (face cleat) orientation commonly terminating in face cleats.

calcite a common rock forming mineral, calcium carbonate, $CaCO_3$.

carbon dioxide the substance CO_2.

carbonaceous shale a dark gray or black shale with a significant content of carbon in the form of small disseminated particles or flakes; it is commonly associated with coal seams.

centipoise the standard oilfield unit for viscosity. Water has a viscosity of 1 centipoise at 68 ^{o}F.

chemical sorption adsorption characterized by chemical bonding, i.e., chemical reactions, between adsorbent and adsorbate. It is often an irreversible process.

clarain a coal lithotype characterized macroscopically by a semi-bright, silky luster and sheet-like irregular fracture. It is distinguished from vitrain by containing fine intercalations of a duller lithotype, durain.

clathrate a term applied to the texture commonly found in leucite-bearing rocks in which leucite crystals are surrounded by tangential augite crystals giving the appearance of a net or sponge.

clay a rock or mineral fragment or a detrital particle of any composition smaller than a very fine silt grain having a diameter less that 1/256 mm. Also a loose, earthy, extremely fine-grained, natural sediment of soft rock composed primarily of clay-size or colloidal particles and characterized by high plasticity and by a considerable content of clay minerals and subordinate amounts of finely-divided quartz, decomposed feldspar, carbonates, ferruginous matter and other impurities.

cleat a natural fracture in coal.

coal A readily combustible rock containing more that 50% by weight and more than 70% by volume of carbonaceous material including inherent moisture, formed by compaction and induration of variously altered plant remains similar to those in peat. Differences in the kinds of plant materials (type), in the degree of metamorphism (rank), and in the range of impurity (grade) are characteristic of coal and are used in classification.

coal seam a stratum or bed of coal.

coalbed methane natural gas produced from coal seams commonly a mixture of methane, ethane, propane, minor amounts of heavier hydrocarbons, carbon dioxide, nitrogen, and water vapor. Also referred to as CBM, coal gas, coalbed gas, coal seam methane, coal seam gas, and coal natural gas.

coalbed synonymous with coal seam.

coalification the alteration or metamorphism of plant material into coal.

compression the state of being compressed. In this document, compression refers to gas storage by temperature and pressure conditions with density computed by the real gas law commonly used by petroleum engineers.

concentration the relative content of a component.

critical desorption pressure the pressure at which gas is released from adsorption during production of coalbed methane from coal seams.

critical point the temperature and pressure condition where vapor and liquid properties are identical and the two phases cannot be distinguished.

critical pressure the pressure above which liquid and vapor cannot coexist regardless of the temperature.

critical temperature the temperature above which liquid and vapor cannot coexist regardless of the pressure.

Darcy flow flow through porous media due to density differences often simplified to pressure differences that can be quantified with Darcy's Law.

darcy the fundamental unit of permeability in oilfield units. A cube of a porous medium 1 cm on edge has a permeability of 1 darcy if water flows between the front and back faces at a rate of 1 cm^3/sec under a pressure drop of 1 atm at a temperature of 68 ^oF where the viscosity is 1 centipoise.

density the mass of a substance per unit volume.

desorption the process of reducing adsorbed gas content by reduction of pressure.

diffusion coefficient a constant of proportionality between diffusion rate per unit area and concentration gradient.

diffusion the process by which matter is transported from one part of a system to another by random molecular motions, generally in the direction of decreasing concentration of a particular component.

diffusivity diffusion coefficient divided by the square of an average diffusion distance.

dolomitization the process by which limestone is wholly or partially converted to dolomite rock or dolomitic limestone by the replacement of the original calcium carbonate (calcite) by magnesium carbonate usually due to contact with magnesium-bearing water or percolating seawater.

dual porosity reservoir a reservoir comprised to two distinct porous media regions generally of dramatically different storage capacity and flow conductivity.

durain a coal lithotype characterized macroscopically by dull matte luster, grey to brownish black color, and granular fracture.

effective permeability the permeability to one flowing phase (oil, gas, or water) in the presence of other phases. Also the product of absolute permeability and relative permeability.

ethane the substance C_2H_6.

face cleats the primary natural fractures often observed in coal.

fissility a general term for the property possessed by some rocks of splitting easily into thin layers across closely spaced, roughly planer, and approximately parallel surfaces, such as bedding planes in shale or cleavage planes in schist.

fluid a substance that deforms continuously under the application of a shearing (tangential) stress no matter how small the shearing stress.

formation volume factor the ratio of the volume of a certain mass of fluid (vapor or liquid) at reservoir conditions to the volume at standard pressure and temperature conditions.

fracture a general term for any break in a rock with little displacement across opposing faces created by mechanical failure induced by stress.

fracture set a collection of natural fractures with similar orientation in a localized area.

free gas natural gas whose properties are controlled by compression.

gas condensate a liquid hydrocarbon phase that condenses from the vapor phase upon reduction in pressure and/or temperature.

gas content the volume of gas at standard pressure and temperature conditions contained within a unit mass of rock.

gas hydrate a solution of gases in crystalline solids called clathrates. Gas molecules occupy the void spaces (cages) within the water-crystal lattice.

gas storage capacity the ability of a rock to store gas generally reported as the volume of gas at standard pressure and temperature conditions per unit mass of rock.

gas synonymous with natural gas or vapor.

gas-in-place the gas volume contained within a reservoir generally usually reported at standard pressure and temperature conditions.

greenhouse gas a generic term for gases that trap heat in the earth's atmosphere by absorption of solar radiation reflected from the earth's surface. Common greenhouse gases are water vapor, carbon dioxide, methane, nitrous oxide, chlorofluorocarbons, and fluorocarbons.

humic coal coal that is derived from peat by the process of humification. Most coal is of this type.

humification the process of the development of humus or humic acids, essentially by slow oxidation.

humus the generally dark, more or less stable part of the organic matter of soil, so well decomposed that the original sources cannot be identified.

hydrate a mineral compound that is produced by hydration or one in which water is part of the chemical composition.

hydraulic fracture a fracture induced in rock through high pressure injection, often by water during a stimulation process.

hydraulically connected reservoir a single reservoir through which fluid can be transported from one region to another or a reservoir in which fluid contained in one region affects the pressure or concentration behavior of other regions during the producing life of the reservoir.

hydrocarbon any gaseous, liquid, or solid organic compound consisting solely of carbon and hydrogen.

illite a generic name for a group a three-layer mica-like clay minerals that are widely distributed in argillaceous sediments.

inherent moisture the fraction of the moisture content of coal that is structurally contained in the material. Also referred to as bed moisture.

in-situ in the natural or original position.

isotherm tabular or graphical data representing changes in properties at constant temperature.

joint a surface or fracture in rock along which there has been very little or no displacement.

Langmuir isotherm the relationship between gas storage capacity and pressure at a constant temperature that is fit with a simple two parameter equation introduced by Irving Langmuir in 1918.

leucite a white or gray mineral of the feldspathoid group, $KAlSi_2O_6$.

limestone a rock composed of more than 50% by weight calcium carbonate primarily in the form of calcite. More specifically a rock composed of 95% calcite and less than 5% dolomite.

liquid a substance of greater density and viscosity than gas that deforms continuously under shearing stress characterized by free movement of the molecules among themselves but without the tendency to separate.

lithification conversion of newly deposited sediment into coherent solid rock involving coalification, cementation, compaction, desiccation, or crystallization.

lithotype a macroscopically visible band in humic coals analyzed by physical characteristics rather than by botanical origin.

maceral one of the organic constituents that comprise a coal mass. Macerals are to coal as minerals are to rock.

matrix in this document, the natural solid rock material of which a reservoir is composed irrespective of composition or particle size.

mesopore a pore within a rock with a characteristic dimension greater than 2 nm and less than or equal to 50 nm.

mesoporosity the void volume within the mesopores of a rock.

methane the substance CH_4.

micropore a pore within a rock with a characteristic dimension less than or equal to 2 nm.

microporosity the void volume within the micropores of a rock.

microporous medium a porous material with void spaces that are largely in the micropore size range.

mineral matter the inorganic material in coal.

molecular density number of molecules per unit volume.

natural gas hydrocarbons that exist as a gas or vapor at ordinary (atmospheric) pressure and temperatures. Methane is the most important but ethane, propane, and others may be present. Common impurities include nitrogen, carbon dioxide, and hydrogen sulfide.

naturally fractured reservoir a reservoir for which the ability to conduct fluids to wells is dominated by flow through natural fractures.

nitrogen the substance N_2.

non-Newtonian fluid a fluid for which viscosity is a function of shear rate or local velocity gradient, generally pastes, slurries, and polymers.

oilfield unit the standard system of units used by petroleum engineers in the United States.

perforation a hole made in casing to allow fluid flow from a reservoir into a wellbore and vice versa.

permeability a measure of the relative ease of fluid flow through porous media due to a pressure gradient.

petroleum a naturally occurring complex mixture of hydrocarbons that can be in the solid, liquid, and gaseous phases.

phase a homogeneous, physically distinct, and possibly mechanically separable portion of matter in an inhomogeneous physical-chemical system.

phase behavior the behavior of vapors, liquids, and solids as a function of pressure, temperature and composition.

physical sorption adsorption caused by weak intermolecular forces and/or electrostatic interactions that does not result in dissociation of the adsorbed molecular species. Usually a rapid and reversible process.

polymer a chemical compound or mixture of compounds formed by polymerization and consisting essentially of repeated structural units.

polymerization a chemical reaction in which two or more small molecules combine to form molecules that contain repeated structural units of the original molecules.

pore a small to minute opening or passageway in rock or soil.

porosity the void volume or interstices within rock whether connected or not, quantified by the ratio of the void volume to the total bulk volume of the system or sample of interest.

porous medium a material having numerous pores or interstices whether connected or not.

primary porosity system in this document, the void volume contained within the solid coal organic material following the Streltsova classification scheme.

primary porosity the porosity contained within the primary porosity system.

propane the substance C_3H_8.

quartz crystalline silica, SiO_2, an important rock forming mineral.

relative permeability the ratio of the effective permeability to a flowing phase (oil, gas, or water) in the presence of other flowing phases to the absolute permeability determined when only one phase is present.

reservoir a subsurface volume of rock with sufficient porosity and permeability to permit the accumulation of crude oil or natural gas under adequate trap conditions.

reservoir engineering a branch of engineering generally involving flow through porous media found in underground hydrocarbon reservoirs. Reservoir engineering tasks typically include quantification of reservoir rock and fluid properties and prediction of oil, gas, and water production rates and associated economic value.

rock an aggregate of one or more minerals, a body of undifferentiated mineral matter, or a body of organic material that is solid at ordinary surface and subsurface temperature and pressure conditions.

sandstone a medium-grained clastic sedimentary rock composed of abundant rounded or angular fragments of sand size set in a fine-grained matrix (silt or clay) and more or less firmly united by cementing material (commonly silica, iron oxide, or calcium carbonate).

scf standard cubic feet, an oilfield unit for gas volume at standard pressure and temperature conditions.

secondary porosity system in this document, the porosity system of substantially greater permeability and lower gas storage capacity than the coal that includes natural fractures and pores beyond the mesopore size range.

shale a fine-grained detrital sedimentary rock, formed by the consolidation (especially by compression) of clay, slit, or mud. It is characterized by finely laminated structure, which imparts fissility approximately parallel to the bedding, along which the rock breaks readily into thin layers.

shear stress the force per unit area that gives rise to tangential stresses (often causing tension) within materials.

silica the mineral SiO_2.

silt A rock fragment or detrital particle smaller than a very fine sand and larger than coarse clay being somewhat rounded by abrasion during transport.

siltstone An indurated silt having the texture and composition of shale but lacking its fine lamination or fissility.

single porosity reservoir a reservoir with sufficient interconnected permeability that the reservoir system acts as though it has one average porosity and permeability although variations in both properties exist.

solid a substance that deforms when a shear stress is applied but it does not continue to deform.

solution the process by which a solid, liquid, or gaseous substance is homogeneously mixed with a liquid or sometimes a gas or solid.

sorbed gas synonymous with adsorbed gas.

sorption synonymous with adsorption.

source rock sedimentary rock in which organic material under pressure, heat, and time was transformed to liquid or gaseous hydrocarbons. Source rock is generally shale or limestone.

standard pressure absolute pressure commonly taken to be 101.325 kPa, 14.696 psia, or 14.73 psia that may be set by regulatory bodies for the purpose of gas volume determination.

standard temperature a temperature commonly taken to be 60 ^oF (15.6 ^oC) that may be set by regulatory bodies for the purpose of gas volume determination.

STB stock tank barrel, the standard liquid volume in oilfield units.

tertiary cleat a natural fracture in coal generally observed at a different orientation than face or butt cleats commonly terminating in face or butt cleats.

thermal maturation synonymous with thermal metamorphism, a type of metamorphism resulting in chemical reconstitution controlled by a temperature increase and influenced to a lesser extent by the confining pressure without a requirement of simultaneous deformation.

van der Waals forces relatively weak intermolecular forces that are operative between neutral atoms and molecules that arise because of the electric polarization induced in each of the particles by the presence of other particles. These forces were originally proposed by Johannes D. van der Waals, a Dutch physicist circa 1923.

vapor a substance in the gaseous state as distinguished from the liquid or solid state.

viscosity the constant of proportionality between the shear force per unit area and the local fluid velocity gradient as defined by Newton’s law of viscosity.

vitrain a coal lithotype characterized macroscopically by brilliant vitreous luster, black color, and cubic cleavage with conchoidal fracture.

vug a small cavity in a vein or rock.

water the substance H_2O in some cases including dissolved substances.

wax a solid, noncrystalline hydrocarbon of mineral origin such as paraffin wax composed of the fatty acid esters of the heavier hydrocarbons.

zeolite a generic term for a large group of white or colorless hydrous aluminosilicates that are analogous in composition to the feldspars with sodium, calcium, and potassium as their chief metals. Zeolite is often used as an industrial adsorbent.

Appendix II

Matthew J. Mavor Professional Experience

Related Professional Expertise

I believe that I am qualified to provide this opinion based upon my education and professional experience. I received a Bachelor of Science degree (1977) and a Master of Science degree (1978) in petroleum engineering from Stanford University. I have been employed in the petroleum industry continuously since receiving these degrees. Much of my professional experience has been in application of reservoir engineering principles to quantify the properties of underground hydrocarbon and water reservoirs and to predict the production rates of oil, gas, and water from said reservoirs considering both physical principles and economic return.

I was hired by Resource Enterprises Inc. (REI) of Salt Lake City, Utah, in November 1988 to manage and perform research concerning coal natural gas reservoir properties and completion techniques for a multimillion dollar research effort funded by the Gas Research Institute (GRI - now Gas Technology Institute - GTI). REI was also awarded a second GRI project to improve the methodology for determining total gas content of CBM reservoirs. I managed and performed research for both of these projects until 1993 when I created Tesseract Corporation to provide independent petroleum engineering consulting services. I continued to provide support to REI until both of the GRI research projects were completed in 1995 and 1996.

REI was retained by Amoco Production Company to provide my services as an expert witness in the legal case between Amoco and the Southern Ute Indian Tribe of Colorado that addressed the ownership of natural gas produced from coal seams.

In January of 1996, GRI contracted Tesseract to investigate methods to indirectly identify sweet spots (regions of greater permeability) in coal seams located in U.S. basins. This project was expanded to include research to determine the reservoir properties of the Lewis Shale of the San Juan Basin in New Mexico. This project was completed in June 2001.

In March 1998, the Alberta Research Council (ARC) of Edmonton, Alberta, contracted Tesseract to provide my coal natural gas expertise and to develop new technology for storing carbon dioxide and other atmospheric pollutants in coal seams of Alberta. I am still contracted by ARC for this project and for providing this expertise in Japan at the time of this report.

Between May 1998 and March 2000, Tesseract Corporation was contracted by TICORA Geosciences of Arvada, Colorado, to provide my CBM expertise to their GRI research effort to investigate the properties of Powder River Basin, Wyoming, CBM reservoir properties.

Between January 2003 and June 2004, Tesseract received a second contract from TICORA Geosciences of Arvada, Colorado, to provide technical expertise to their multimillion dollar GTI research effort to expand coalbed methane technology to frontier basins and to develop new adsorption isotherm technology.

In addition to the aforementioned research projects, Tesseract has been contracted by over 72 companies to provide my CBM, shale gas reservoir, and petroleum engineering expertise in the 13 years of its existence. This experience has resulted in my direct involvement in the evaluation and development of CBM reservoirs in the United States, Canada, China, Australia, and Japan.

During my professional career, I have been the co-inventor for two United States patents and one Australian patent relating to storage of carbon dioxide in and enhanced recovery of CBM from coal seams. I have also authored or coauthored 36 technical papers on CBM and reservoir engineering topics, and 27 Gas Research Institute publications. My resume and publication list follow.

Tesseract Corporation

Petroleum Engineering Technology

Matt Mavor
Petroleum Engineer

Education:

B.S. Petroleum Engineering (with Distinction), Stanford University, 1977
M.S. Petroleum Engineering, Stanford University, 1978

Professional Associations:

Society of Petroleum Engineers, Society of Professional Well Log Analysts,
Society of Core Analysts, American Association of Petroleum Geologists

Professional Experience:

1993-Present President, Petroleum Engineer, Tesseract Corporation.

Responsible for corporate management, management of gas exploration and production companies, and technical execution and management of research and technical service contracts. Tesseract's technical expertise is in the disciplines of formation evaluation (core, log, and well test analysis), reservoir engineering and simulation, and completion engineering for many types of reservoir rocks and fluid properties, especially unconventional reservoirs. Primary clients are independent petroleum producers.

1988-1993 Manager, Energy Services, Resource Enterprises, Inc.

Responsible for management and technical execution of research and technical contracts in the disciplines of geology, formation evaluation, completion engineering, and reservoir engineering for coal natural gas reservoirs. Functioned as the project manager and Principal Investigator for the Gas Research Institute Western Cretaceous Coal Seam Project. Other clients included US major and independent petroleum producers, mining companies, and the U.S. Department of Energy.

1985-1988 Manager, Formation Evaluation, Scientific Software-Intercomp, Inc.

Responsible for proposal, pricing, performance, and profit & loss of consulting projects in the technologies of geology, core data analysis, well log analysis, well test analysis, completion design, and reservoir engineering for reservoirs of all lithologies and fluid types. Clients included international and domestic oil and gas producers.

1984-1985 Senior Formation Evaluation Specialist, Chevron Overseas Petroleum, Inc.

Responsible for the evaluation of internationally located hydrocarbon reservoirs for the purpose of reservoir description and reserves determination.

1982-1984 Senior Drilling and Production Engineer, Chevron USA, Inc.

Responsible for design and supervision of offshore completion and drilling operations in the U.S. Gulf Coast area.

1978-1982 Research Engineer, Chevron Oil Field Research Company.

Responsible for development, application, and training in the area of well test design, supervision, and analysis.

United States Patents

Gunter, W.D., Mavor, M.J., Law, D.H.-S.: *Process for Recovering Methane and/or Sequestering Fluid*, United States Patent No. 6,412,559 G1 (July 2, 2002).

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Australian Patent

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