Enhanced coal bed methane recovery using CO_2 Injection

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Approved

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CERTIFICATE

This is to certify that the work contained in this thesis titled "**Enhanced coal bed methane recovery using CO_2 Injection**" has been carried out by **Manisha Dhapola R040206030 (B.tech APE II)**, under our supervision and has not been submitted elsewhere for a degree.

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ABSTRACT

The ECBM process involves drilling a set of wells into the coal seam, one for injection of the oxidants and the other well at some distance away to bring the product gas to the surface.

Enhanced recovery of methane is possible using two methods:

- The first method, the partial pressure of methane is reduced by injecting an inert gas, such as helium or a gas that adsorbs more weakly than methane in coal, such as nitrogen (N_2), into the coal seams and thus maintaining the total pressure. Since the partial pressure of methane is reduced, it desorbs to achieve partial pressure equilibrium. Since helium is more expensive and scarce to obtain, nitrogen, which is cheap and abundant, is used in this process. This process is also referred to as methane stripping.

- The second method uses the injection of carbon dioxide (CO2) to displace methane as of coal seams. Carbon dioxide is more strongly adsorbed on coals than both nitrogen and methane in coals and so it displaces methane by better adsorption. As an added benefit, this process also helps sustain the total system pressure.

Enhanced coal bed methane recovery using CO_2 Injection is a method of producing additional coal bed methane as of a source rock, similar to enhanced oil recovery applied to oil fields. Carbon dioxide (CO_2) injected into a bituminous coal bed would occupy pore space and also adsorb onto the carbon in the coal at approximately twice the rate of methane (CH_4), allowing for potential enhanced gas recovery.

Carbon sequestration is a geoengineering technique for long-term storage of carbon dioxide or other forms of carbon to mitigate global warming. Carbon dioxide is usually captured from the atmosphere through biological, chemical or physical processes. It has been proposed as a way to mitigate accumulation of greenhouse gases in the atmosphere, which are released by burning fossil fuels.

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Chapter 1

Introduction

Methane burns more cleanly than any other fossil fuel. Methane is cheap, and it comes as of domestic sources; a U.S. source of about 800 trillion cubic feet (Tcf) of methane has been discovered in coal beds. This significant energy source has been converted as of a centuries old mining hazard into an environmentally friendly fuel.

Production of coal bed methane (CBM) in a short time has become an important industry, providing an abundant, clean-burning fuel in an age when concerns about pollution and fuel shortages pre occupy the thoughts of many Americans. Other than in the U.S.A., CBM is being produced in Queensland, Australia and the United Kingdom. Pilot projects are underway in China and India. Test or pilot programs are underway in approximately 15 other countries.

Use of CBM might improve the environments of Eastern Europe and China. In the United States, it might be an alternative fuel for automotive vehicles or the clean fuel of the future in power plants.

Consider that the use of CBM might fulfill national goals, such as the following:

- Provide a clean-burning fuel.
- Increase substantially the natural gas reserve base.
- Improve safety of coal mining.
- Decrease methane vented to the atmosphere as of coal mines that might affect global warming.
- Provide a means to use an abundant coal resource that is often too deep to mine.

The process may be applicable wherever coal is found. Much potential exists internationally. Spain, France, Poland, Australia, Canada, the Peoples Republic of China, Great Britain, Germany, Zimbabwe, and Russia are a few of the countries that have undertaken projects after the initial success in the United States. Over 60 countries have substantial coal reserves, and most of them are interested in recovering the methane. In Eastern Europe, for example, coal may be the only natural energy resource of a country. In this region, CBM holds the intriguing potential to help supply energy needs for revitalizing industries—and in a manner that improves air quality. The same intriguing potential exists in other developing countries where industry and environment suffer parallel fates.

CBM, an emerging industry, developed over a span of 5 years after 5 years of research and pilot projects. Initial process improvements came rapidly to bolster its success where these innovations improved production, economics, reservoir management, and drilling. The primary catalyst for CBM development was possibly a federal tax credit that overcame the inertia of starting a new industry.

Employed in the coalfields have been oilfield techniques, sometimes modified and improved. In many ways the CBM process has merged technologies as of the oil industry and the coal industry. For example, during the preceding generation, methane was produced for local use as of wells drilled into coals, but it took the fracturing of those coals and their dewatering, along with other oilfield technology, to increase production rates to commercial levels. Research generated by the activity delved into coal properties and associated phenomena on a scale not undertaken before for coal.

Future technical advancements may turn properties that are now marginal into successful commercial ventures. Breakthroughs may make production of the methane of deep coals profitable because a vast resource lies at depths heretofore not considered for mining or methane recovery—exciting challenges for industry.

1.1 The CBM Resource

Methane has been traditionally extracted as of coals to reduce mining hazards, but the gas was vented to the atmosphere with large fans in the mines. Some methane was tapped as of coal by vertical wells earlier in the last century and the gas was used locally. For example, CBM was produced commercially as of the Mulky coal seam in south-eastern Kansas as of 1920 into the Great Depression.

Low explosive limits of methane in the air have made it necessary to vent great volumes of the gas as of gassy coals of mines before working in the mines. It is estimated that a volume of 250 million cubic feet per day (MMcf/D) of methane was vented as of U.S. coal mines directly into the atmosphere in the early 1980s. This increased to 300 MMcf/D in 1990.15 Venting has occurred in U.S. coal mines since the 19th Century.16 The necessity of sweeping out the methane with large amounts of air is apparent upon considering that explosive limits of methane in air are 5–15%, by volume. In Alabama, multiple fans requiring as much as 14,000 hp have the capacity to sweep as of mines up to 20 MMcf/D of methane with 3.4 MMcf/min of air, venting directly to the atmosphere. As mining extends deeper, more methane must be removed further, and the costs compound. According to the EPA's Coal bed Methane Outreach Program (CMOP), emissions decreased by 30% as of 1990 to 2001 because of:

(1) The increased consumption of CH_4 collected by mine degasification systems and
(2) A shift toward surface mining.

The venting procedure as a contributor to the greenhouse effect has received mounting environmental concerns. It is estimated that methane as of all sources, not just coal, contributed 9% of the detrimental effects of global warming during the year 2001, although the methane has a much shorter longevity than carbon dioxide. About 10% of the methane going into the atmosphere can be attributed to coal mines.

Development of the commercial CBM process is a positive step for the environment worldwide. However, environmental effects of vented methane were not the driving force for developing the CBM process. Rather, the initial incentive was to improve mine safety. As the process was improved, it became apparent that a substantial commercial value existed either in pipeline sales or in supplying on-site energy needs. This realization provided the final incentive for widespread development in mines as well as in vertical boreholes not associated with mines. Table 1 summarizes significant events in the commercial development of CBM.

Table 1—Highlights of Coal bed Methane Development

1920–1933	Wells drilled into S.E. Kansas coalbeds inadvertently and methane produced.
1928	Rice suggested vertical wells to drain CH_4 from coalseams before mining.[20]
1931	Coalbed CH_4 found upon abandoning conventional gas well in West Virginia. Produced 212 MMcf until 1968.
1954	First coalbed methane well fractured by Halliburton experimental project with USBM.
1973	USBM funded project to improve degasification preceding mining. Studied fracturing in PA, VA, WV, OH, and IL mines.
1978	DOE, Gas Research Institute (GRI) undertook joint project in Warrior basin of Alabama; studied response of coalseams to fracturing. Evaluated CH_4 commercial possibilities.
1980	Federal tax credit established for coalbed methane.
1983	Gas Research Institute and U.S. Steel began Rock Creek Research Project.
1985	Regional coalbed methane information centers established by GRI near Warrior and San Juan basins.
1992	1.5 Bcf/D production of coalbed methane from 5,500 wells.
1994	U.S. EPA's Coalbed Methane Outreach Program (CMOP) initiated.
1995	The first GRI Regional Coalbed Methane Center to open in Tuscaloosa, AL was closed.
2000	3.7 Bcf/D production of coalbed methane from 13,986 wells.
2003	The Regional Information Center in Denver (the final one in operation) established by GRI closed.

Chapter 2: Geological Influences on Coal

2.1 Formation of Coals

Coal begins when plants are deposited in swamps, then submerged rapidly enough to limit oxidation but to allow microbial decomposition. Shallow waters of a constant depth, such as created between fluvial systems in plains along the coast of seaways or behind coastal barriers, allow enough plant mass and it's covering of sediment to accumulate as undisturbed peat.

The peatification process continues as the decomposing plants are progressively covered with sediments, physical processes act to compress, and biochemical processes alter the remains in an environment of warm temperatures and abundant rainfall. When the organic mass becomes deeply buried, coalification transforms it as a function of pressure, temperature, and time. Of these parameters, temperature is the most important in the geochemical reactions that occur.

As temperature and time progressively change the molecular structure of coals, a point is reached where thermogenic methane is evolved in large volumes, micro pores develop to store extraordinary amounts of methane per unit of coal, and fractures permeate the coal to transport the excess methane. Thus, methane is generated to be stored and dissipated over geologic time.

2.1.1 Stratigraphic Periods

The stratigraphic periods for coal formation are given in Fig. 2.1. It should be noted that the Carboniferous period generated most of the coals. Younger coals in the Cretaceous, Paleocene, and Eocene periods are of lower rank or maturity unless a localized heat source occurred to accelerate the normal metamorphism or burial history was altered by tectonic action. Lignite exists in various parts of the world as of younger Miocene and Pliocene deposits; current peat deposits began during the Quaternary era.

2.1.2 Tertiary Coals of Western United States

Shallow coals in the Powder River basin of northern Wyoming and south-eastern Montana were formed during Palaeocene and Eocene periods. The lignite to sub bituminous coals has the thickest individual seams in the country, exceeding 100 ft.

In the Paleocene period, the Cretaceous Seaway regressed, leaving an extensive coastal plain cut by stream channels all along its western coast (Fig. 2.2). The sea ran as of what is now eastern Alaska to the Gulf of Mexico. During this time, fluvial-channel and fluvial-lake sediments accumulated to form the Fort Union formation in the Powder River basin, where large peat swamps developed between the meandering stream channels.

Into the Eocene period, the deposition was similar so that the interface of the sediments may be hard to distinguish. The Wasatch formation contains the Eocene coals of the Powder River basin. Especially noteworthy is the 200-ft-thick Lake de Smet coal bed.

2.1.3 Cretaceous Coals of Western United States

The western U.S. coals of current interest were deposited primarily in the Cretaceous Age about 90–120 million years ago (m.y.a.) at the western coast of the Cretaceous Seaway. This sea ran approximately parallel to the present Continental Divide. As Fasset points out, the Fruitland formation of the San Juan basin, the most productive of all U.S. coal basins, resulted as of the last regression of that coast (see Fig. 2.2).

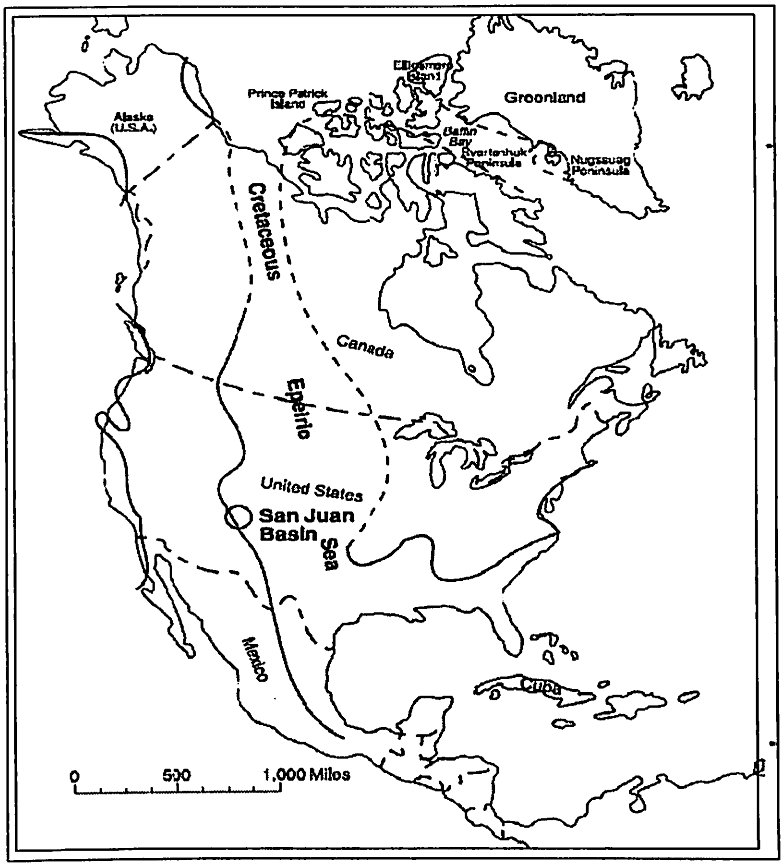
The coals of the Fruitland formation of the San Juan basin have the most prolific coal bed methane (CBM) production in the world. The sediments of the Fruitland accumulated during the Cretaceous Age in a manner similar to the other coal basins along the Cretaceous Seaway.

The fluvial system in the delta flowed north-eastward into the sea, leaving fluvial-channel sediments that now constitute the sandstone formations pointing like fingers north-eastward in the Fruitland. Peat swamps formed within the fluvial system and rested upon a base of Pictured Cliffs sandstone deposited as of the regressed seaway. Therefore, the coals intertongue with the Pictured Cliffs sands at the present north-eastern boundary of the basin.

Fig. 2.1—Cretaceous Seaway and western coals

Age	Millions of Years: Mean Age of Coals	Duration of Period	Stratigraphic Period			Principal Species of Animals
	—	—		Quarternary	Holocene	Mammalia, Man Insects
	<1	1			Pleistocene	
-1-						
	2	11			Pliocene	Domination of Mammalia Fishes, Birds.
-12-						
	15	11			*Miocene*	
-23-	28	12	Cenozoic	*Tertiary*	Oligocene	
-35-						
-55-	60	20			*Eocene*	
		15			*Paleocene*	
-70-						
	120	65		*Cretaceous*	Upper Lower (Weald)	Dwindling of Ammonites, Belemnites and Sauria; origin of Mammamlia and Birds.
-135-						
	160	45	Mesozoic	Jurrassic	Upper Middle Lower	Domination of Reptilia and Amphibia, (Dinosauria and Ichthyosauria). Mollusca (Ammonites and Belemnites)
-180-						
	200	40		Triassic	Upper Middle Lower	Crustacea, First Reptilia and Mammalia
-220-						
	245	50		*Permian*		Protozoa, Fishes, Mollusca, Arthropoda (Insects). First Amphibia.
-270-						
		50			*Upper carbonifer.*	
	300			*Carboniferous*		
-320			Palaeozoic			
		30			*Lower carbonifer.*	
-350-	380	50		Devonian		Domination of Coelentrata, Mollusca.
-400-						
		90		Silurian		Protozoa, First Fishes.
-490-		110		Cambian		Protozoa, Coelentrata, First Mollusca.
-600-						
		>1,000	Proterozoic	Algonkian		
				Archaean		

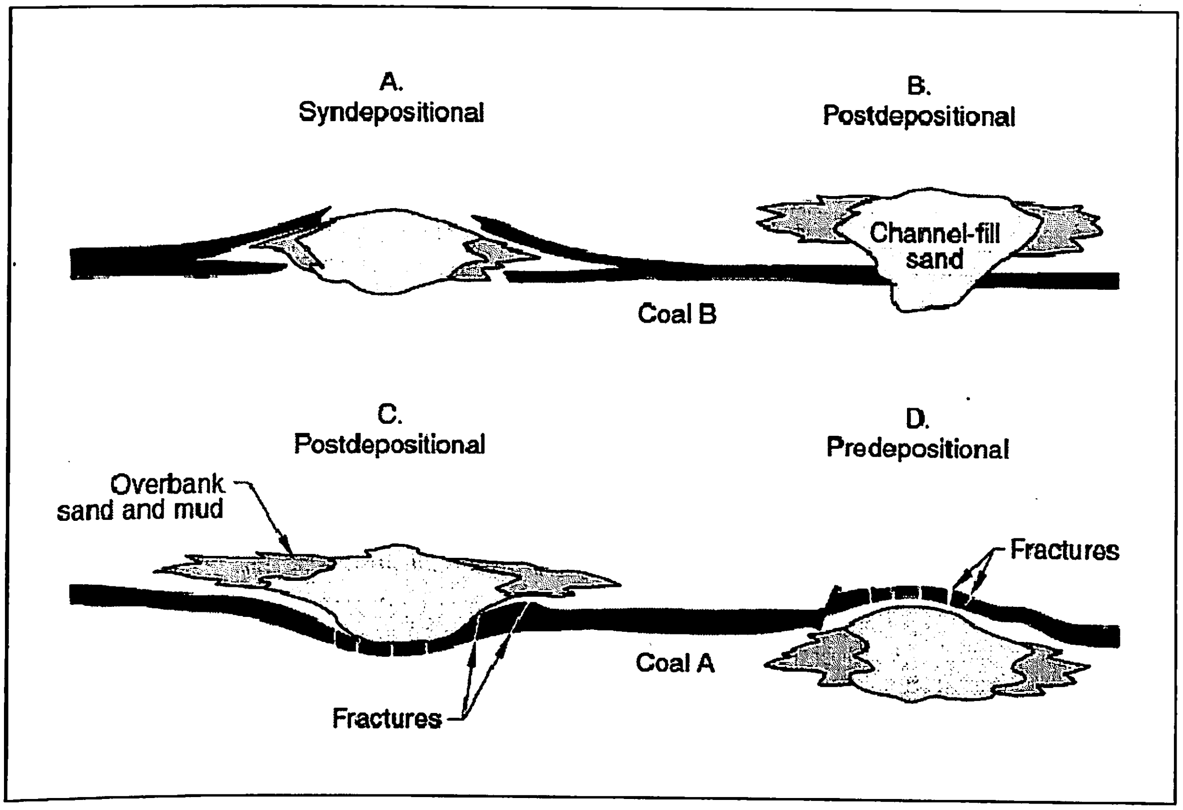
Fig. 2.2— Periods of coal formation



Donaldson has presented a concept of coal seam discontinuities that is applicable to a depositional environment, such as the Fruitland formation (Fig. 2.3)

In Sketch of Fig. 2.3, the fluvial sand deposits occurred at the same time as the peat formation to give an intertonguing of the two. In Sketch B, an intruding channel removed the peat and replaced it with sand sediments. In Sketch C, the fluvial sediments occurred after peat formation, not replacing but depositing upon the organic matter where later compaction stressed the coal. A similar stressing of the coal would occur in Sketch D where the peat formed upon the previously deposited channel sand.

Fig. 2.3—Influence of fluvial deposition on coal seam geometry.



Other large coal beds in multiple basins stretching into Canada developed along the western coast of that Cretaceous Seaway, creating a large potential CBM resource that now exists as thick coals extending along the Rocky Mountains in Montana, Wyoming, Colorado, and New Mexico. For example, the coals in Montana developed near the shoreline of the Cretaceous Seaway intertongued with the clastic sediments coming as of the mountains uplifted to the west of the shoreline.

The low sulphur content (<0.8%) of these coals indicates formation along the flood plains of the rivers coursing into the seaway as of the mountains to the west, as well as formation in fresh water behind coastal barriers, and indicates the absence of relatively high concentrations of the sulphate ion that would be in brines.

2.1.4 Carboniferous Coals of Eastern United States

Eastern U.S. coals, older by about 150 million years, exhibit many properties different as of the coals of the western states. The coals along the Appalachian Mountains were formed in the Pennsylvanian Age of the Palaeozoic era, and they usually have properties characteristic of a higher rank than the Cretaceous and younger coals.

In the Warrior basin of Alabama, the coals are located in the Pottsville formation, a 2,500–4,500-ft sandstone inter bedded with siltstone, shale, and coal beds. These coals are generally far enough along in the maturation process to exhibit a rank of high-volatile bituminous to low-volatile bituminous, an optimum rank for CBM production. The high sulphur content, 2–3% typically, indicates formation in saline waters of a shallow embayment.

2.1.5 Influence of Coal Properties

Dissimilar plant life, deposition environments, tectonic actions, residence times, and temperatures initiated coals in the two major stratigraphic periods with understandably different properties today. These differences translate into completion and production practice variations for the CBM process in the Carboniferous coals of the eastern United States and the Cretaceous or younger coals of the western part of the country. Some characteristics of the Black Warrior basin coals are compared with those of the San Juan basin in Table 2 Seam thickness and rank are the most notable differences; however, the conditions in the two regions are representative of those to be encountered worldwide in developing the CBM. As a consequence, study of the commercial processes of the Black Warrior basin of Alabama and the San Juan basin of Colorado/New Mexico will cover most of the variations to be expected worldwide.

Table 2—Comparing Coals

	Black Warrior	San Juan
Age (m.y.a.)	300	120
Rank	lvb	hvAb
Sulfur (%)	2 to 3	<0.8
Single Seam Thickness (ft)	1 to 4	30 to 50
Gas Content (scf/ton)	500 to 600	400 to 500

2.2 Coal Chemistry

2.2.1 Molecular Structure

Initially and through most of the maturation until the macerals become similar at anthracite, the chemical structure of coal is dependent on depositional environment. The type vegetation and the chemical constituents of that vegetation provide the starting material in the coalification process that later calculates parameters ranging as of the amount of gas liberated to the degree of cleating.

Type of vegetation varies with geologic age; that is, more advanced plants are expected in the Cretaceous than the Carboniferous period. Even within a given age, the vegetation varies according to locale. Further, environments of fresh water or seawater in the swamp calculate the types of plants growing there as well as the eventual sulphur and iron contents of the coal.

After the establishment of composition initially in the peat, chemical structure of the organic matter is time-dependent; structural changes become a function of burial history. In the beginning, the extent of oxidation of the plant material depends on the initial rate of water submergence, sedimentary coverage, and subsidence. Later, burial depth establishes pressure and temperature, but the time at a maximum temperature and the magnitude of the maximum temperature are the primary determinants of the dynamic chemical structure.

There is no single molecular structure that represents a coal molecule; the variation of its structure is too great. Berkowitz, however, refers to a statistical average molecule in terms of units that are most often repeated but with no intent to imply that the common structure represents all coals of all ranks.

The Berkowitz model is summarized as:

- The coal structure is envisioned as similar to synthetic compounds of copolymers, forming with varying molecular weights.
- The basic, repeating coal molecule is composed of a core of two or three condensed, aromatic rings (20–80% organic carbon).
- The clusters of aromatic rings are joined by aliphatic -CH2- and -0- linkages (10–15% of organic carbon).

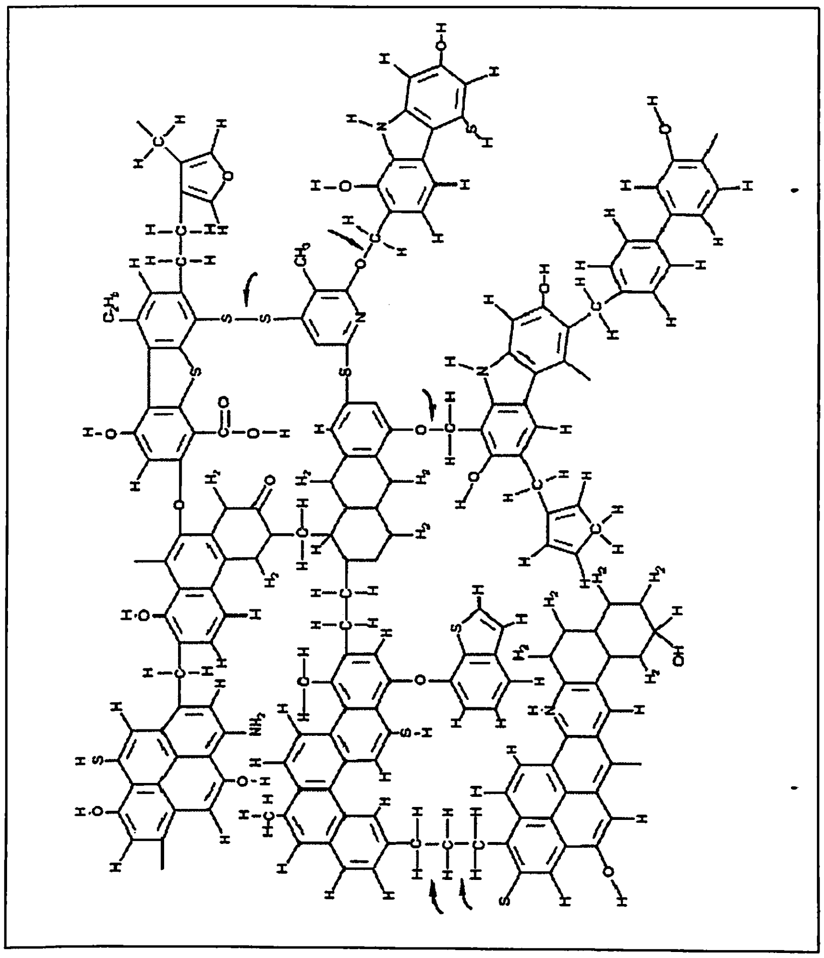
Wiser provides another model of an envisioned coal molecule in Fig. 2.4, where the primary functional groups, cyclic and aliphatic components, are represented. In the sketch, arrows indicate reactive sites of probable cleavage of the molecule. Note that the model represents clusters of three to four aromatic rings. As those weaker links between clusters break thermally during coalification, the molecule realigns, releasing volatiles and even hydrocarbon liquids in some instances. Also, condensation reactions occur, such as two aromatic molecules combining to form a single higher molecular-weight compound with the release of volatile matter.

Researchers agree that regardless of the choice of model, the coal molecule is comprised of cores or clusters of aromatic rings bridged by cyclic or aliphatic crosslink's surrounded by functional groups on the periphery. Over geologic time, under the primary influence of temperature, volatiles of CO_2, CH_4, and H_2O are released, mainly as of the non-aromatic component21 in a continual altering of the molecular structure toward an aromatic bias.

Coal has a net negative surface charge.

Attempts to study the structure of coal have been by various methods, each method providing some insight, but each being incomplete. X-ray diffraction studies, solvent extraction, and oxidation reactions have given the most information about the molecular structure of coals. The studies agree that aromatics represent 20–80% of carbon in the makeup of coal, probably closer to 32–35% as an average. The aromatic rings occur in repetitive units of two to three condensed benzene rings tied together by -O- or -CH2- groups.

Fig. 2.4—Representative coal molecule



2.2.2 Macerals

Macerals are the smallest distinguishable organic particles of coal that can be seen under a microscope. They differ in optical properties and chemical composition because of their origin in different parts of the plant.

There are three maceral groups:

- vitrinite,
- liptinite
- inertinite

➢ Their names indicating source, appearance, or reactivity. Each of the three groups contains subgroups of macerals with similarities of origin, optical properties, and

Composition.

- Generally, vitrinite is the most abundant maceral of coal and is the most homogeneous maceral. U.S. coals typically contain as much as 80% vitrinite, and it is the main contributor to the shiny black strands so familiar in coals. Vitrinite is formed partly as of lignin, an amorphous, polymeric substance that provides the structure of the plant cell wall in conjunction with cellulose.

- Additionally, vitrinite is formed as of cellulose and woody parts of the plant that create a chemical structure high in oxygen and aromatics. Its oxygen content is higher than the liptinite maceral. The vitrinite maceral is capable of producing hydrocarbon gas but only small amounts of oil; vitrinite contains more straight-chain carbon groups. Vitrinite is the maceral most conducive to forming a cleat system in coals.

- Liptinite, also called exinite, originates as of spores, pollen, resins, oily secretions, algae, fats, bacterial proteins, and waxes. Thus, it has subgroups of macerals designated as resinite, alginite, and cutinite. The cuticle refers to a thin film found on the outside walls of higher plants that is a continuous, protective, fatty deposit; the cuticle forms the cutinite maceral in the liptinite group. The macerals of liptinite have chemical structures high in hydrogen and in aliphatic. Many of the volatiles, including methane, emitted by the coal during coalification come as of the liptinite. These macerals have the potential of producing hydrocarbon gases and oil.

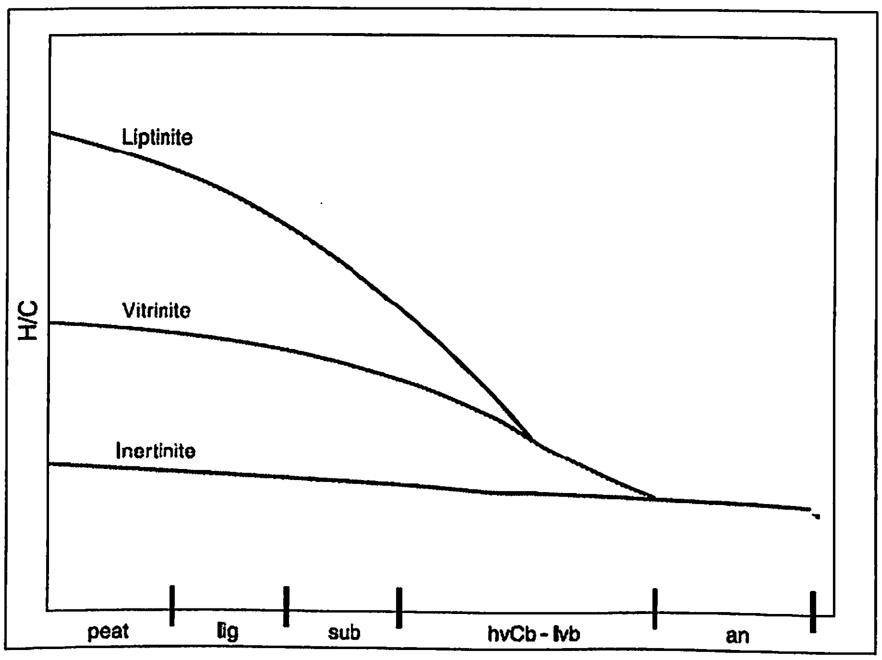
- Inertinite is the oxidized or charcoaled cell walls or trunks of plants, resulting in high carbon and aromatic content but less hydrogen. Inertinite has relatively more carbon than the other macerals, and its name is derived as of its lack of chemical reactivity. Inertinites originated as of forest fires, bacterial action, and oxidation as of the air before the coalification stage was reached. Only small amounts of volatiles are generated by the inertinites.

The entire macerals trend toward the same chemical composition as the rank of the coal increases, and they become almost indistinguishable after 94% carbon is reached. As time proceeds after deposition and geochemical reactions occur, volatile matter containing more hydrogen and oxygen than carbon is lost. Van Krevelen's graph of H/C versus O/C atomic ratios explains the convergence of the macerals in the coal. It is observed that the three macerals ultimately converge to a common composition.

Another way of viewing Fig. 2.5 is that maturity is a function of the hydrogen-to-carbon ratio of the coal's molecular structure. To a large extent, the ratio reflects the coal's capability to evolve methane during coalification. Therefore, as of an interpretation of Fig. 2.5, liptinite is most responsible for methane generation. Inertinite contributes little to methane generation.

In Fig. 2.5, whereas liptinite and vitrinite attain the same composition, carbon represents about 89% of the elemental analysis. At 94% carbon, the three macerals become almost indistinguishable; their reflectance is similar at 95% carbon. At this latter point, the weaker bonds of functional groups have been broken, volatiles have been evolved, and the structure has reduced to the stronger bonds of the aromatic clusters arranged in a more orderly manner. Physical and chemical properties of the coal have therefore changed accordingly.

Fig. 2.5—Convergence of macerals



2.2.3 Lithotypes

On a microscopic basis, macerals classify the makeup of coal according to the plant source. On a macroscopic basis, lithotypes classify bands of coal that are visibly discernible according to their dominant and minor maceral contents. It is a classification intended to describe coal composition by means of the brightness or dullness of the bands to the unaided eye.

The four lithotypes are:

• Vitrain.
• Clarain.
• Durain.
• Fusain.

- Vitrain is composed primarily of vitrinite. Minor amounts of the inertinite and liptinite macerals are present. They are the familiar bright black bands seen in coal. Vitrain is friable and brittle and thus plays an important role in cleat formation. Fissures are common in it, and because of this, the fines generated in a producing CBM well should be weighted toward the vitrain. Vitrain is the most important litho type in establishing a successful CBM.

- Although a bright component of coal, clarain is not as bright as vitrain. It contains less vitrinite and more inertinite and liptinite. The presence of inertinite hinders the formation of fractures; inertinite is hard and difficult to crush.

- Durain is a dull lithotype. It contains more mineral matter and inertinite than vitrain or clarain. It is tough and difficult to fracture. Therefore, blocks of it, rather than the fines, would separate as of the seam. Durain is not conducive to building good permeability in a coal seam.

- Fusain resembles charcoal. It is fibrous and soft and is easily broken. Fusain is the least important of the lithotypes in the CBM process.

Obviously, the greatest usefulness of the lithotypes to the CBM process lies in easily distinguishing the bright bands where vitrinite is concentrated. These components of such bright bands impart to the coal fracturing characteristics that are precursors of good permeability.

2.3 Significance of Rank

Coal progresses through a maturation process driven primarily by temperature and secondarily by time and pressure that goes as of the freshly deposited organic matter in swamps to a graphite-like material at the end of the progression. Physical as well as chemical properties of the coal change along the route, and properties that are stereotyped for discrete points in the maturation are developed. Rank is used to define these discrete points in the maturation process. Rank is a harbinger of success of any prospective CBM venture because it implies the potential for gas content, permeability, and mechanical and physical properties of the coal. Rank may vary laterally and vertically within a seam, and it varies as of seam to seam within a given coal group.

Chapter 3: Reservoir Analysis

3.1Coal as a Reservoir

During the progression of coalification as of peat to anthracite, an order of magnitude more methane may be generated than can be retained by the coal. Under proper conditions, the expelled gas may charge adjacent sands as evidenced by Pictured Cliffs sandstone conventional gas fields below Fruitland coals of the San Juan basin and by Trinidad sandstone below Vermejo coals of the Raton basin. Coal is an important source rock for natural gas, and commercial advantage has long been taken of this fact.

Coal is also a reservoir rock, but only in the development of the coal bed methane (CBM) process has this fact been commercially exploited. Even though the coal may retain only a fraction of the gas it generates as a source rock, that fraction may represent two to seven times more gas per unit volume as a reservoir rock than a conventional gas reservoir. This is because the coal may have 1 million ft^2/lbm of adsorption surface area and the adsorbed methane concentration may approach liquid density.

Similarities between the coal bed reservoir and the conventional sandstone or carbonate reservoir exist, and because of some similarities, oilfield technology may be used. However, differing phenomena in the relatively low-pressure coal bed reservoir have necessitated innovations, modifications, and limitations to conventional oilfield technology. Applied research has allowed adaptation of the oilfield processes. For example, different mechanical properties of the coal and formation susceptibility to chemical damage required study and modification of conventional fracturing and completion techniques. The concept of adsorption and attendant water problems was introduced into the analysis of a reservoir. Comparisons of general properties of a conventional gas reservoir and a coal reservoir are presented in Table 3.

Table 3—Coalbeds and Conventional Reservoirs Compared

Conventional Gas	Coalbed
Darcy flow of gas to wellbore.	Diffusion through micropores by Fick's Law.
	Darcy flow through fractures.
Gas storage in macropores; real gas law.	Gas storage by adsorption on micropore surfaces.
Production schedule according to set decline curves.	Initial negative decline.
Gas content from logs.	Gas content from cores. Cannot get gas content from logs.
Gas to water ratio decreases with time.	Gas to water ratio increases with time in latter stages.
Inorganic reservoir rock.	Organic reservoir rock.
Hydraulic fracturing may be needed to enhance flow.	Hydraulic fracturing required in most of the basins except the eastern part of the Powder River basin where the permeability is very high. Permeability dependent on fractures.
Macropore size:[3] 1µ to 1 mm	Micropore size:[3] <5A° to 50A°
Reservoir and source rock independent.	Reservoir and source rock same.
Permeability not stress dependent.	Permeability highly stress dependent.
Well interference detrimental to production.	Well interference helps ~~production~~. Must drill multiple wells to develop.

To develop the coal beds economically, gas content and permeability of the reservoir must meet minimum criteria that may be about 150 scf/ton gas content in thin seams and md permeability. A minimum criterion of permeability is required before hydraulic fracturing can successfully interconnect the natural cleat system to the wellbore. Exceptions exist. For example, the extraordinarily thick coal seams of the Powder River basin are economical at lower gas contents.

Ordinarily, these reservoir characteristics must be calculated to be above their minimum values before developing a field. Later, development centres on resolving questions of water production, water disposal, well interference effects, completion techniques, and well spacing.

The mechanism for gas flow in the coal involves three steps:

(1) Desorption of the gas as of the coal surface inside the micro pores,
(2) Diffusion of the gas through the micro pores, and
(3) Darcy flow through the fracture network to the wellbore.

Multiple wells in the field are necessary to remove water, where well-to-well interference is a positive factor. Faults and joints throughout the formation play an important role. Therefore, the interplay of many parameters in the reservoir is a complexity that requires simulation to fully understand overall performance. Consequently, simulation has been used extensively as of the beginning of the CBM process, making the coal bed process possible and establishing itself as an essential analysis tool.

3.2 Permeability

Permeability is the most critical parameter for economic viability of a gas-containing coal; the network of natural fractures along with any hydraulic fractures must supply the permeability for commercial flow rates of methane. It is also the most difficult parameter to estimate accurately. Therefore, the frequency of the natural fractures, their interconnections, degree of fissure aperture opening, direction of butt and face cleats, water saturations, burial depths, matrix shrinkage upon desorption, and in-situ stresses all affect permeability. The determination of gas effective permeability is further complicated by the changing nature of gas relative permeability with water content in the flow path.

Spafford and Schraufnagel estimated with a simulator the effect of coal seam permeability's on production for various hydraulic fracture half-lengths in the Warrior basin. Their results are presented in Fig. 3.1. It is evident as of the work those natural permeability's of this Warrior basin coal:

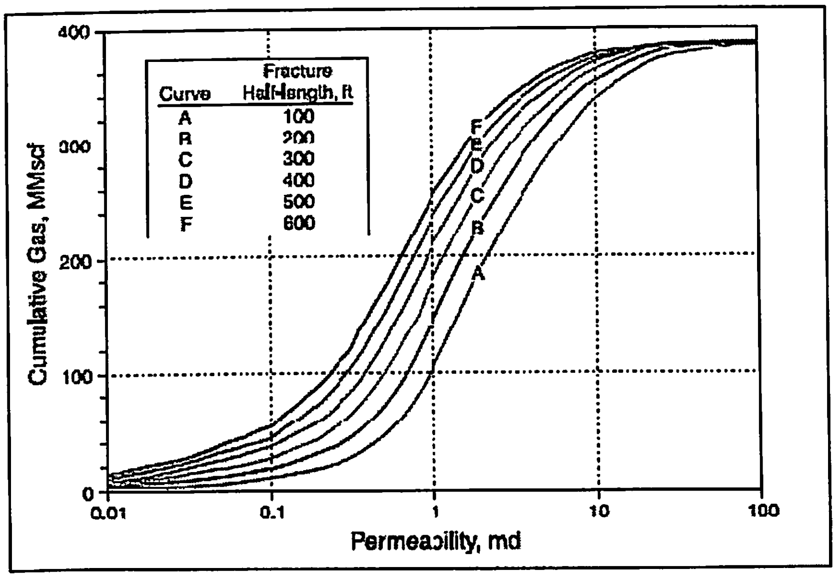
• Less than 0.1 md hold little promise of improvement in gas production as of fracturing.

• With initial permeability's between 0.1 and 1.0 md are marginal for development after fracturing.

• With permeability's between approximately 1.0 and 10.0 md can have production enhanced greatly by fracturing.

Although the results are derived for the Mary Lee coal group at Rock Creek, the effect of permeability on well performance and fracture design should be qualitatively representative of other basins.

Fig. 3.1—Results of a simulator estimation of the effect of coal seam permeability's on production for various hydraulic fracture half-lengths in the Warrior basin



Therefore, how the reservoir is treated depends on permeability, and the permeability's of natural cleat systems vary as of basin to basin and as of coal seam to coal seam. Values can range as of impermeable to >100 md. How are the cleats formed? Insight into this question might assist the engineer in planning and managing the reservoir development. Natural fractures occur during coalification as of shrinkage of the coal matrix after loss of volatiles. Folding or tectonic action over geologic time further extends the fracturing network. Additionally, differential compaction of coal seams and adjacent sediments possibly contribute to the cleat network in coals, but the effect is probably minor. Maceral content influences the frequency of cleats in the coal, as does the coal rank at the time tectonic action occurred. Mineral matter in the coal has a deleterious effect on cleat formation.

Table 4 gives a few representatives, absolute permeability's of major coal seams whereas active CBM projects exist. The tabulation implies a diversity of permeability's in commercial projects, and it also suggests a dependence of permeability on depth and the in-situ stresses that normally increase with depth. The CBM process for the first time has emphasized the importance of in-situ stresses in the formation.

Table 4—Representative Permeabilities

Location	Permeability (md)
Cedar Cove, Brookwood, Oak Grove Fields in Warrior Basin[6]	100 at 100 ft 10 at 1,000 ft
U.S. Steel Well 1036, Appalachian Basin[7]	20
Upper Fruitland, NE Blanco Unit, San Juan Basin[8,9] Upper Fruitland, Tiffany Project Area[10] Basal Fruitland, Tiffany project Area[10]	 1.5 to 8.8 1.5 4.5
Mary Lee (Upper Group) Black Creek (Lower Group)	10 to 25 0.5 to 3.5
Cedar Hill, San Juan Basin[11] • Butt Cleat Direction • Face Cleat Direction	 4 12

Determining the permeability of a prospective coal reservoir is of major importance. Insight into permeability as of the extent and direction of fracturing in coals of undeveloped areas has been sought through the study of surface lineaments revealed by satellite and aerial photographs. As of these photographs, directional trends can be defined, but an acceptable general correlation with permeability has not been achieved.

Even with core tests, accurate measurement of permeability is difficult. Because permeability of coal is a function of stress, values measured in the laboratory cores may not be accurate. Also, since the permeability of coal is a function of sample size, values measured in the laboratory tend to be less than those realized in the field because the small cores may not sample fractures or joints. Laboratory results can be a factor of 10 lower than permeability's experienced in the field. It is possible that damage to the cores may result upon extraction, and it may be impossible to reproduce the formation stresses in the laboratory. Hence, it is necessary to calculate permeability as of history matching production data or as of one of the following pressure transient tests:

- Drill stem test (DST).
- Slug test.
- Injection falloff tests (IFT).
    - Tank test.
    - Below fracture pressure injection falloff test (BFP-IFT).
    - Diagnostic fracture injection test (DFIT).
- Pressure build up test (PBU).
- Multi-well interference test.

Relative Permeability

To estimate accurately the productivity of a CBM well over its life, it is important to know the effective permeability of methane in the reservoir at all production stages. Initially, the cleats are expected to be fully occupied by formation waters. At this point of one-phase saturation, an injection falloff test can calculate the absolute permeability. After the peak gas production rate is reached, water content in the coal slowly trends toward an irreducible amount, and the production rate of the water eventually should become small. As Seidle points out, this eventual condition approaching single-phase gas flow may endure for a large fraction of the economic life of the well. In such cases, the effective permeability of the gas can be estimated.

Relative permeability of gas is the ratio of effective permeability of the gas to absolute permeability given as:

$$k_{rg} = \frac{k_g}{k}$$

Whereas,

k_{rg} = relative permeability to gas
k_g = effective gas permeability
k = absolute permeability as defined by Darcy's law

3.3 Porosity

Coal has a dual porosity system. Macro pores are the spaces within the cleat system and other natural fractures essential for the transport of water and methane through seams but relatively unimportant for methane storage. The storage space of the cleats and other natural fractures contains water, free methane, and methane dissolved in water, but primarily the porosity of the macro pores calculates the storage capacity for water. The macro pore porosity has a direct impact on operating costs to handle and to dispose of formation waters that are produced.

Less than 10% of the in-place gas of a coal seam resides in the cleats. The porosity of the macro pores of the cleat system is generally considered to range between 1–5%. The primary porosity of the Oak Grove, Alabama coals is reported at 2.8% for the Jagger group. The cleat porosity of the San Juan basin, Ignacio, is reported to be 2.4%. In the simulation work of Young, porosities in the Cedar Hill field of the San Juan basin were estimated by history matching of production data to be an average of 0.25%. Such low porosities would give significantly less water storage and have a positive impact on process ecomicro poresicropores refer to the capillaries and cavities of molecular dimensions in the coal matrix that are essential for gas storage in the adsorbed state. Most of the gas is contained in the micro pores, adsorbed on the particle surface; Gray estimates that 98% of the methane is typically adsorbed in the micro pores.

Although coal porosity may be only 2% in the cleat system, it may have a storage capacity for methane in the micro pores equivalent to that of 20% porosity sandstone of 100% gas saturation at the same depth. A large surface area necessarily exists for adsorption. It is reported that a 1-lb sample of Fruitland coal contains an internal surface area of 325,000 sq ft. McElhiney states an internal surface area of nearly 1 million sq ft per pound of coal. Thus, a seeming paradox exists because very large volumes of methane can be stored in the coal's micro pores despite a low porosity.

3.4 Reserve Analysis

3.4.1 Gas in Place

To estimate the value of methane reserves in coal beds, as in the development of a conventional gas property, an estimate is first made of the initial in-place gas. However, estimation of in-place gas in coal seams is less accurate and more difficult than conventional reservoir engineering methods. One of the complicating factors is the inability to use well logs to obtain gas content of the coal. Because the geophysical logs cannot detect gas contained in the coals, as with sandstone or carbonate reservoirs, the methane content must be calculated as of a controlled desorption of retrieved cores—a costly, time-consuming task. In the method of core analysis, gas content is the sum of the quantity of gas desorbed as of the coal in the canister and an estimated quantity of gas lost during core retrieval.

The procedure for determining gas content of a reservoir as of cores is as follows:

1. Cores are removed as of the formation, retrieved to the surface, and transferred rapidly to a sealed container to minimize lost gas.

2. Reservoir temperature is established in the canister.

3. The rate and quantity of gas desorbed in the canister at reservoir temperature are recorded.

4. When gas flow stops at atmospheric pressure, the sample is crushed, and the gas released as of the crushed coal is monitored. This gas is residual gas.

5. The gas lost during removal of the core as of the well is estimated as of a plot of the quantity of gas desorbed when the core is initially placed in the canister vs. $t^{1/2}$ by extrapolating to the time of extraction as of the formation. The sum of gas desorbed in the canister, residual gas, and lost gas represents gas content of the coal.

There are six ways the gas content of a coal can be reported:

a) Raw or As-Received.

b) Inert Gas-Air Dry.

c) Dry, Ash-Free.

d) Dry, Ash-Residual Moisture-Sulphur Free.

e) Theoretically Pure-Coal.

f) In-situ.

It is very important to understand the definition of each basis and use them accordingly.

3.4.1.1 Gas Content: Raw or As-Received

The gas content of a coal reported on a raw basis is calculated using the weights of all material in the original sample. Therefore, the reported weight contains original moisture as well as any non-carbonaceous materials. This method provides a preliminary estimate of total gas content. Eq. 3.1 describes the gas content obtained on this basis.

$$GC_{RAW} = 32.0368\left\{\frac{V_{LG} + V_{RG} - V_{MG}}{W_{RAW}}\right\}$$

____Eq^n 3.1

Whereas,

GC_{RAW} (scf/ton) = gas content-Raw

V_{LG} (cm3) = lost gas volume at STP

V_{RG} (cm3) = residual gas volume at STP

V_{MG} (cm3) = measured gas volume at STP

W_{RAW} (grams) = weight of the raw coal sample

3.4.1.2 Gas Content: Inert Gas-Air-Dry

The main difference between raw and inert-gas-air-dry basis is that the gas content calculated on a raw basis is corrected by removing the weight of water as of the raw sample. Basically, any extra material is removed as of the sample by allowing the raw sample to air-dry in a laboratory environment until an equilibrium weight is obtained. This usually takes about 48 hours and is done in an inert environment to prevent oxidation. Eq. 3.2, shown below provides the gas content obtained in this basis.

$$GC_{Air-dry} = 32.0368\left\{\frac{V_{LG} + V_{RG} + V_{MG}}{W_{Air-Dry}}\right\}$$

_________ Eq. 3.2

Whereas,

GC_{Air}-Dry (scf/ton) = gas content-inert gas-air-dry basis
W_{Air}-Dry (grams) = weight of the air-dry coal sample

The sample weight calculated here is the basis for estimating the next two gas contents.

3.4.1.3 Gas Content: Dry, Ash-Free

Once the sample is air-dried, there is still some moisture left in the coal referred to as residual moisture. There is also some ash left in this coal. The weight of the residual moisture and ash are calculated as per ASTM standards, D3173-03 and D3174-04 and the air-dry sample weight is adjusted for these two weights using Eq. 3.3

$$W_{DAF} = W_{AIR-DRY}\{1 - WF_{RMC} - WF_{DASH}\}$$

_________ Eq. 3.3

Whereas,

WF_{RMC} (weight-fraction) = residual moisture content
WF_{DASH} (weight-fraction) = dry ash content
W_{DAF} (grams) = weight of the dry, ash-free coal sample

After the weight of dry, ash-free coal, *WDAF* is estimated; the gas content is then calculated using Eq. 3.4.

$$GC_{DAF} = 32.0368\left\{\frac{V_{LG} + V_{RG} + V_{MG}}{W_{DAF}}\right\} \qquad \text{\_\_\_\_\_\_\_\_\_\_ Eq. 3.4}$$

Whereas,

GC_{DAF} (scf/ton) = gas content-dry, ash-free basis

If dry, ash-free gas in place is to be calculated, the density of coal on a dry, ash-free basis is required. This density can be estimated using Eq. 3.5.

$$\rho_{DAF} = \left\{\frac{\rho_a * \rho * (100 - DASH)}{100 * \rho_a - \rho * DASH}\right\} \qquad \text{\_\_\_\_\_\_\_\_\_\_ Eq. 3.5}$$

Whereas,

ρ_{DAF} (gm/cm3) = density of coal, dry, ash-free basis
ρ_a (gm/cm3) = density of dry ash
ρ (gm/cm3) = density of dry coal containing ash
DASH (weight %) = dry ash content

The dry, ash-free gas content should be reported only for coals containing less than 40% by weight ash and moisture because it can otherwise be incorrect if a significant amount of mineral matter is present in coals of lower quality. Please note that during the ash analysis, sulphur gets vaporized and therefore ash analysis cannot sufficiently account for the weight effect of sulphur present in coals. How to account for the weight fraction of sulphur present in coals is discussed in the next section.

3.4.1.4 Gas Content: Dry, Ash-Residual Moisture-Sulphur-Free

The non-coal components in coal are residual moisture, ash, and sulphur. Adjusting for moisture and ash content weight would be sufficient to account for the non-carbonaceous components in many coals except when pyrite or carbonate minerals are present. In such cases, the sulphur content in coals should also be accounted for since it is also a non-carbonaceous component. The weight fraction of sulphur should be calculated as per the ASTM standards, D3177-02 and D1757-03, and must be corrected as of the weight of the air-dry sample.

The dry, ash-residual moisture-sulphur-free sample weight can then be estimated using Eq. 3.6.

$$W_{DAMSF} = W_{AIR-DRY}\{1-(WF_{RMC} + 1.08WF_{AR-ASH} + 0.55WF_{AR-TSC})\}$$

__________ Eq. 3.5

Whereas,

W_{DAMSF} (grams) = weight of the dry, ash-residual moisture-sulfurfree coal sample
$W_{Air-Dry}$ (grams) = weight of the air-dry coal sample
WF_{RMC} (weight-fraction) = residual moisture content
WF_{AR-ASH} (weight fraction) = as-received ash content
WF_{AR-TSC} (weight fraction) = as-received total sulphur content

Once the weight of residual moisture, ash, and sulphur are accounted for, the dry, ash-residual moisture-sulphur-free gas content can be calculated using Eq. 3.7.

$$GC_{DAMSF} = 32.0368\left\{\frac{V_{LG} + V_{RG} + V_{MG}}{W_{DAMSF}}\right\}$$

__________ Eq. 3.7

Whereas,
GC_{DAMSF} (scf/ton) = gas content-dry, ash-residual moisture-sulphur free basis.

3.4.1.5 Gas Content: Theoretically Pure Coal

The maximum gas content obtained by performing regression analysis on inert gas-air-dry, gas content data obtained as of multiple samples plotted against the corresponding non-carbonaceous weight fraction data and extrapolated to zero non-carbonaceous weight percent is referred to as the pure-coal gas content. This term has been loosely used and incorrectly switched with dry, ash-residual moisture-sulphur-free gas content.

Like any statistical analysis, this method can be applied only when sufficient sample volumes containing a wide range of ash sulphur, and residual moisture contents are available. It is essential to have sufficient sample numbers to obtain statistically accurate theoretically pure-coal gas content estimates. This gas content estimate is mainly used as a basis to compare gas contents as of coal samples in various other locations.

The example in Fig. 3.2 is as of a CBM well in the Tiffany area of the San Juan basin. As shown, there is an inverse relationship between the total air-dry basis gas content and the corresponding non-coal component weight fraction. The theoretically pure-coal gas content estimated in this example using linear regression is 495scf/ton. The correlation coefficient obtained as of this linear regression analysis is 0.77. Additional desorption sample test data would have improved the correlation coefficient. By comparing it with the isotherm storage capacity, the theoretically pure-coal gas content is used to calculate the degree of saturation and also the effect of other gases like carbon dioxide and nitrogen.

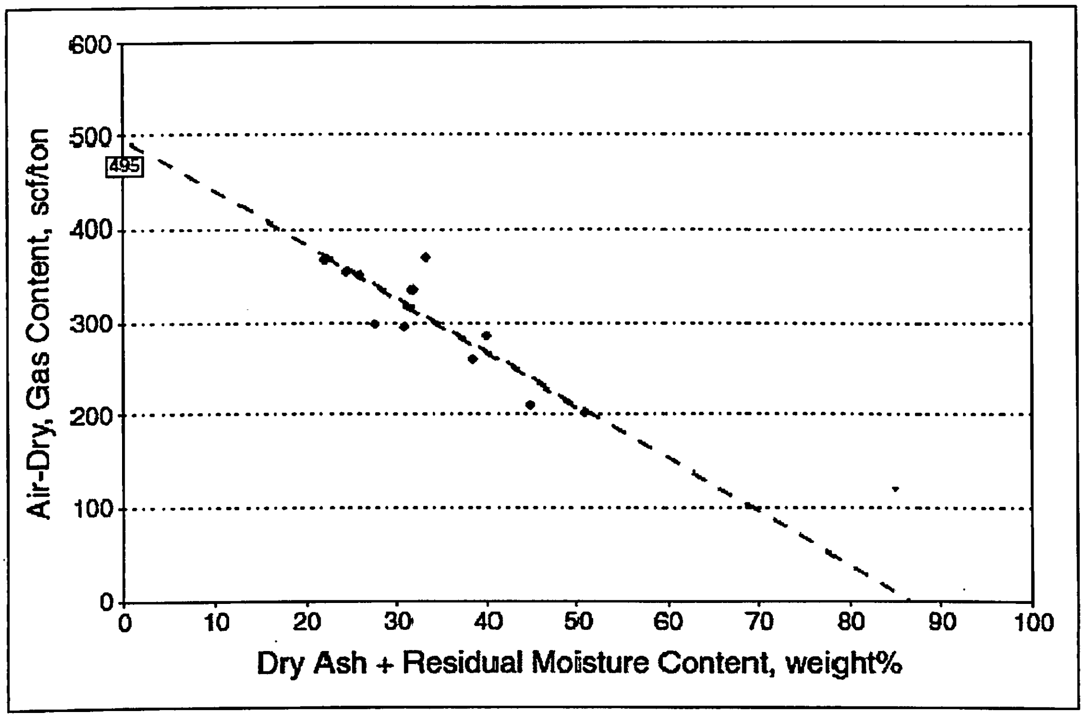


Fig. 3.2—"Pure Coal" gas content estimation, San Juan Basin.

3.4.1.6 Gas Content: In-Situ

Once the theoretically pure coal gas content is known, the in-situ gas content can be estimated using the residual moisture and dry ash content. In-situ gas content can be calculated using Eq. 3.8.

$$GC_{In-situ} = GC_{PC}\{1 - WF_{DASH} - WF_{RMC}\} \qquad \text{Eq. 3.8}$$

Whereas,

$GC_{In\text{-}situ}$ (scf/ton) = gas content-in-situ basis

GC_{PC} (scf/ton) = gas content-pure-coal basis

WF_{RMC} (weight-fraction) = residual moisture content

WF_{DASH} (weight-fraction) = dry ash content

When pure coal gas content is not available, it can be replaced by dry, ash-free or dry, ash-residual moisture-sulphur-free gas content estimates. It was found that a correlation exists between ash content and bulk density measured wire lineine logs. The correlation is represented by Eq. 3.9.

$$WF_{DASH} = \left\{ \frac{\rho - \rho_c}{\rho_a - \rho_c} \right\}$$

_________ Eq. 3.9

Whereas,

WF_{DASH} (weight fraction) = dry ash content
ρ (g/cm3) = measured bulk density of coal
ρ_c(g/cm3) = density of "pure" coal
ρ_a (g/cm3) = density of ash

Based on this correlation, it is possible to calculate gas content of coal as of the logs. However, if the log data are not calibrated for accurate pure coal and ash densities, the resulting gas content estimates will be inaccurate.

Therefore, adequate core sampling, representative of the reservoir, proper laboratory analyses, correct accounting of lost gas, and correct interpretation of data make the methane reserve estimation more difficult and more costly than for conventional reservoirs.

Once the in-situ gas content is known, the in-place gas is calculated by multiplying it by the weight of coal and then adding a term for the free gas in cleats as in Eq. 3.10.

$$G_I = V_C + 1359.7 Ah\bar{\rho}(GC_{In-situ})$$

_________ Eq. 3.10

Whereas,

G_I (scf) = initial gas in place
V_C (scf) = volume of free gas in cleats

A (acres) = surface area of the reservoir (drainage area)

h (ft) = net coal thickness

(g/cm^3) = average bulk density of coal

$GC_{In\text{-}situ}$ (scf/ton) = gas content-in-situ basis

The height of the seam should come as of high-resolution density logs. To calculate accurate values of the thickness and to exclude the inorganic partings, high-resolution density logs are desirable for the thin seams. Use of conventionally run logs may result in overestimating the seam thickness. If gas content and density of coal in Eq. 3.11 is to be reported on a mineral-free basis, the height of the coal seam must be mineral-free. When reporting gas in place, mixing the measurement bases can lead to errors, especially in coals with high ash content. The volume of free gas in the cleats in Eq. 3.11 is expanded by Holditch and Zuber into a more useful form as given in Eq. 3.12.

$$G_I = A(\Sigma h)\{43.560\phi_C(1 - S_{WC})B_g + 1.36\bar{\rho}(GC_{In-situ})\} \quad \text{\_\_\_\_\_\_\_\_ Eq. 3.11}$$

Whereas,

G_I (Mscf) = initial gas in place

φ_C (fraction) = cleat porosity

S_{WC} (fraction) = water saturation in cleats

B_g (Mscf/ft3) = formation volume factor of gas

Σh (ft) = net coal thickness

Only a relatively small portion, less than 10% of the total gas in place will be in the cleats in free-form. Hence Eq. 3.11 can be simplified into Eq. 3.12.

$$G_I = 1359.7 A h \bar{\rho}(GC_{In-situ}) \quad \text{\_\_\_\_\_\_\_\_ Eq. 3.12}$$

Eq. 3.12 can be rearranged to represent dry, ash-free gas content in the manner of Eq. 3.13.

$$G_I = 1359.7 A h \bar{\rho}_{DAF} (GC_{DAF})(1 - WF_{DASH} - WF_{RMC}) \qquad \text{\_\_\_\_\_\_\_\_\_ Eq. 3.13}$$

Whereas,

G_I (scf) = initial gas in place

$GC_{DA}F$ (scf/ton) = gas content, dry, ash-free basis

ρ_{DAF} (gm/cm3) = average density of coal, dry, ash-free basis

WF_{RMC} (weight-fraction) = residual moisture content

WF_{DASH} (weight-fraction) = dry ash content

Recoverable reserves of methane may be calculated as of initial gas in place. Estimated recoveries by volumetric calculations are the product of initial hydrocarbons in place times a recovery factor which may be represented by Eq. 3.14.

GR = Gi Rf _________ Eq. 3.14

Whereas,

R_f= recovery factor

G_i = initial gas in place

G_R = methane recoverable reserves

The recovery factor is estimated as of the isotherm for that coal (refer to Fig. 3.3).

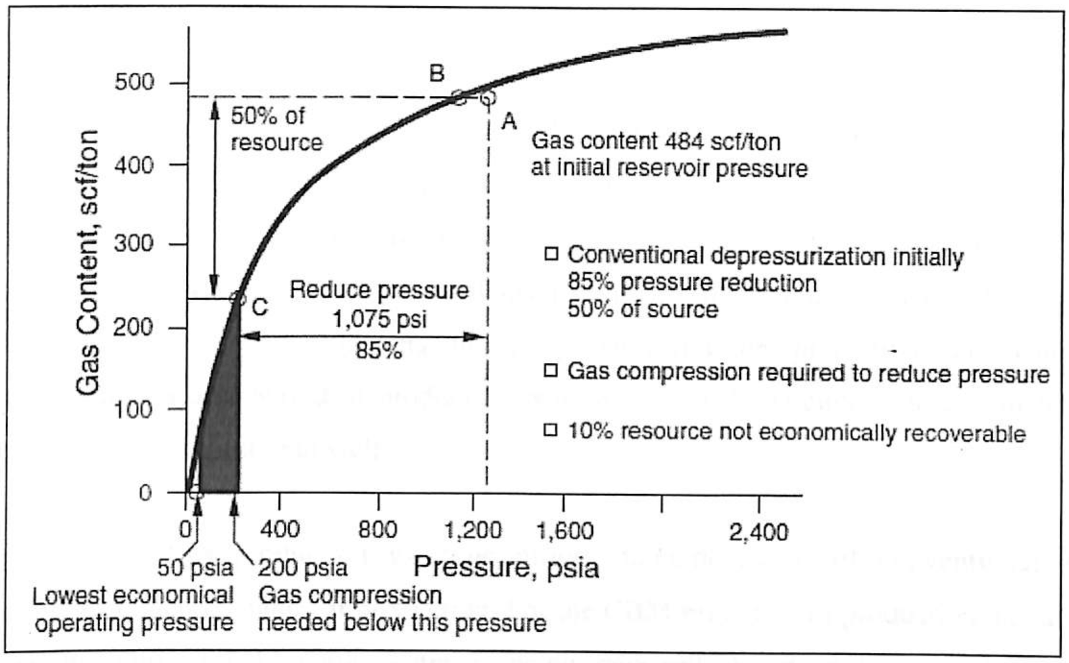


Fig. 3.3—Estimating reserves and recovery factor

The abandonment pressure establishes the residual gas in the coal at abandonment.

$$R_f = \frac{V_i - V_a}{V_i}$$

Eq. 3.15

Whereas,

R_f = recovery factor

V_i = initial volumetric gas content, scf/ton

V_a = abandonment gas content, scf/ton

In Fig. 3.3, it is seen that 50% of the gas is recovered as of reducing pressure by 1,075 psi to the pressure where gas compression is needed for the sales line. At the abandonment pressure of 50 psi, a recovery factor of about 90% is calculated as of Eq. 3.15.

3.4.2 Decline Curves

A classical method to calculate conventional oil and gas reserves is decline curve analysis. Decline curves have long been used in the oil and gas industry to fit the production time data of producing properties. After an initial decline pattern has been established, the subsequent decline usually follows an exponential, hyperbolic, or harmonic pattern that allows the prediction of each year's production until abandonment. Anticipation of cash flows and ultimate profitability of the producing unit are possible if future production rates can be calculated. An adequate period of production is necessary in the beginning to establish the decline pattern of conventional wells.

The profile of CBM production vs. time differs dramatically as of conventional gas production during early stages of production. For the CBM process, gas production increases (negative decline) initially while water is being removed, followed by a peak in gas production and then a long decline. Fig. 3.4 gives the production profile of Well OG-134 of the Oak Grove field in the Warrior basin.

Note that about 11 months was required for dewatering and gas desorption near the wellbore to establish peak gas production, plus another 7 months to begin a steady decline rate.
Would be inapplicable, but on the positive decline side, it may be beneficial if the production as of the subject well has no interference as of adjacent wells.

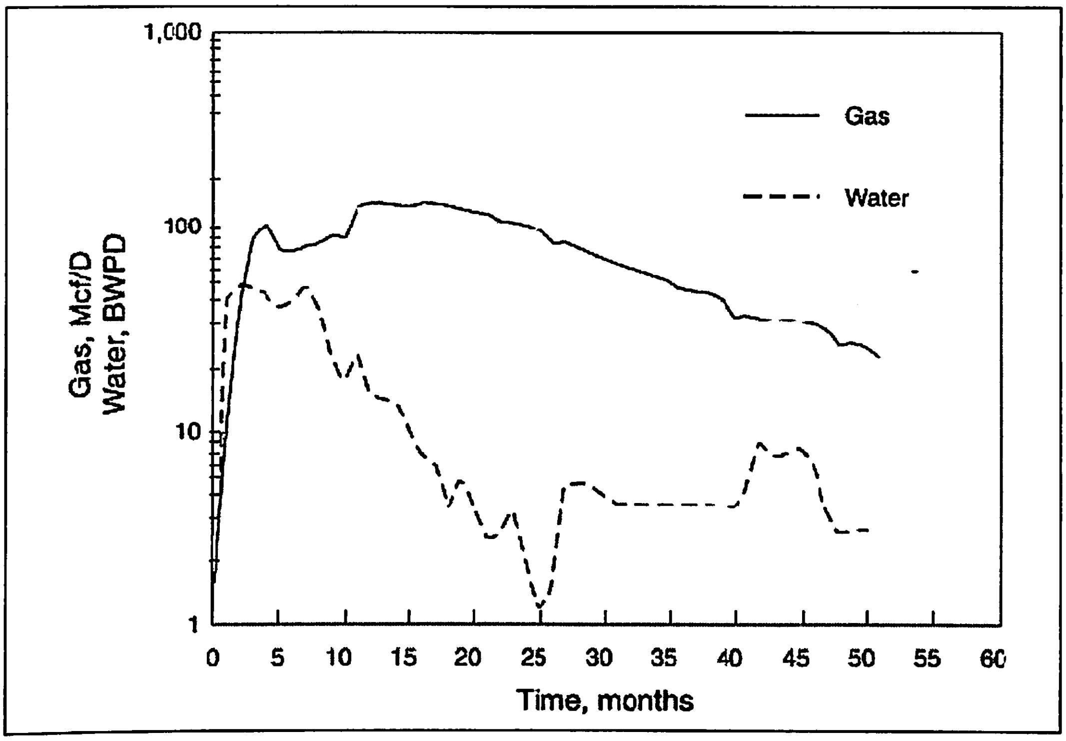


Fig. 3.4—Typical production curves

Therefore, it is desirable to forego decline curve analysis until the decline side of the gas production curve represents at least 22 months of production, of which at least 6 months show a consistent decline slope.

Exponential decline is described by Eq. 3.16.

$q = q\ e\text{-}Dt$

__________ Eq. 3.16

Whereas,

q = producing rate at time t, vol/unit time

q_i = producing rate at time 0, vol/unit time

D = nominal exponential decline rate, 1/time

t = time

e = base of natural logarithms, 2.718

Any consistent set of units is permissible.

A plot of production rate vs. time on semi log paper should give a straight line if the well exhibits exponential decline. Fig. 3.5 is an example of exponential decline in the Deerlick Creek field of the Warrior basin after peak production.

Production as of the well depicted in Fig. 3.5 declines at the rate of 15.1 year to an assumed economic limit of 40 Mcfd in 137 months. As of the information, a schedule of cash flows can be made, abandonment time predicted, and ultimate reserves estimated. Profitability of the well can then be estimated.

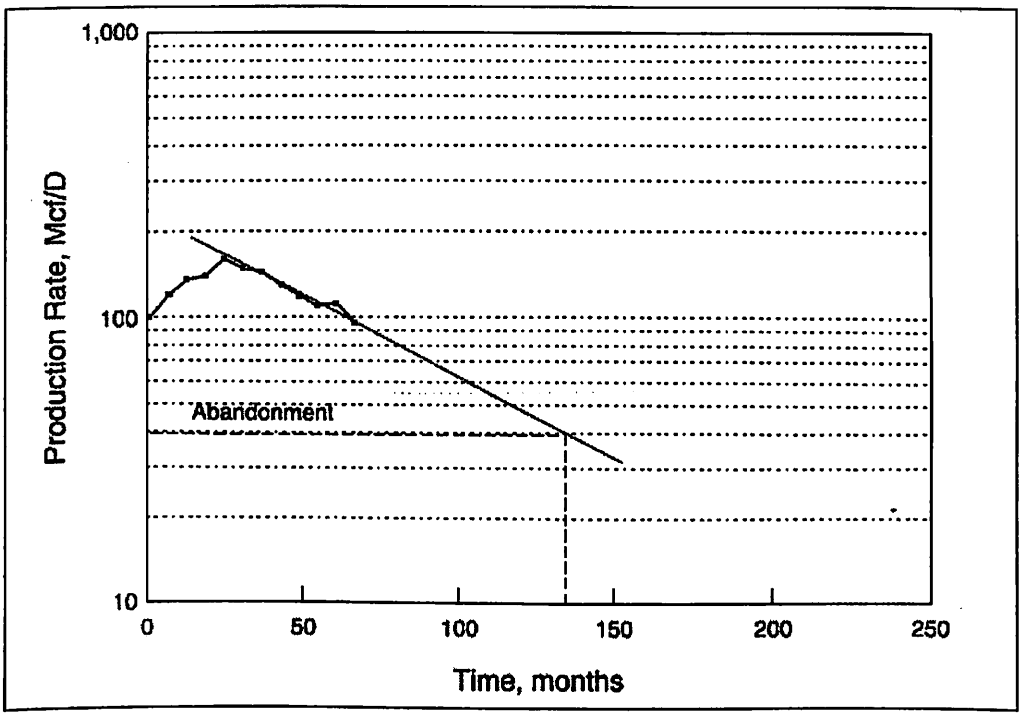


Fig. 3.5—Exponential decline, Deerlick Creek well

Chapter 4: Enhanced Recovery

4.1 Introduction

Technical advancements have made the CBM process a commercial reality, and it has been the additional technical innovations that have sustained the process. Enhanced recovery might possibly provide the breakthrough in the future that would make marginal coal properties economically attractive and possibly make deep coals viable targets. Three accomplishments would be desired:

1. Increase the ultimate reserves.
2. Accelerate the production.
3. Improve the process profitability.

The ultimate reserves are defined as the initial methane adsorbed on the coal plus free gas in the cleats minus the amount of the gas that must be left adsorbed and free in the coal at the economic limit of production. To increase ultimate reserves significantly, the enhanced recovery process would need to reduce the amount of gas left adsorbed in the micro pores at the economic limit and accomplish the reduction economically.

If time to produce the reserves might be shortened (even without increasing ultimate reserves), improvements in rates of return on the investment might justify additional costs. A 20-year production schedule of a CBM well, for example, reduced in time to a few years, would take advantage of the time value of money.

Enhanced recovery of methane is possible done using two methods:

- Using the first method, the partial pressure of methane is reduced by injecting an inert gas, such as helium or a gas that adsorbs more weakly than methane in coal, such as nitrogen (N2), into the coal seams and thus maintaining the total pressure. Since the partial pressure of methane is reduced, it desorbs to achieve partial pressure equilibrium. Since helium is more expensive and scarce to obtain, nitrogen, which is cheap and abundant, is used in this process. This process is also referred to as methane stripping. Amoco (now BP) reported initial laboratory research on this enhanced methane recovery process and then field tested the method in a pilot project. They hold a patent on the process.

- The second method uses the injection of carbon dioxide (CO2) to displace methane from coal seams. Carbon dioxide is more strongly adsorbed on coals than both nitrogen and methane in coals and so it displaces methane by better adsorption. As an added benefit, this process also helps sustain the total system pressure.

Conventionally, water removal as of coal seams facilitates methane desorption according to the pressure-gas content relationship of its Langmuir isotherm, that is, total pressure is reduced to desorbs methane. The desorption , however, is a function of partial pressure instead of total pressure for a binary or multicomponent gas environment. Based on the Amoco process, as methane is swept away as of the adsorption site by nitrogen, it was found that the partial pressure of methane might be reduced more rapidly and to a greater extent than the total pressure by water removal. The end result according to the Langmuir isotherm is the same, but the partial pressure reduction by injecting nitrogen will be faster and attain a lower partial pressure of methane while maintaining the positive effects of a high total pressure on permeability.

Laboratory experiments show a 90%+ recovery of methane as of the flowing of two pore volumes of nitrogen in a crushed Jagger coal at 104°F.

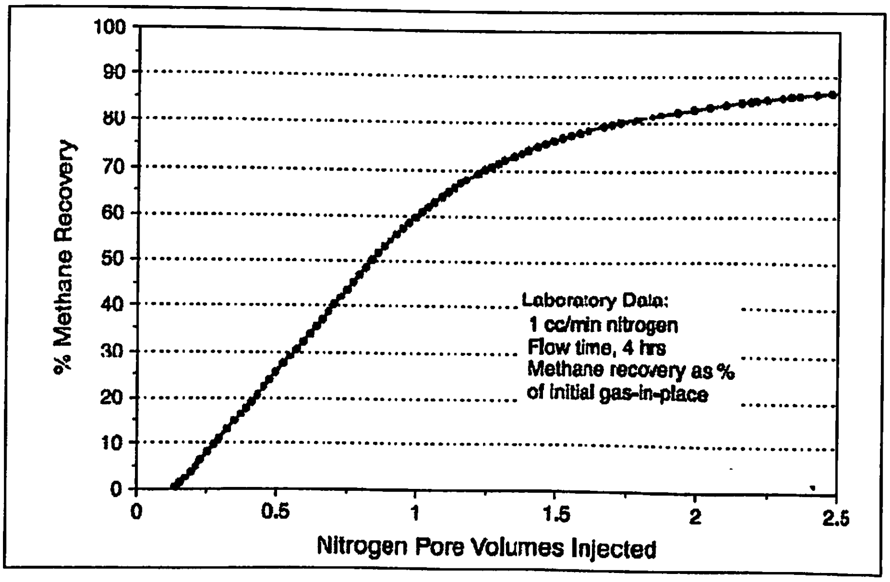


Fig. 4.1—Enhanced recovery of methane from coal

Another important potential of the process accrues as of the maintenance of a high total pressure as of injecting nitrogen or carbon dioxide throughout production. By maintaining the high pressure, lower stress is maintained throughout production, and higher permeability's are realized. Closure of the fissures in the coal by a progressively increasing effective stress is avoided.

It is important to understand the treatment response for these two processes when planning for enhanced CBM (ECBM) recovery. With nitrogen injection, the initial recovery rate is higher, but the breakthrough time of N2 is also earlier, hence, nitrogen must be separated as of the produced gas for a longer period of time. With CO_2 injection, the initial recovery is lower but the total recovery of original gas in place is earlier than with nitrogen. The breakthrough of CO_2 is delayed when compared to nitrogen because the affinity for CO_2 is very high in coals and so carbon dioxide moves through the coal bed very slowly. This increases the production of methane-rich gas for a longer time interval and reduces the amount of separation required. A coal bed's affinity for carbon dioxide makes it a viable candidate for CO_2 sequestration and this also helps enhance the methane production. The dual function of CO_2 injection has caught the attention of the U.S. Department of Energy (DOE), which has sponsored several research projects in this area.

Two commercial ECBM recovery projects have been implemented in the San Juan basin, namely at the Allison and Tiffany units.

Allison unit is operated by Burlington Resources, and they injected CO_2 into the Fruitland coals. The objective here is to recycle the CO_2 produced as of the Fruitland coals at the same time increasing the methane production as of coals. Approximately 4.7 Bcf of CO_2 has been injected continuously into the coals for more than 5 years. Of the 4.7 Bcf that has been injected, 4.2 Bcf of CO_2 has sequestered. In the project, the ratio of CO_2 injection to methane production was 3.1:1.0, which resulted in total incremental methane recovery of 1.5 Bcf.

Tiffany unit is located in the south-western part of LaPlata County, Colorado in the San Juan basin and is operated by BP America. A pilot project was commenced to understand the effects of nitrogen injection into the Fruitland coals in an area of approximately 10,000 acres. It consisted of 36 production wells and 12 injection wells. The injection was started in February 1998 and continued intermittently until it was suspended in January 2002. Nitrogen for injection came as of a cryogenic air separation plant in BP's Florida River gas processing facility northwest of the Tiffany unit. It was reported that the increase in methane production was approximately five-fold because of the nitrogen injection. However, early nitrogen breakthrough was observed in almost all the production wells. Approximately 20% cut was reported in all but one well after the first year of injection, causing the need for separation.

The net result of a nitrogen-injection enhanced CH_4 recovery process might be faster recovery of a larger ultimate CH_4 reserve. The process might be economical if the value of additional methane produced earlier exceeded the higher cost of process implementation, such as nitrogen injection and separation of the product gases. Carbon dioxide ECBM pilot projects are underway in Canada, China, and Poland indicating an added interest in this method because of the need for sequestering CO_2. The main obstacle to the ECBM process is increased uncertainty regarding economics of CO_2 injection, transportation, and separation processes rather than the operational costs at the wellheads. Once these issues are addressed via research, more and more operators will consider using this option.

4.2 Enhanced coal bed methane recovery using CO_2 Injection

Enhanced coal bed methane recovery is a method of producing additional coal bed methane as of a source rock, similar to enhanced oil recovery applied to oil fields. Carbon dioxide (CO_2) injected into a bituminous coal bed would occupy pore space and also adsorb onto the carbon in the coal at approximately twice the rate of methane (CH_4), allowing for potential enhanced gas recovery. This technique may be used in conjunction with carbon capture and storage in mitigation of global warming Whereas the carbon dioxide that is sequestered is captured as of the output of fossil fuel power plants.

The coalification process in coal seams generates coal, water, carbon dioxide (CO_2), and methane. The by products are stored in both the fracture space (generated by the shrinkage of the source plant material) and is adsorbed on the surface of the coal. Methane is preferentially stored on the coal surface. Carbon dioxide is pumped into the coal seam to displace methane.

Physical and chemical properties of coal:

-Adsorption/desorption of CO_2

-Interaction with SO^x and NO^x

-Absolute and relative permeability

-Swelling behaviour as of CO_2 adsorption.

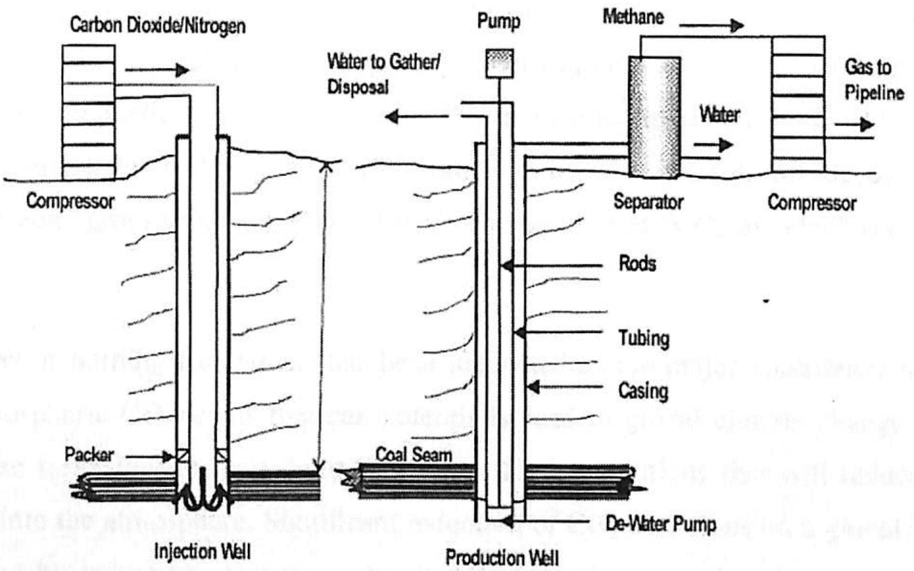


Fig 4.2 Gas is injected in one well and methane is recovered in another well

The ECBM process involves drilling a set of wells into the coal seam, one for injection of the oxidants and the other well at some distance away to bring the product gas to the surface.

Pure carbon dioxide is not injected. It can be mixed with Nitrogen.For two reasons: there may be a synergy of production mechanisms, and its use would result in the lowering of CO_2 levels in the mine air.

Deep unmineable coal formations provide an opportunity to both sequester CO_2 into coal seams and increase the production of methane Whereas the adsorption of CO_2 causes the desorption of methane.

Enhanced Coal bed Methane Recovery (ECBM) is presently not commercial due to the high cost of compression and capture of the injection gas either carbon dioxide (CO_2) or nitrogen (N_2). Recently, the necessity to reduce greenhouse gas emissions has provided a dual role for coal beds - as a source of natural gas and as a repository for CO_2. The second role arises because of the storage mechanism for gas in coal. Unlike CO_2-enhanced oil recovery processes, CO_2 injected during ECBM recovery is strongly adsorbed onto the coal, and in a relatively homogeneous reservoir is not expected to break through to the production wells until the bulk of the coal bed methane (CBM) reservoir is swept of methane. This provides a huge CO_2 storage potential in coal beds throughout the world. However, based on current economic factors, it makes more sense to partially deplete the coal reservoir of methane before injecting CO_2. The exact strategy depends on two economic factors, the costs and credits for sequestration of CO_2 and the natural gas sales price. CO_2 credits would have a major effect on the production strategy used for CBM, and would favour early use of ECBM. An example is used later in this paper to illustrate this point that takes into account the differences between "gross CO_2" sequestered (CO_2 captured), and "CO_2 avoided" (net CO_2 sequestered).

CO_2 emission as of burning fossil fuels has been identified as the major contributor to the increase in atmospheric CO_2 levels that can potentially lead to global climate change. The challenge for the fossil fuel industry is to find cost-effective solutions that will reduce the release of CO_2 into the atmosphere. Significant reduction of CO_2 emissions on a global scale may be achieved by reduction of energy intensity, by reduction of carbon intensity, or by capture and storage of CO_2. A portfolio of these methods is required to achieve the large reduction required, in which the utilization of carbon dioxide sinks will play an important role. Carbon dioxide sinks can be grouped into three broad classes based on the nature, location, and ultimate fate of CO_2.

Injection of carbon dioxide into deep coal seams has the potential to enhance coal bed methane recovery, while simultaneously sequestering a greenhouse gas. Analysis of production operations as of the world's first carbon dioxide-enhanced coal bed methane (CO_2-ECBM) pilot, a 4-injector/7-producer pattern in the San Juan Basin, indicates that the process is technically and economically feasible. To date, over 2 Bcf of CO_2 has been sequestered with negligible break rough. Enhancement of gas production can be as high as 150% over conventional pressure-depletion methods. Dewatering of the reservoir is also improved. ECBM development may be profitable in the San Juan basin at wellhead gas prices above $1.75/Mcf, adding as much as 13 Tcf of additional methane resource potential within this mature basin.

The key reservoir screening criteria for successful application of CO_2-ECBM include laterally continuous and permeable coal seams, concentrated seam geometry, and minimal faulting and reservoir compartmentalization. Operational practices for CO_2-ECBM recovery are still being refined. Injection wells should be completed unstimulated, while production wells can be cavitated or hydraulically stimulated. CO_2 injection should be continuous and concurrent with methane production to prevent lateral water encroachment. Apart as of the San Juan basin, many other coal basins have significant CO_2-ECBM potential. In the U.S., the Uinta and Raton basins are geologically most favorable, while additional potential exists in the Greater Green River, Appalachian and other coal basins. Coal basins in Australia, Russia, China, India, Indonesia and other countries also have large CO_2-ECBM potential. When viewed as of a commercial project viewpoint, the total worldwide potential for CO_2-ECBM is estimated at approximately 68 Tcf, with about 7.1 billion metric tons of associated CO_2 sequestration potential. If viewed purely as a non-commercial CO_2 sequestration technology, the worldwide sequestration potential of deep coal seams may be 20 to 50 times greater.

4.3 Economics of Coal bed Methane Recovery

The profitability of coal bed methane (CBM) project is highly dependent on factors of seam thickness, gas content, and permeability. Its economics are influenced by other variables, such as depth, water disposal volumes, access to market, and gas price. Well tests, logging, and core analyses add to the costs in regions without prior coal mining or core analyses of the coal.

The San Juan basin has proved to be the most profitable of any coal basin because two favourable factors, gas content and permeability combine there with thick seams. In the San Juan basin, the completions in its single 50-ft thick seams have been more cost-effective than completions in multiple, thin seams of the Appalachian and the Warrior basins. As another example of profitable

In the Warrior basin, favourable combinations of rank, permeability, and gas content exist. Property access, market access, moderate depths, and abundant data as of previous years of mining and conventional drilling compensate for thin seams to give success. Although more properties are marginally profitable because of thin seams in the Warrior basin, research (mostly as of support of the Gas Research Institute of the Rock Creek research site) has helped sustain economical production by developing fracturing, multizone completion techniques, computer simulations, well spacing, and water handling techniques to reduce costs and improve gas production.

Whatever combinations of reservoir parameters exist, high initial costs will be encountered in developing CBM properties. Unlike developing a conventional gas field, a CBM venture requires drilling a group of wells where interference between them will improve overall gas production by facilitating the more rapid removal of large volumes of water. A large capital investment is needed to develop a field.

It is understandable that the Section 29 tax credit established by the federal government assisted in the early development of the process, especially in the Warrior and Appalachian basins where some marginal properties became attractive with the credit. Moreover, Section 29 provided the impetus for the CBM process to be established. Since then, technical advances have improved the economics of the process, and technology holds the best hope for process viability in the future.

4.3.1 Measures of Profitability

Many factors are necessary to make a CBM property profitable and attractive for investment. Access to pipelines, proximity to markets, ownership certainty, infrastructure of oilfield services, and local regulations on water disposal impact a CBM property's profitability and are specific to a region to be estimated on an individual basis.

For multiple, thin seams similar to the ones of the Pennsylvanian Age in the eastern United States, critical parameters for development are gas content, permeability, and pressure. A discussion reiterating the importance of each follows.

Gas content of the coal must be sufficient to justify the expenses of developing. For profitable development in the Appalachian and Warrior basins, a minimum gas content of the coals is 125–150 scf/ton. Because of nonuniformities in coal rank and of ash content within a field, representative sampling is needed to give a reliable estimate of gas content in a property. For example, the River Gas Corporation obtained 31,844 ft of core before developing its 32,480 acres in Tuscaloosa County, Alabama.

A permeability of at least 0.1 to 0.5 md is needed for the eastern coals to be economically attractive. Above the threshold values, hydraulic fracturing may be used to enhance production rates.

4.3.2 Costs

Drilling and Completion

In general, the well costs—including drilling to a typical depth of about 3,000 ft in the Warrior basin, perforating, and fracturing three zones—amount to $190,000 to $200,000. The cost to drill, perforate, fracture, dispose of water, and bring the methane on stream of a Black Warrior development well 3,500 ft deep is estimated to be $319,300.5 The cost of a typical well of the River Gas Corporation in Tuscaloosa County, Alabama, is broken down in Table 5. The cost of drilling, completing, and gel fracturing a single zone of the Mary Lee/Blue Creek in the Oak Grove field was $125,000. In the San Juan basin, the open hole cavitation process costs $8,000–$10,000 per day to create the cavity. An average well cost in the San Juan basin is approximately $500,000, which includes installations at the surface; the figure also includes the monthly operating costs and the water disposal.

Table 5—Typical Costs of Tuscaloosa County Well

Typical Well Expenditure Item	Average Well Cost ($)
Intangible costs	101,000
Equipment	67,000
Geological/transportation/pipeline	6,000
Overhead	13,000
Total	**190,000**

Perforating evolved into the accepted completion procedure to access the formation for multiple-seam wells in the Black Warrior basin and to give maximum control over the initiation of hydraulic fractures. The choice is based on a procedure long used in the oil and gas industry that workers in the field can accomplish in a reproducible manner and in a short time. A major consideration in the eventual selection of perforating, however, was a lower cost than slotting or open hole completions. Lambert estimated the relative costs of the three completion procedures given in Table 6. The higher costs of the open hole and slotting procedures go along with less reliability and more lost time than perforating. Thus, perforating may cost 45% of open hole completion or 68% of the slotting procedure costs.

Table 6—Relative Costs of Completion Methods

Openhole Item[a]	Openhole Cost ($)
Top packer for 8-in. diameter hole, minimum rental	2,688.00
Bottom packer for 8-in. diameter hole, minimum rental	2688.00[b]
Supervision, 2 hr at $60/hr	120.00
Total	**5,496.00**
Perforating Item[c]	**Perforating Cost ($)**
Service charge	500.00
Rig time, 2 hr at $120/hr	240.00
Perfs, 16 at $36.75/3 each	588.00
Supervision, 2 hr at $60/hr	120.00
Retrievable bridge plug	980.00
Total	**2,428.00**
Slotting Item[d]	**Slotting Cost ($)**
Sand, 20/40-mesh, 100 sks at $6.00 each	600.00
Water hauling, 5 hr at $40/hr	200.00
Rig time, 2 hr at $120/hr	240.00
Sand transport (100 sks)	340.00
Jet tool (double stack) rental	750.00
Jets, 4 at $43 each	172.00
Supervision, 4 hr at $60/hr	240.00
Abrasive fluid charge, $.25 × 100 sks	25.00
Retrievable bridge plug	980.00
Total	3,547.00[e]

[a] Isolated 4-ft interval.

[b] Backfilling the hole with sand is an alternative method to provide lower isolation. The costs associated with removal of such sand is considered equivalent to the bottom packer rental cost quoted.

[c] 4 SPF, 61-in. EHD, 4-ft interval

[d] 4-ft slot, 1 coalseam frac

[e] No service equipment or related standby or mileage considered. No rig trip time or related standby considered. Actual costs on individual slotting jobs are estimated at $5,000, if not performed in conjunction with the hydraulic stimulation process.

Finding Costs

Reserves and production rates for wells in the San Juan basin are higher than in the Warrior or other eastern basins. The differences are emphasized by comparing finding costs in the two basins. Hobbs presented the comparison as recorded in Table 7.

Table 7—Finding Costs of Basins

Basin	Reserves Per Well (Bcf)	Find Costs ($/Mcf)
San Juan	0.4 to 9.0	0.08 to 0.24
Black Warrior	0.3 to 1.2	0.28 to 0.67

Chapter 5

CASE STUDY 1: FIELD-TESTING CO_2 SEQUESTRATION *AND* ENHANCED COALBED METHANE RECOVERY IN ALBERTA, CANADA – A HISTORICAL PERSPECTIVE AND FUTURE PLANS

5.1 INTRODUCTION

The coal bed methane (CBM) recoverable resources in the Plains and Foothills regions of the Western Canada Sedimentary Basin (WCSB) are estimated to be 135 to 261 trillion cubic feet (TCF) and are comparable to the marketable conventional gas endowment of 263 TCF. About 48.5 mega tonnes (Mt) or 32% of the **151** Mt of CO_2 emissions generated in Alberta in 1996 originated as of coal-fired power plants (Fig 1).

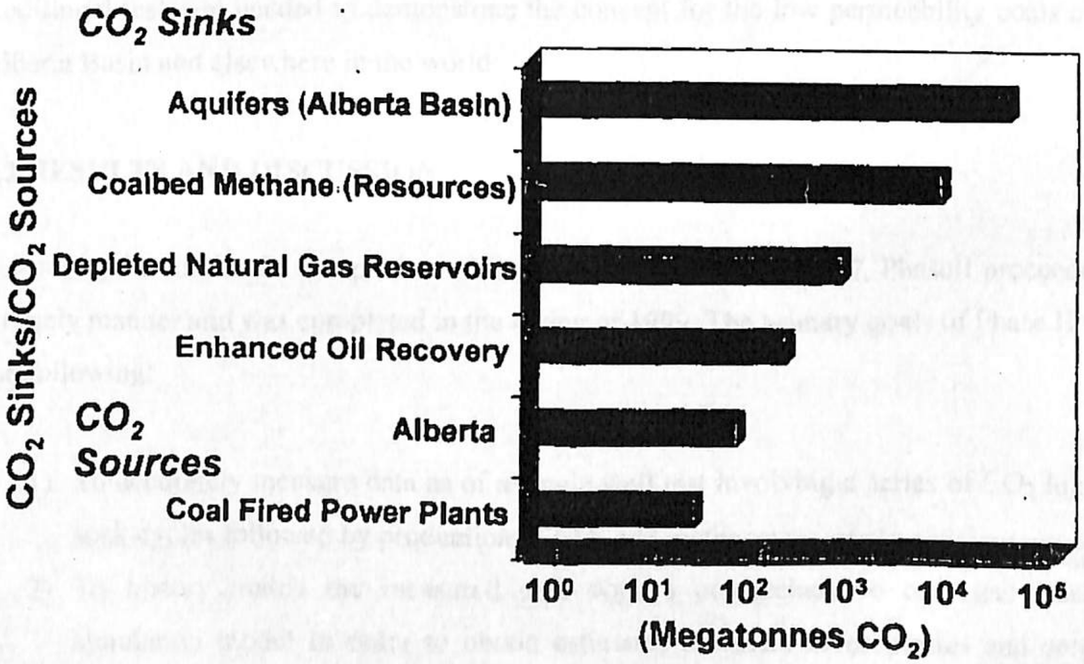


Figure 5.1 Emissions and greenhouse gas storage capacity in the Alberta basin.

The above figure also shows that coal beds in the Alberta part of the WCSB are second only to aquifers in terms of storage capacity for CO_2 .An abundance of deep and unminable coal seams in Alberta makes geological storage of CO_2 applicable, particularly in those areas located in close proximity to power plants emitting large quantities of CO2, a greenhouse gas (GHG). In such a storage process, the co2 produced as of the power] plants might be injected into the coal seams to produce CBM. This might lead to null- GHG power plants that would be fuelled by methane released as of the deep coals in a cyclical approach that would eliminate any release of CO_2 to the atmosphere.

The Alberta Research Council is currently leading a multi-phase study on field-testing CO_2 enhanced CBM recovery at a site near Fenn Big Valley, Alberta, Canada. Phase I encompassed a paper study of the initial assessment and proof of concept of injecting CO2, nitrogen, and flue gas into Mannville Group coals (Lower Cretaceous age) in the Alberta Basin. Phase II concentrated on the design and implementation of a CO_2- micro pilot test following procedures developed by Amoco Production Company for coals in the San Juan Basin in the U.S. The project is now in Phase III which is to estimate the design and implementation of a full-scale pilot project. Burlington Resources has successfully injected CO_2 into relatively high permeability coal seam in the San Juan Basin and stimulated CBM production and recovery rates compared to primary production (a pressure depletion process). Additional tests are needed to demonstrate the concept for the low permeability coals of the Alberta Basin and elsewhere in the world.

5.2 RESULTS AND DISCUSSION

Following the successful completion of Phase I in the summer of 1997, PhaseII proceeded in a timely manner and was completed in the spring of 1999. The primary goals of Phase II were the following:

1) To accurately measure data as of a single well test involving a series of CO_2 injected soak cycles followed by production of CO_2 and methane;
2) To history match the measured data with a comprehensive coal gas reservoir simulation model in order to obtain estimates of reservoir properties and sorption characteristics; and
3) To calibrate simulation models To predict the behaviour of a large scale pilot project or full field development.

The field test was carried out in an existing Gulf Canada well at the Fenn Big Valley location in the central Alberta Plains. Phase II was, in essence, the prelude to a full-scale 5-spot pilot test. The study concluded that a full-scale pilot CO_2 sequestration ECBM (enhanced coal bed methane recovery) project is possible in the above location.

The economic feasibility analysis of Phase II revealed that flue gas injection offers better economic return than pure CO_2 injection unless there is credit for the CO_2 avoided. At a rate of US$ 1.00 per thousand standard cubic feet (MSCF) of CO_2 (US$19 per Tonne), the CO_2 would account for US$ 2.00 per MSCF of methane sold, assuming that it takes at least 2 cubic fset of CO_2 injected for each cubic feet of methane produced. The CO_2- ECBM recovery mechanism is shown in Figure 2 (4-5).

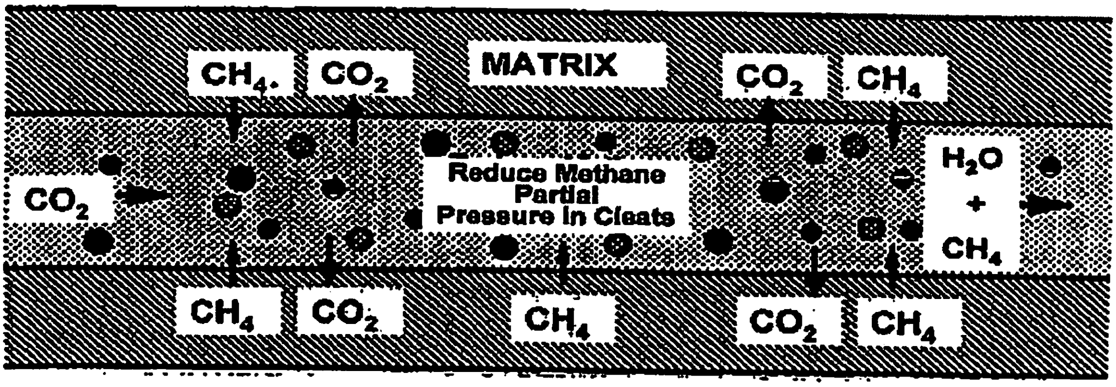


Figure 5.2 CO_2-enhanced coal bed methane recovery mechanism.

It might be advantageous to optimize the CO_2 /N_2composition of the flue gas when considering CO_2 storage/sequestration options. If flue gas is injected, the CO_2 would remain sorbed in the coal matrix while the majority of N_2, by being adsorbed less than CO_2, would be produced along with the methane. Flue gas injection would enhance CBM production rates by more than a factor of two. However, the early breakthrough of N_2 at the production well will cause an additional expense of having To separate N_2 as of methane for sales. Pressure swing adsorption (PSA) systems are the optimum method to remove N_2 as of the produced gas for small- scale /large N_2 content operations whereas cryogenic processes are favoured for large field operations. Flue gas conditioning, compression, and N_2/CH_4 separation in surface facilities remain some of the technical challenges that will be addressed in Phase III. Therefore by combining CO_2 and N_2 for injection, the appearance of N_Z will be retarded compared to a pure N_2 injection stream and the methane production rate will be enhanced compared to a pure CO_2 stream. However, gas separation will play a key role in the production of methane as of coal beds and the most economic gas separation method for the injection gas stream will depend on the specified CO_2 concentration of this stream.

The three numerical models that were estimated in Phase II adequately predicted the primary production of CBM. One such simulation, based on a 5 spot, 320-acre pattern, showed that CH_4 production rate increased by a factor of about 5 compared To primary production when flue gas was injected but methane production decreased rapidly (Figure 3).

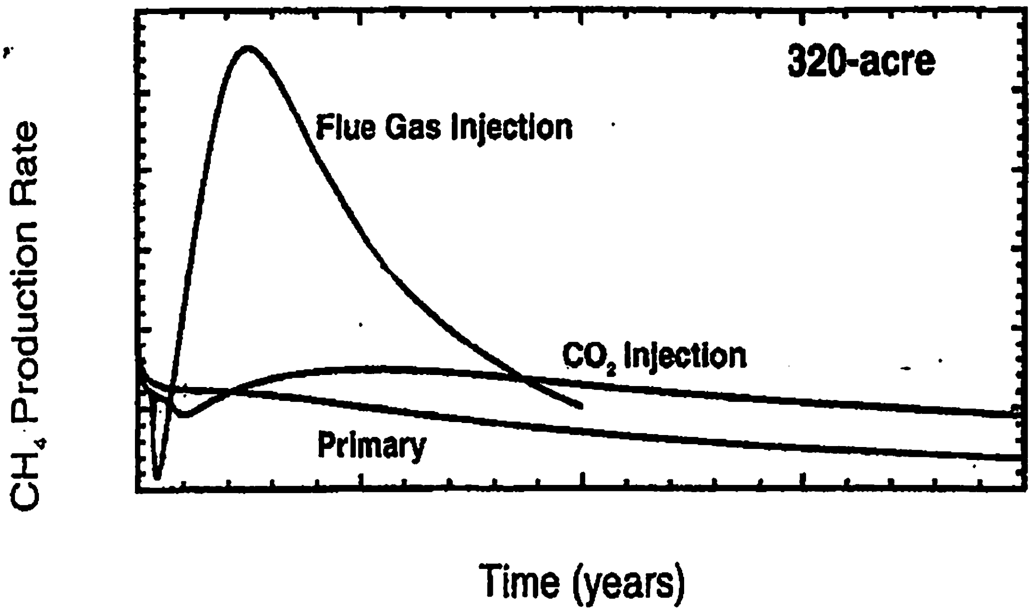


Figure 5.3 Coal bed methane production rate over time for primary recovery and as a result of pure CO_2 and flue gas injection.

On the other hand, pure CO_2 injection resulted in methane production at lower rates but for much longer periods of time. Only one out of the three models estimated was suitable To simulate flue gas injection. None of the three simulation software packages were capable of predicting the produced gas composition in the field test with any degree of accuracy. A better understanding of the process mechanisms involved, for example multiple gas sorption and diffusion, and changes in coal matrix volume due To sorption/desorption of gases is needed to guide any future development of the models.

Phase III was divided in two parts, To be conducted in stages as of 1999 To 2001. Phase III-An estimated the options for the treatment of flue gas, compression and associated economics to optimize CO_2 storage and CBM recovery both at the pilot and commercial scales. A second well was drilled and completed in the fall of 1999. Two flue gas micro pilot tests, first of this kind in the world that involve injection of flue gas into a coal seam were carried out. Initially, core samples were taken as of the second well and estimated To calculate the gas-in-place volume, gas composition, and gas storage capacity. The micro-pilot test was performed in the spring of 2000 by injecting a simulated flue gas steam consisting of two different ratios of N_2 and CO_2 to obtain greater methane recovery without any hindrance to CO_2 storage. The data will be used to finalize the design of the full-scale project that will be implemented in Phase III-B.

Phase III-B encompasses the implementation of a 5-spot field pilot, which would consist of four injection wells and one production wells, sized in a rectangular pattern between 20 and 40 acres. The objective of this phase would be to demonstrate the viability of a large-scale CO_2 storage/ECBM project and to obtain information on the specifications of the technology required to perform a full-scale development project. These specifications will be used To design flue gas collection and treatment facilities, compression, and gas production/separation facilities. The current plans call for the 5-spot pilot To be performed in the Fenn Big Valley site. Three additional wells will be drilled in 2001. These wells, along the one drilled in 1999 and the existing Gulf Canada well will comprise the 5 wells needed for the large pilot. Injection will begin in 2001 and will continue for 12 months.
If the large-scale pilot is successful, full-scale development might begin in 2003 either on the above site or at another suitable location in the Alberta Basin. Although most of the work so far has focused on the Manville Group coals in the Fenn Big Valley area, a parallel study conducted by the Geological Survey of Canada estimates the geological properties of other unminable coal seams in Alberta, such as those of the Edmonton and the Ardley groups (Upper Cretaceous-Lower Tertiary). The Edmonton coals are shallower than the Mannville coals and are located in closer proximity to major coal-fired power plants, thus making these coals favourable targets for COZ storage. On the other hand, the Ardley coals are being investigated because of their higher permeability and lower injection pressures and costs required for a successful pilot.

5.3 CONCLUSION

In conclusion, flue gas injection into coal bed reservoirs has scientific merit and is more economical than pure CO_2 injection for ECBM recovery purposes.. More work is needed on the gas treating, compression, and injection methods in order To allow US To calculate the economics between CO_2 storage and methane production from coalbeds.

CASE STUDY 2: COAL-SEQ PROJECT UPDATE: FIELD STUDIES OF ECBM RECOVERY/CO2 SEQUESTRATION IN COALSEAMS

5.4 INTRODUCTION

The Coal-Seq project, funded by the U.S. Department of Energy and being performed by Advanced Resources International (ARI), is investigating the feasibility of CO_2 sequestration in deep, unmineable coal seams, by performing detailed reservoir studies of two enhanced coal bed methane recovery (ECBM) field projects in the San Juan basin which are undergoing CO_2 and N_2 injection. The interest in understanding the N_2-ECBM process has important implications for CO_2 sequestration via flue-gas injection. The project is also conducting supporting studies into the effects and modelling of multi-component sorption and coal swelling. This paper describes the results and findings as of the project through mid-2002.

5.5 Field Results

The field R&D sites are located in Colorado and New Mexico (Figure 5.4). At Allison, CO_2 is being injected, and the CO_2 is sourced as of a nearby pipeline that transports CO_2 as of the Cortez area of New Mexico To West Texas for CO_2 flooding of oil reservoirs. The Tiffany project, into which N_2 is being injected, the N_2 is sourced as of an air separation plant located at BP's Florida River gas processing facility.

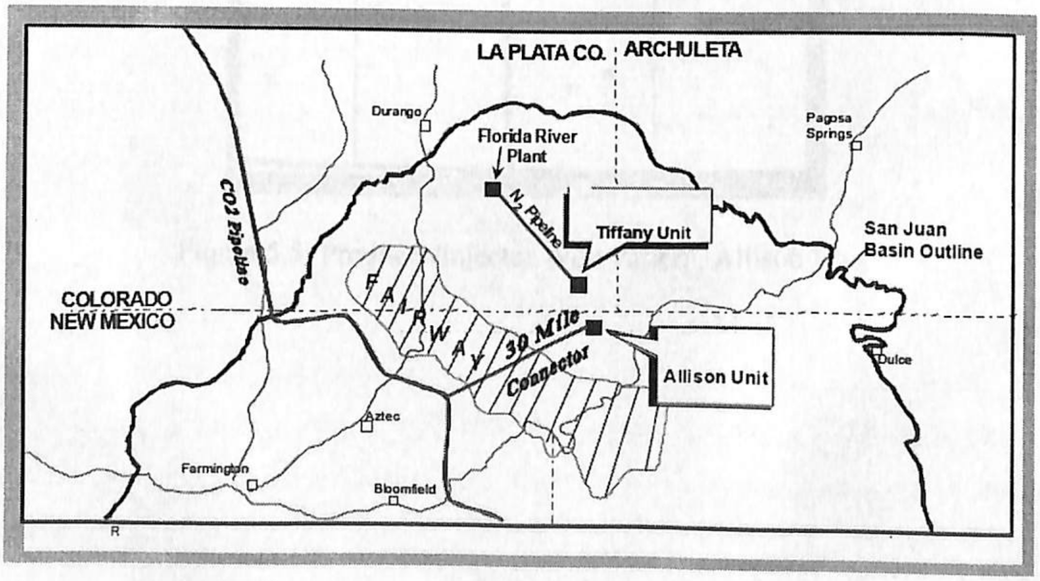


Figure 5.4: Location of Field Sites, San Juan Basin

Allison Unit

The Allison Unit study area consists of 4 CO_2 injector wells and 9 methane producers (Figure 5.5). The field originally began production in 1989, with CO_2 injection beginning in 1995. CO_2 injection operations were suspended in mid-2001 to estimate its' impact on field methane recovery. The production/injection history for the field is illustrated in Figure 5.6. Note that for a period following the commencement of injection operations, other production enhancement activities were also performed, such as recavitations, well reconfigurations and the installation of dewatering pumps, line pressure reductions, and the implementation of on-site compression.

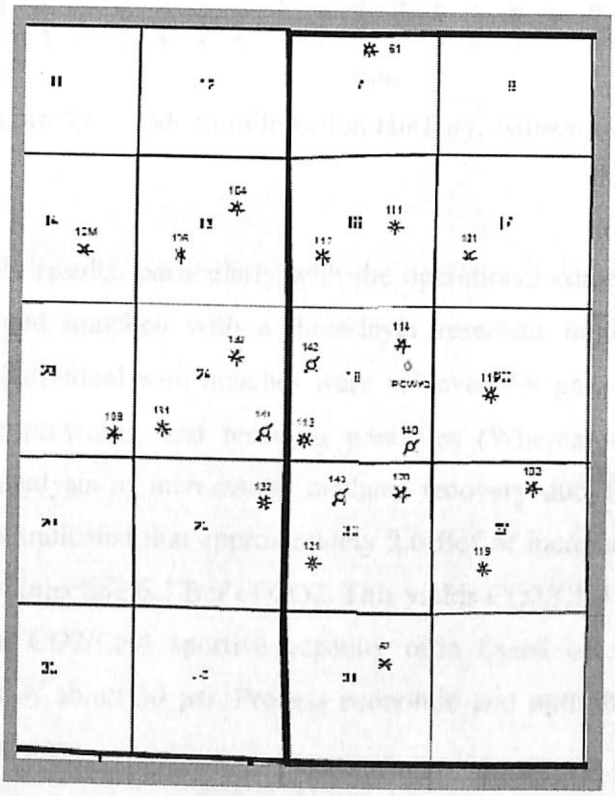


Figure 5.5: Producer/Injector Well Pattern, Allison Unit

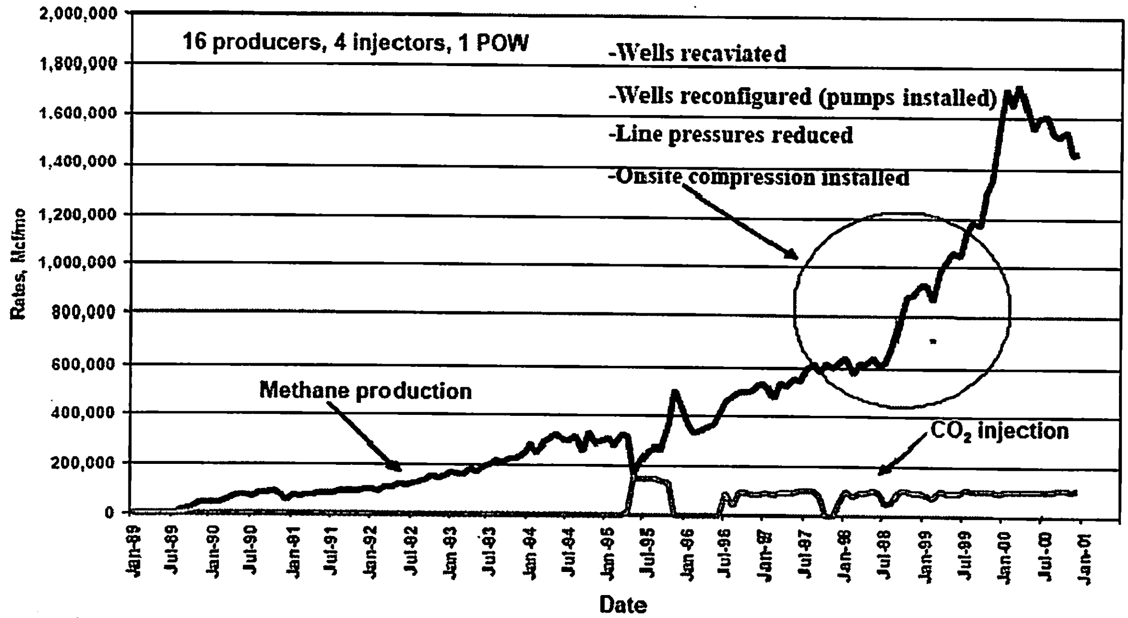


Figure 5.6: Production/Injection HisTory, Allison Unit

To understand the field results, particularly with the operational complexity that exists, the field was simulated and matched with a three-layer reservoir model, and using ARI's COMET2 simulator. Individual well matches were achieved for gas rate, gas composition, water rate, producing pressures, and reservoir pressures (Whereas available). Using the calibrated model, an analysis of incremental methane recovery due To CO2 injection was performed. The results indicated that approximately 2.0 Bcf of incremental methane will be recovered as a result of injecting 6.3 Bcf of CO2. This yields CO2/CH4 ratio of 3.2; this ratio is consistent with the CO2/CH4 sportive capacity ratio based on the isotherms at the abandonment pressure of about 50 psi. Process economic and optimization studies for the field are currently underway.

Tiffany Unit

The Tiffany Unit study area consists of 12 N_2 injector wells (10 of which are directional) and 34 methane producers (Figure 5.7). The field originally began production in 1983, with intermittent N_2 injection beginning in 1997. The production/injection history for the field is illustrated in Figure 5.7.

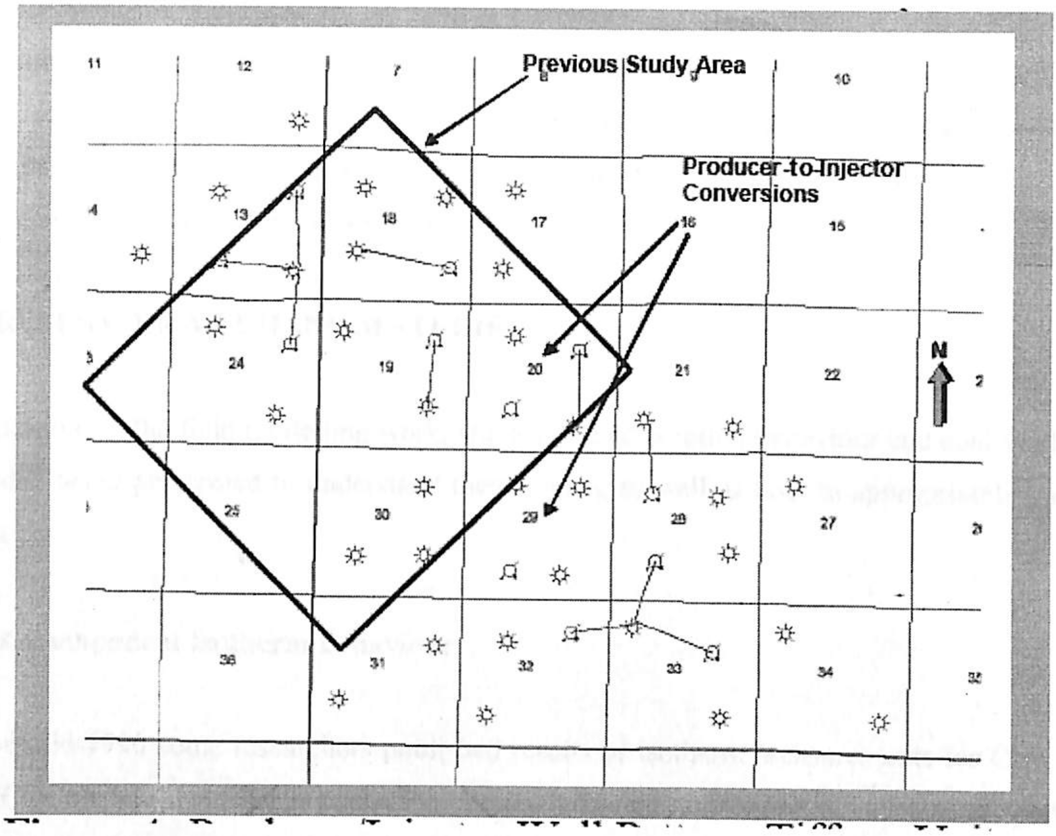


Figure 5.7: Producer/Injector Well Pattern, Tiffany Unit

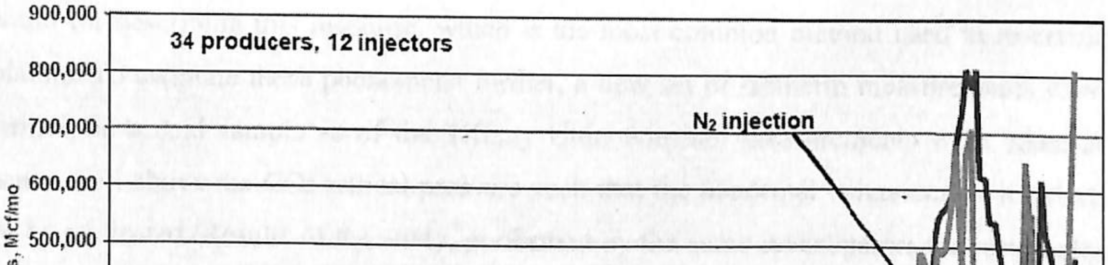


Figure 5.8: Production/Injection HisTory, Tiffany Unit

To understand the field results, the field is being simulated and matched with a four-layer reservoir model, and using ARI's COMET2 simulator. Individual well matches are being achieved for gas rate, gas composition, water rate, producing pressures, and reservoir pressures (Whereas available).Once complete, incremental recovery and process optimization and economic analyses will be performed.

5.6 RESERVOIR MECHANISM STUDIES

In addition To the field modelling work, studies of coal sorption behaviour and coal swelling are also being performed to understand their impact, as well as how to appropriately model them.

Multi-Component Isotherm Behaviour

In the mid-1990 some researchers published results of isotherm measurements for CH_4, N_2, and CO_2 on San Juan basin coal. The results indicated an abnormal increase in sportive capacity for CO_2 around the CO_2 critical pressure. Several different theories on the cause for the abnormal behaviour have been proposed, the most common of which is multi-layer adsorption. Importantly, the consequence of this behaviour is that the Langmuir equation is not valid for describing this response, which is the most common method used in reservoir simulators. To estimate these phenomena further, a new set of isotherm measurements were performed on a coal sample as of the Tiffany Unit. Sorption measurements were taken at pressures well above the CO_2 critical pressure such that the abnormal behaviour, if it exists, might be replicated. Results of the study, performed by the same investigators that originally performed and reported the abnormal behaviour, did not show the abnormal behaviour. It was discovered that an error in reducing the measured data to absolute sorption units, magnified by the closeness of the density in the gas and adsorbed phases near the critical point, was the source of the "abnormal" behaviour. (The investigators had identified the problem prior to this effort, but the absence of the behaviour was clearly established as a laboratory finding with this work.) Another, and perhaps just as important finding, was that while sorption models such as Langmuir can adequately describe sorption behaviour, no known model, Langmuir or otherwise, can accurately predict multi-component sorption behaviour based on single-component data. In general, the error is larger the greater the difference in adsorptive capacities for the gases, and is larger for the less-adsorptive gas.

Coal Swelling Behaviour

It is a well-established that as gas is released as of a coal reservoir, the coal matrix shrinks, and cleats open, creating a significant improvement in coal (cleat) permeability. There has been considerable speculation and some laboratory evidence that the process also works in reverse; that is, as gas is adsorbed onto coal, the matrix swells, cleats close, and permeability is reduced.

Since CO2 is much more adsorptive on coal than methane (by 2-3 times), the problem is exacerbated with CO2 injection. To examine this effect, as well as how to model it, the injection histories of the four CO2 injector wells at the Allison Unit were studied. Pressure transient test results for the wells were also available. Figure 5.9 presents the CO2 injection rate and computed bottom hole pressure for one of those wells. Initially, injectivity declined significantly. Subsequent To that, injectivity began a long period of improvement, which has continued through the last available data. These trends are consistent for all four of the injection wells.

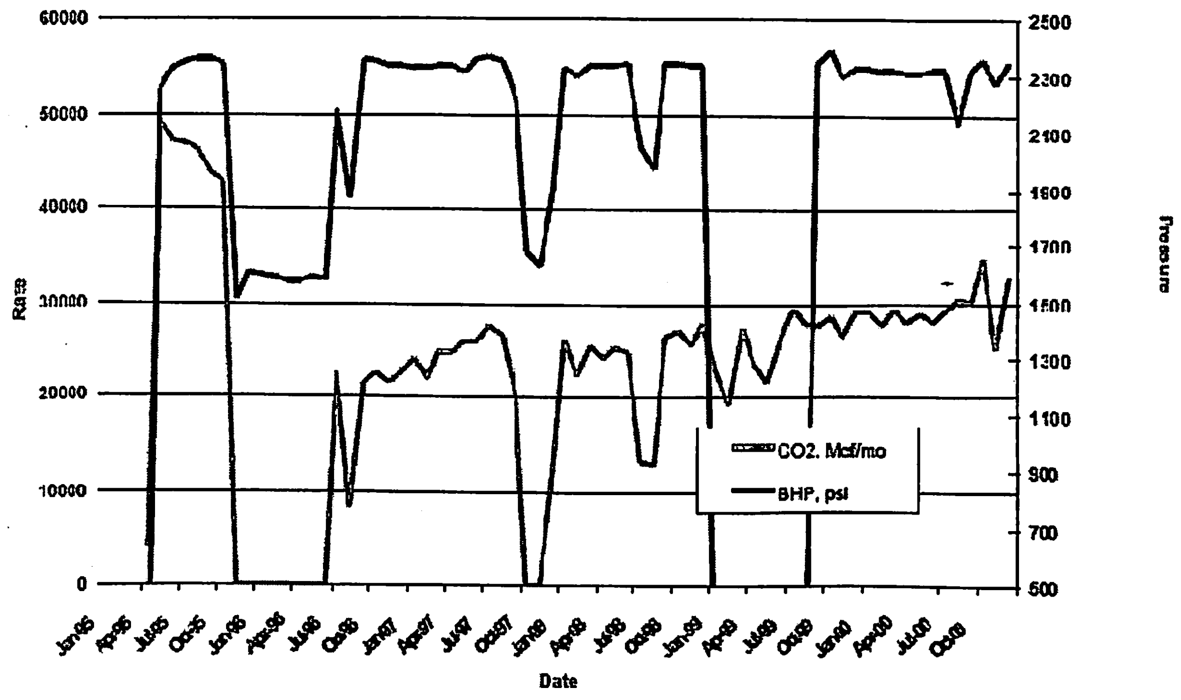


Figure 5.9: Injection/Pressure History for CO_2 Injection Well, Allison Unit

Pressure transient data as of several producing wells in the field in the vicinity of the four injector wells had been collected in May, 2000. The results of their analysis suggested that insitu coal permeability for the area was in the 100 – 130 md range. In August, 2001, the four injector wells were temporarily shut-in, and bottom hole pressure data collected. Results of analyzing these data suggested coal permeability's in the >1 md range, two orders of magnitude less than the implied initial values, a reduction of 99%. These data provide our first insight into the potential magnitude of coal permeability reduction with CO2 injection on a field-level basis. Using the ARI permeability function model, the permeability history of the injector wells was rationalized. This is illustrated in Figure 10. First, coal permeability at the injection well locations declined with a reduction in pore pressure. When the injection wells were drilled and injection commenced, a rapid reduction in permeability occurred as the permeability trend shifted as of the methane To the CO_2 curve. Later in injection well history, as the area under injection became further depleted and reservoir pressures declined, matrix shrinkage began to occur, leading to a continuous and gradual improvement in the injectivity. While somewhat subjective, this explanation is entirely consistent with field data, the results of reservoir simulation studies, and the predicted response based on the permeability function model.

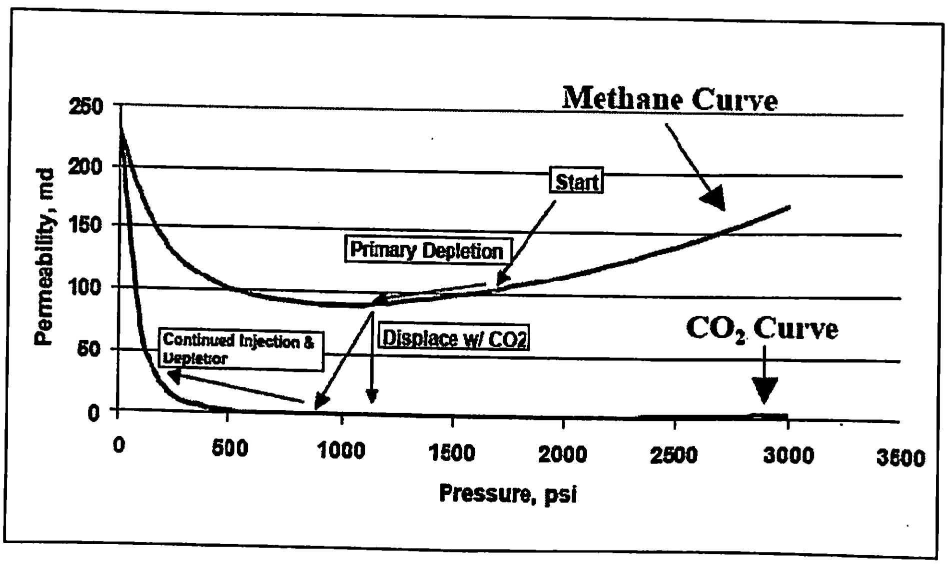


Figure 5.10: Permeability History for CO_2 Injection Well

Nomenclature

1. CBM – Coal Bed Methane
2. ECBM-Enhanced coalbedmethane Recovery
3. CMOP -Coal bed Methane Outreach Program
4. BTU/Scf- British Thermal Unit per Standard cubic feet
5. tcf - Trillion Cubic Feet.
6. k_{rg} = relative permeability to gas
7. k_g = effective gas permeability
8. k = absolute permeability as defined by Darcy's la
9. WF_{RMC} (weight-fraction) = residual moisture content
10. WF_{DASH} (weight-fraction) = dry ash content
11. W_{DAF} (grams) = weight of the dry, ash-free coal sample
12. GC_{DAF} (scf/ton) = gas content-dry, ash-free basis
13. ρ_{DAF} (gm/cm3) = density of coal, dry, ash-free basis
14. ρ_a (gm/cm3) = density of dry ash
15. ρ (gm/cm3) = density of dry coal containing ash
16. DASH (weight %) = dry ash content
17. W_{DAMSF} (grams) = weight of the dry, ash-residual moisture-sulfurfree coal sample
18. $W_{Air\text{-}Dry}$ (grams) = weight of the air-dry coal sample
19. WF_{RMC} (weight-fraction) = residual moisture content
20. $WF_{AR\text{-}ASH}$ (weight fraction) = as-received ash content
21. $WF_{AR\text{-}TSC}$ (weight fraction) = as-received total sulphur content
22. $GC_{In\text{-}situ}$ (scf/ton) = gas content-in-situ basis
23. GC_{PC} (scf/ton) = gas content-pure-coal basis
24. WF_{RMC} (weight-fraction) = residual moisture content
25. WF_{DASH} (weight-fraction) = dry ash content
26. WF_{DASH} (weight fraction) = dry ash content
27. ρ (g/cm3) = measured bulk density of coal
28. ρ_c(g/cm3) = density of "pure" coal
29. ρ_a (g/cm3) = density of ash
30. R_f= recovery factor
31. G_i = initial gas in place
32. G_R = methane recoverable reserves

33. R_f = recovery factor

34. V_i = initial volumetric gas content, scf/ton

35. V_a = abandonment gas content, scf/ton

36. q = producing rate at time t, vol/unit time

37. q_i = producing rate at time 0, vol/unit time

38. D = nominal exponential decline rate, 1/time

39. t = time

40. e = base of natural logarithms.

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