COALBED METHANE AND ITS RESERVE ESTIMATION

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COALBED METHANE AND ITS RESERVE ESTIMATION

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CERTIFICATE

This is to certify that the work contained in this thesis titled "Coalbed Methane and its Reserve Estimation" has been carried out by Neha Kala under our supervision and has not been submitted elsewhere for a degree.

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ABSTRACT

The need for exploration of nonconventional source of energy to bridge the ever increasing energy gap is felt all over the globe as the world production of oil and gas is likely to peak within the next twenty years and finding and exploiting new reserves at economic cost is becoming more challenging. Against the backdrop of scenario of dwindling oil reserve base, it becomes important to develop and strengthen the reserve base of gas for sustainable production in the coming decades. To augment the effort of searching out alternative energy sources, exploration and production of coal bed methane (CBM), natural gas hydrates, shale oil and gas and tar sands is being targeted in many countries.

The major project on "Coalbed Methane and it's Reserve Estimation" presents an understanding of reservoir engineering aspects of coalbed methane reserves and deals with the methods for quantifying the amount of gas in them. The main focus of the paper is on the generation of coalbed gases, the reservoir engineering aspects of coalbed seams and the estimation of coalbed gas content.

The report deals with the reservoir engineering aspects of reserves of **coal bed methane** gas. This is useful to understand how the reservoir properties of coal differ from those of conventional gas reservoirs, understand how these properties affect production from coalbed methane reservoirs and evaluate the reserve and production potential of coalbed methane. The report also covers procedures used for determining the gas-in-place volume of coalbed reservoirs. Gas-in-place is the volume of gas stored within a specific bulk reservoir rock volume. Accurate gas-in-place analysis is crucial to reliably evaluating coalbed gas exploration prospects, forecasting the gas production rates of coalbed reservoirs, and evaluating the potential severity of natural gas emissions during coal mining operations. Coalbed reservoir gas-in-place analysis is a very complex process. Four physical reservoir parameters are needed to calculate the gas-in-place volume: reservoir or well drainage area; gross reservoir rock thickness (consisting of both coal and other organic-bearing rock types); average reservoir rock density; and average in-situ gas

content. The concepts and procedures which apply to bituminous coals and other reservoirs dominated by adsorptive storage capacity rather than compressible storage in porosity have been studied. The purpose of this is to develop a clear understanding of the concept of measuring coal bed gas content, estimating the coal bed gas content, sorption, adsoption and estimating the loss of gas, present the most reliable technology for collecting and interpreting gas desorption data, provide practical methods for estimating coalbed gas content and explain the advantages and limitations of the methods. This part of the project provides background information needed to understand the basic theories and practices for determining coalbed gas content.

The report also deals with various methods used for determination of reserves of coalbed methane. The application of volumetric analysis and material balance equations is presented in the report.

Due to the increasing energy gap it is important that the importance of unconventional resources is realized. Work is required for clear understanding of the concepts to develop the sources in the most efficient ways. In case of coalbed methane the proper estimation of gas content is very important. Its analysis and reserve estimation of coalbed methane reserves is important for determining the feasibility of the project.

Acknowledgement

I would like to express my sincere thanks to University of Petroleum and Energy Studies for giving me opportunity to work on the project "Coalbed Methane and its Reserve Estimation" and to KDMIPE, ONGC, Dehradun for allowing me to do my laboratory studies in their organization and provide necessary guidance.

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NOMENCLATURE

V = volume, scf

A = drainage area, acres

h = thickness, ft

d = depth in meters

R_f= recovery factor

C_{gi} = initial sorbed gas concentration

C_{ga} = abandonment pressure sorbed gas concentration.

G_S = gas content

G_p = Cumulative gas production

W_p = Cumulative water production

q_1 = production rate at time t

q_0 = and cumulative producing time (t)

r_e = drainage radius

r_w = wellbore radius

k = permeability

S_{wi} = initial water saturation

B_{gi} = initial formation volume factor

ρ_B = bulk density of coal

W_e = water influx

P, T = pressure, Temperature

P_i = initial pressure

Z_i = compressibility factor at P_i

T_{SC} = temperature at standard conditions

P_{SC} = pressure at standard conditions

G_P = cumulative gas produced, scf

G = gas originally adsorbed, scf

G_F = original free gas, scf

G_A = gas currently adsorbed, scf

G_R = remaining free, scf

Ø = porosity, fraction

E_{gi} = gas expansion factor at p_i in scf/ bbl

V_m = Langmuir isotherm constant, scf/ ton

m = slope of curve

a = exponential decline constant

b = Langmuir pressure constant, psia^{-1}

c_w = isothermal compressibility of water, psia^{-1}

c_f = isothermal compressibility of the formation, psia^{-1}

SUBSCRIPTS

i = initial conditions

p = production

w = water

f = formation

1 = at time t = t

0 = at time t = 0

A = adsorbed

R = remaining

F = free

e = drainage

ga = sorbed gas at abandonment

gi = sorbed gas at initial condition

ABBREVIATIONS

OGIP = original gas in place

CGIP = current gas in place

STB = stock tank barrels

CBM = Coalbed Methane

CH_4= methane gas

CO_2 = carbon dioxide gas

N_2 = nitrogen gas

N_2O = nitrogen oxide

H_2S = hydrogen sulphide

-COOH = Carboxyl group

$-OCH_3$ = methoxyl group

FC = fixed carbon

VM = volatile matter

H_2O = water

daf = dry ash free

Bscf = billion standard cubic feet

Mscf = million standard cubic feet

COAL BED METHANE AND RESERVE ESTIMATION

Chapter: 01 - INTRODUCTION

Oil has been a major source of energy but because of the increasing gap between the demand and supply there is a steady shift towards gas as the major source of energy. Many sources of gas have now been considered that include both the conventional as well as the un- conventional sources.

1.1. Gas Reservoir Types

There is a variety of reservoir types with substantial differences due to the gas storage mechanism. These include conventional gas reservoirs, gas condensate reservoirs, unconventional gas reservoirs, coalbed gas reservoirs, and gas-bearing shale reservoirs.

1.1.1. Conventional Gas Reservoirs

In conventional natural gas reservoirs the gas molecules are stored by compression within rock pores. The gas in-place analysis is a straightforward volumetric calculation since the total gas volume within the reservoir is solely a function of the total pore space volume containing gas and the in-situ gas content within a unit volume of pore space. In general, there is no significant gas molecule-reservoir rock interaction, and the reservoir functions as a constant-volume tank, i.e., the rock porosity does not vary significantly as a function of pressure change. When natural gas is a constant composition fluid, i.e., does not undergo phase change upon reduction in reservoir pressure, the amount of natural gas stored by compression within a specified rock pore volume can be calculated using temperature, pressure and volume relationships derived from fundamental gas laws. Thus, the in-situ gas content is a direct function of the effective rock porosity, reservoir temperature and pressure, and gas composition. Because the pores of conventional reservoir rocks contain formation water, the water saturation must be estimated to determine the volume of gas within the porosity.

1.1.2. Gas-Condensate Reservoirs

At reservoir temperatures and pressures greater than 200 °F and 2,000 psia, respectively, natural gas can dissolve significant amounts of non-volatile hydrocarbons. If the non-volatile hydrocarbon concentration is greater than about 0.7 mole percent, the reservoir is referred to as a gas-condensate reservoir. Gas-inplace analysis is not straightforward for gas-condensate reservoirs and special engineering and operating methods are needed for maximizing gas recovery since the reservoir gas is not a constant composition fluid but separates into vapors and liquids upon pressure reduction.

1.1.3. Unconventional Gas Reservoirs

When rock pores contain liquid phase fluids such as brine or crude oil, some natural gas can be stored as an absorbed phase. The solubility of natural gas in brine and crude oil varies as a function of the reservoir temperature and pressure, the molecular properties of the liquid phase fluid, and the molecular properties of the gas constituents. If natural gas and water occur together within the pores of rocks in permafrost zones or outer continental shelf margin regions, the gas is stored by inclusion within solid, crystalline compounds called gas hydrates. The gas content of the hydrate phase varies as a function of the reservoir temperature and pressure, hydrate crystal structure, and the molecular properties of the gas constituents. A single cubic foot of methane hydrate can store as much as 164 standard cubic feet of methane gas. The in-place gas hydrate resources worldwide are estimated to total 6.6x105 Tscf. Worldwide, significant amounts of natural gas are stored by absorption in crude oil reservoirs (called dissolved or solution gas), in aquifer reservoirs (called brine gas), and in geopressured reservoirs (called geopressured gas). Brine gas is commercially produced in small quantities in several areas of the U.S., Japan, China, and elsewhere throughout the world. Technology has not yet been developed for economically recovering natural gas from geopressured and gas hydrate reservoirs, and these types of gas reservoirs are generally regarded as potential gas kick or blowout hazards if encountered during well drilling operations.

1.1.4. Coalbed Gas Reservoirs

In coalbed reservoirs the natural gas is predominantly stored (~98%) as a molecularly adsorbed phase within micropores. A small amount of natural gas (~2%) is stored by a combination of compression within natural fractures and absorption in formation water. Very little natural gas can be stored by compression in coalbed reservoirs because the fracture porosity generally ranges from less than 1% to 5% and is typically more than 90% water saturated at initial reservoir conditions. Coalbed gas reservoirs result from a unique set of geologic processes wherein the coal performs the dual roles of organic source and reservoir for hydrocarbon gases formed as co-genetic products of the natural coalification process. The gas storage capacity of a coalbed reservoir varies as a function of the reservoir temperature and pressure, the coal compositional properties, the micropore structure and its surface properties, and the molecular properties of the adsorbed gas constituents. However, the actual in-situ adsorbed phase gas content is also a complex function of geologic factors which affected the retention of adsorbed phase gas within the reservoir. Thus, an accurate in-situ gas content value cannot be calculated solely from knowledge of physical coal properties but instead must be directly determined through measurements performed on freshly-cut reservoir coal samples. The primary characteristic of coalbed reservoirs which makes them commercially attractive as sources of natural gas is their ability to store extraordinarily high gas-in-place volumes at relatively shallow depths. The high gas storage capacity is due to the adsorbed phase natural gas having a liquid-like density. For example, the following figure illustrates a comparison of the gas-in-place per unit reservoir volume for a typical coalbed gas reservoir in the San Juan Basin, Fruitland Formation compared to that of a conventional sandstone reservoir of 25% porosity and 70% gas saturation.

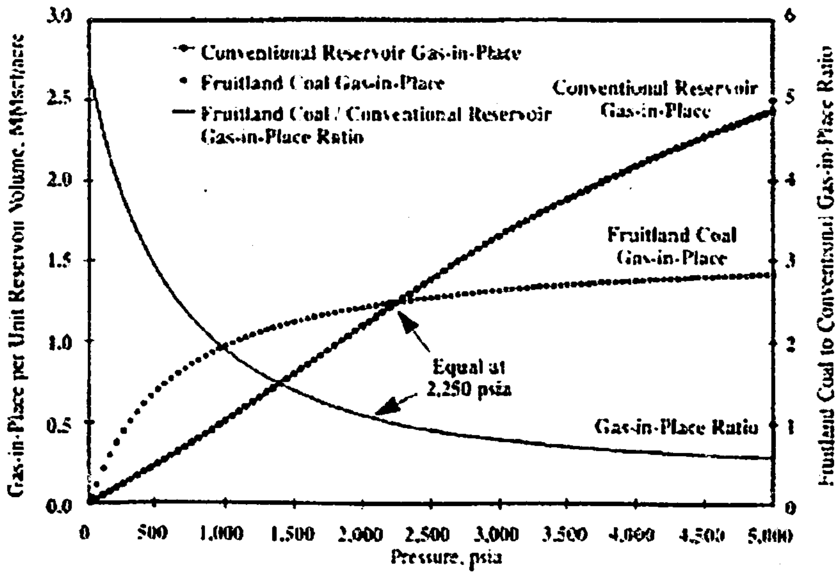


Figure 1.1: Gas in place in Conventional and Unconventional Reservoirs

A greater volume of gas is stored in the coal at pressures less than 2,250 psia. This pressure equates to a depth of roughly 5,000 feet.

1.1.5. Gas-Bearing Shale Reservoirs

In gas-bearing shale reservoirs the gas molecules are stored by a combination of compression within matrix and fracture porosity, absorption by bitumen, and adsorption by organic carbon and clay minerals. The gas storage capacity of shale reservoirs varies as a function of the reservoir temperature and pressure, porosity, total organic carbon content, clay mineral content, and the molecular properties of adsorbed gas constituents. Adsorption generally accounts for over 50% of the total stored gas volume in gas-bearing shale reservoirs. In 1994, gas-bearing shale reservoirs provided nearly 1.5% (259 Bscf) of the total natural gas production in the United States. Currently, the most active plays for gas-bearing shales in the United States are the Antrium shale in the Michigan Basin, the Devonian shales in the Appalachian Basin, the Barnett shale in the Fort Worth Basin; the Niobrara shale in the Denver Basin, and the New Albany shale in the Illinois Basin. A recently published assessment for the Upper Cretaceous Lewis Formation shale in the San Juan Basin of Colorado and New Mexico indicates that this shale formation contains in-place natural gas resources estimated to total 96 Tscf.

1.2. COAL BED METHANE POTENTIALS

Systematic efforts for exploration were made in San Juan basin, USA in 1950. In USA, till date 2.5bcfd of CBM has been produced from 9000 wells which account for 5%. total gas consumption. Among other countries, China is emerging as a major player and Australia is on the threshold of commercial production. India has nearly 260 billion tones of coal resources spread over 15 basins.

US Scenario: 14 basins have been explored. 3 basins; Black Worrier, San Juan and Central Applachian are commercially productive. 95% CBM production is from these three basins.

Table 1.1: CBM Resources in various countries

Country	Coal Resources (10^9 tons)	CBM Resources TCF
Former USSR	4405	600-400
China	1566	1115
USA	1570	420
Australia	785	380
Canada	63	360
India	200	30-53
Indonesia	17	213
South Africa	129	115
UK	190	100
Poland	184	100
Germany	285	100
Zimbabwe	8	1.75

Australian Scenario: CBM exploration started in 1976 in Queensland. Presentally there are 11ATP's (concession areas) in Bowen, Surat/ Bowen and Eromango/ Galilee basins. The total area under exploration is 80,400 sq. km. Exploration and production is also being carried out at a number of coal mines in Bowen basin.

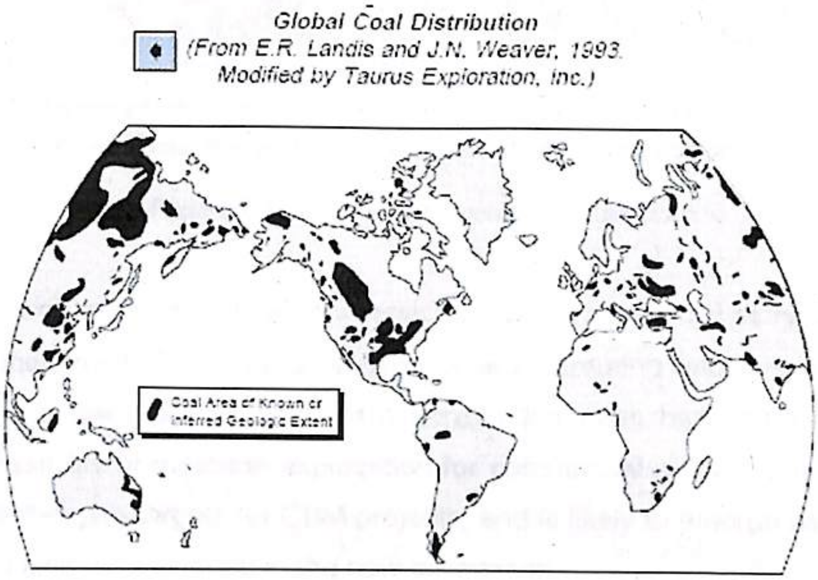


Figure 1.2: Global Distribution of coalbed Methane

Indian Scenario: Natural gas accounts for 7% of the total domestic consumption. Production of Natural gas per year stands at 27 BCM. In order to bridge the ever-increasing energy gap it is necessary to explore and exploit unconventional sources of energy. Methane from coal seams (CBM) is one such potential supplementary energy source. India has the 8th largest coal reserve base in the world. The black gold has been the prime source of commercial energy (68%) in this country. With the projected energy requirements multiplying manifolds in the next decade, it is imperative to exploit this valuable energy resource to tide over the energy imbalance of the country at least partially. Coal bed methane has the potential to supplement at least 5-10% of the total natural gas production of the country in the near future as shown in figure below.

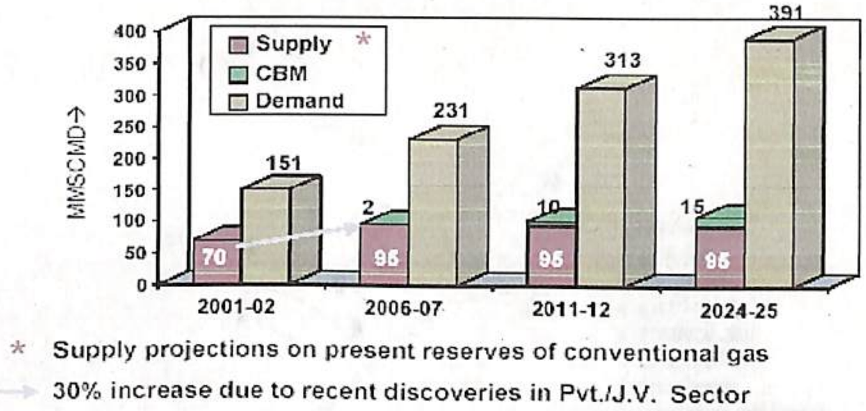


Figure 1.3: *Gas Demand and Supply in India*

Tapping of coal bed methane, which till yesterday had a commercial story limited to USA, is now a global phenomenon and India is aggressively venturing into this new technological horizon. In India a few national and international companies has shown keen interest in exploring the feasibility of methane exploitation for commercial gains. Virgin coal seams are therefore the challenging targets for CBM projects, and is likely to emerge as a new epicenter for full scale gas field development in the new millennium.

There is a vast potential for CBM in India. Coal contributes to 58% of the energy requirements. 98% of coal is spread over Gondwana basins.

India's CBM exploration started in Parbatpur block in Jharia basin in 90's by ONGC. The Gondwana coals are mostly confined to Peninsular India along the prominent river valleys of eastern and central India. Gondwana coals occur mostly in Barakar (Lower Permian) and Ranigang (Upper Permian). Gondwana coals are generally bituminous to sub bituminous. Gondwana coals have high ash (13-14%) and Moisture (<1-11%) contents.

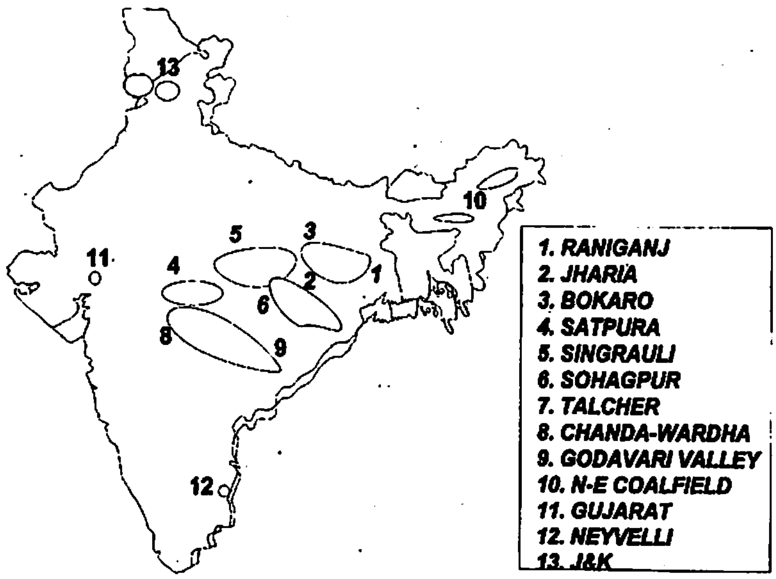


Figure 1.4: Distribution of CBM in India

Maximum gas content of 14.9m^3/ton has been measured at a depth of 790m in Jharia coal field. Potential targets for CBM in Gondwana coals in India are:

1. Jharia
2. East and West Bokaro
3. North and South Kananpur
4. Ranigang coal field
5. Rajmahal area coal field
6. Pench-Kanhan of Satpura basin
7. Cnahda-Wardhan valley.
8. Singrauli and Sahagpur of South Rewa
9. Pranhita-Godavri valley coal field
10. One river coal field in Mahanadi

Coalbed methane is produced commercially in the United States, and it has attracted worldwide attention as a potential source of cost competitive natural gas. Since the beginning of the coalbed methane industry in the mid1970s, operators have modified and applied petroleum industry technology to improve the operation of their fields. However, conventional oil and gas technology does not always work effectively for producing coalbed methane.

Because coal geology is so different from that of typical gas formations, there is a different approach that takes into account:

- *The composition of the rock.* Coal is 90 percent organic, **whereas** conventional gas formations are nearly 100 percent inorganic.
- *The different mechanical properties of coal.* Coal is brittle and weak, and it tends to collapse in the wellbore.
- *Coal's naturally occurring fractures, or cleats.* These fractures, called face cleats and butt cleats, are extensive in coals. Most coal reservoirs, however, require hydraulic fracturing to stimulate production.
- *Coal's gas storage mechanism.* Gas is adsorbed or attached onto the internal surfaces of the coal, whereas gas is confined in the pore spaces of conventional rocks.
- *The large volumes of water present in the coal seams.* **Water must** be pumped continuously from coal seams to reduce reservoir pressure and release the gas.
- *The low pressure of coal reservoirs.* Backpressure on the wellhead must be kept low to maximize gas flow. And all produced gas must be compressed for delivery to a sales pipeline.
- *The modest gasflow rates from coal reservoirs.* Capital outlays and operating expenses must be minimized to produce an economical project.

Chapter 02: THE ORIGIN AND FORMATION OF COAL AND CBM

As organic material is buried, compressed, and dewatered, peat is formed. Peat is a dark brown residuum produced by the partial decomposition and disintegration of plants that grow in marshes and swamps. As peat is buried more deeply, heat and pressure progressively drive off water and volatiles. Peat is then transformed into coal as the carbon content of the fossil organic material increases through devolatilization. In this process called coalification, coals increase in rank from lignite, to sub-bituminous, bituminous, and anthracite. Coal rank is important because it directly influences the gas storage capacity of coal. Several factors influence the rank and type of coal formed: the type of organic material, depositional setting, pH, temperature, reducing potential, depth of burial, and time of burial. Coal by definition is not a unique substance, but rather a group of sedimentary rocks comprised primarily of altered vegetal matter. It is a heterogeneous mixture of components. Mineral matter, water and methane are natural components of coal; their relative proportions are important influences on the value of coal. Coal composition has evolved in response to temperature, pressure, and the chemical environment. Though solid in appearance, coal contains gas and oil-like substances, which are formed during coalification. Part of these substances are retained in coal and part of them are expelled. Coal rank and the relative abundance of various components determine most of the physical and chemical properties of coal.

Methane gas is generated during the formation of coal through 'coalification' process of vegetal matter as shown in the following figure. This can broadly be divided into biochemical and physico-chemical stages of coalification incorporating five successive steps:

- Peatification (anaerobic degradation of organic materials in the peat swamp);
- Humification (formation of dark coloured humic substances by anaerobic degradation);
- Bituminization (generation of hydrocarbons with increase in temperature and pressure);
- Debituminization (thermal degradation of matter and generated hydrocarbons); and
- Graphitization (formation of graphite).

Many physical and chemical changes, governed by biological and geological factors, occur during these processes. Whereas darkening in colour and increase in hardness and compactness are the main physical changes, loss in moisture and volatile contents, and increase in carbon content are the main chemical changes. Many acids (humic, fatty, tannin, gallic, etc.) and dry and wet gases (CH_4, CO_2, N_2, N_2O, H_2S, ethane, propane, butane, etc.) are formed during decomposition of the organic matter. All the changes brought about are attributable to the release of –COOH (carboxyl), >C=O (carbonyl), –OH (hydroxyl) and –OCH_3 (methoxyl) functional groups from the organic compounds which cause the decomposition of vegetal source matter.

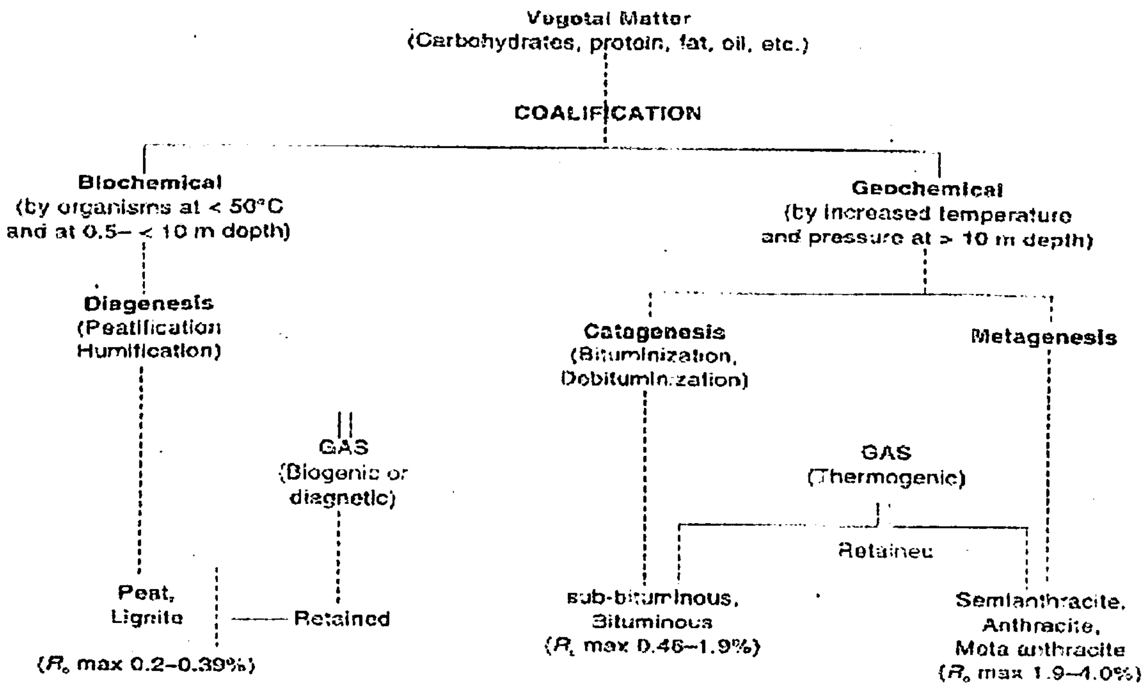


Figure 2.1: CBM Generation

Biochemical stage of coalification, beginning with the accumulation of vegetal matter and terminating at the sub-bituminous stage of coal formation, leads to the formation of a wide range of degradational products – the organo-petrographic entities of coal (termed 'macerals') by the partial oxidation and hydrolytic decomposition of dead vegetal matter accumulated in water-saturated wet lands (basins/grabens) by micro-organisms (fungi, aerobic bacteria, insects, etc.). Further decomposition by anaerobic bacteria extracts oxygen from organic molecules of vegetal matter and results in high concentration of hydrogen. Part of this hydrogen is released as methane or 'marsh' gas and the rest is absorbed by humic colloids.

During subsequent geochemical stage of coalification, rising temperatures and pressures, due to subsidence of the basin/graben, either by growing thickness of overburden or by tectonic activities, generate hydrocarbons (hydrogen-rich constituents). Thermal cracking of the free lipid hydrocarbon fraction and/or cracking of the kerogen fraction of coal generates methane gas. Thus, the generation of coal bed methane during coal formation occurs in two ways:

(i) by metabolic activities of biological agencies (biological process), and

(ii) by thermal cracking of hydrogen-rich substances (thermogenic process).

Methane generated at shallow depths (<10 m) and lower-rank stage (sub-bituminous) by the first process (active up to 50° –80° C) is termed 'biogenic' or 'diagenetic methane'. Methane generated during this process is about 10% of the total methane generated by subsequent steps of coalification (catagenetic: > 80° –150° C, R_0 max > 0.50–2.0% and metagenetic: > 150° –200° C, R_0 max > 2.0–4.0%). Though most of the gas generated during early stages of coalification generally escapes into the atmosphere through the exposed peat or due to low hydrostatic pressure, some amount can accumulate under certain specific geologic conditions like rapid subsidence and burial, and thus may get trapped in shallow reservoirs.

Gas produced at greater depths and higher rank stages of the second process, the thermogenic methane, constitutes bulk of the coal bed methane. The gas generation, by this process, begins at vitrinite reflectance (R_0 max) values of 0.70–0.80%, peaks near the boundary between medium-volatile bituminous and low-volatile bituminous coal stages [R_0 max 1.1–1.4% (maximum at 1.2%), temperature 100° –150° C], and declines further with the rise in temperature and reflectance values[4,5]. Thus, it could reasonably be presumed that the prospect of generation of coal bed methane is more in the regions of high palaeogeothermal gradient as well as in the vicinity of intrusive bodies.

Although, methane is the major gas component of coal gases; water, carbon dioxide, wet gases and liquid hydrocarbons are also released during coalification. Total amount of methane generated during the coal formation (between R_0 max 0.5–2.0%) approximately ranges between 2000 and >5000 Scf/ton . However, part of methane generated is retained in coal beds/seams and is termed 'coal bed methane' (CBM); and the excess above the retention capacity of the coal bed, tends to migrate to the surrounding reservoir rocks (e.g. sandstones).

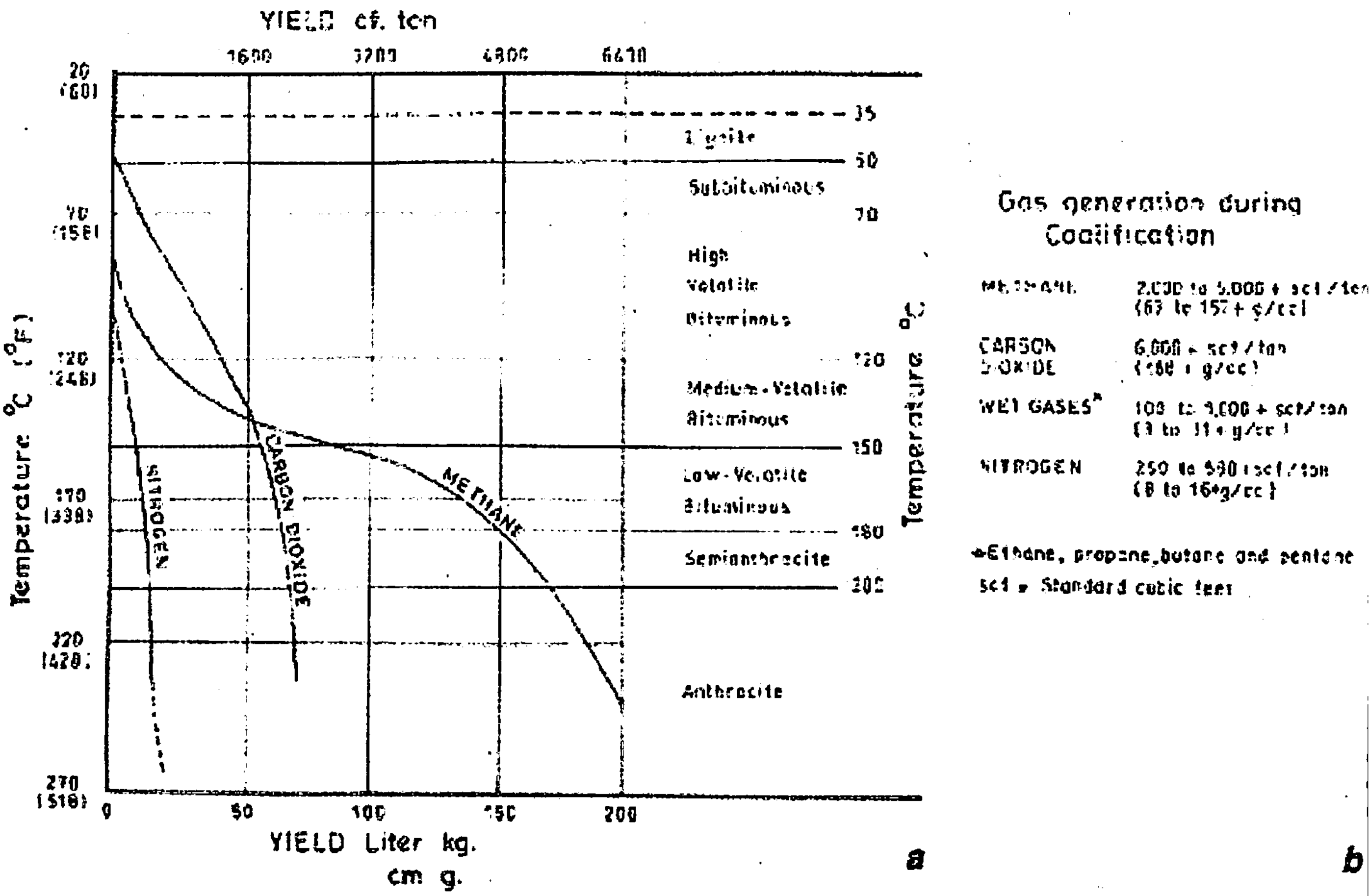


Figure 2.2: a, Relationship between gas generation and coal rank (source Manjrekar); b, Gas volumes generated during coalification up to vitrinite reflectance values of 2.0% (after Scott[6]).

Since methane is generated during coal formation processes, all coals invariably contain methane. However, the gas content of the coal normally increases with (i) rank of the coal, (ii) depth of burial of the coal seams, provided the roof and overburden are impervious to methane and (iii) the thickness of the coal seams.

Chapter 03: COAL RESERVOIR CHARACTERISTICS

Since the beginning of the coalbed methane industry, operators have relied greatly on technology from the mining and petroleum industries to evaluate and develop coalbed methane properties. Much of this conventional oil and gas technology applies to coalbed methane operations, but often it must be modified. In some cases, coalbed methane operations require entirely different techniques. The unique characteristics of coal reservoirs often are responsible for the need to use a different engineering approach. The most important of the unique characteristic of coal is:

3.1. Coal is a source rock and a reservoir rock

The depositional environment and burial history of the coal affect the composition of the gas as well as the gas content, diffusivity, permeability, and gas storage capacity of the coal.

1. **The gas storage mechanism of coal.** Most of the gas in coal reservoirs is adsorbed onto the internal structure of the coal, whereas most of the gas in conventional reservoirs is in a free state within the pore structure of the rock. Because large amounts of gas can be stored at low pressures in coal reservoirs, the reservoir pressure must be drawn down to a very low level to achieve high gas recovery.

2. **The fracture system of coal reservoirs.** Coals contain small (typically, several per inch), regularly-spaced, naturally occurring fractures called face cleats and butt cleats. Coal reservoirs also contain larger-scale natural fractures.

3. **Coal reservoirs often require pumping water before gas is produced.** Typically, water must be produced continuously from coal seams to reduce reservoir pressure and release the gas. The cost to treat and dispose of produced water can be a critical factor in the economics of a coalbed methane project.

4. **The unique mechanical properties of coal.** Coal is relatively compressible compared to the rock in many conventional reservoirs. Thus, the permeability of coal

is more stress dependent than most reservoir rocks. The friable, cleated nature of coal affects the success of hydraulic fracturing treatments, and in certain locations allows for cavitation techniques to dramatically increase production. Because of these and other coal reservoir characteristics, successfully developing a coalbed methane property requires careful evaluation of the geologic and reservoir properties.

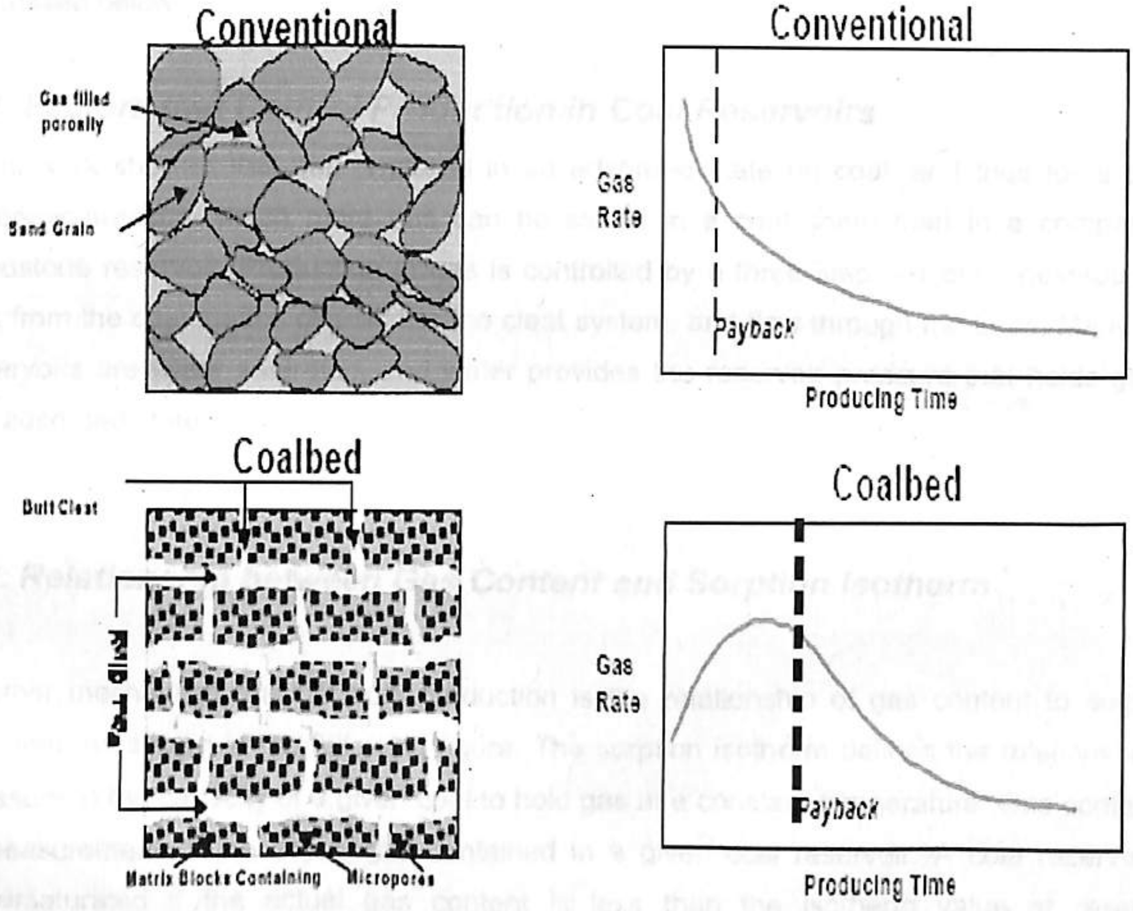


Figure 3.1: Comparison of Conventional and CMB Reservoirs

Chapter 04: UNDERSTANDING THE FUNDAMENTALS OF COALBED METHANE PRODUCTION

To successfully produce coalbed methane wells, it is essential to:

1) identify factors that control production in coal reservoirs,

2) understand the relationship between gas content and sorption isotherm for specific developments, and

3) maintain low backpressure on wells to increase recovery. Each of these points is discussed below.

4.1. Factors that Control Production in Coal Reservoirs.

Early work showed that gas is stored in an adsorbed state on coal, and thus for a given reservoir pressure much more gas can be stored in a coal seam than in a comparable sandstone reservoir. Production of gas is controlled by a three step process—desorption of gas from the coal matrix, diffusion to the cleat system, and flow through fractures. Many coal reservoirs are water saturated, and water provides the reservoir pressure that holds gas in the adsorbed state.

4.2. Relationship between Gas Content and Sorption Isotherm

Another mechanism that controls production is the relationship of gas content to sorption isotherm, as shown in the following figure. The sorption isotherm defines the relationship of pressure to the capacity of a given coal to hold gas at a constant temperature. Gas content is a measurement of the actual gas contained in a given coal reservoir. A coal reservoir is undersaturated if the actual gas content is less than the isotherm value at reservoir temperature and pressure.

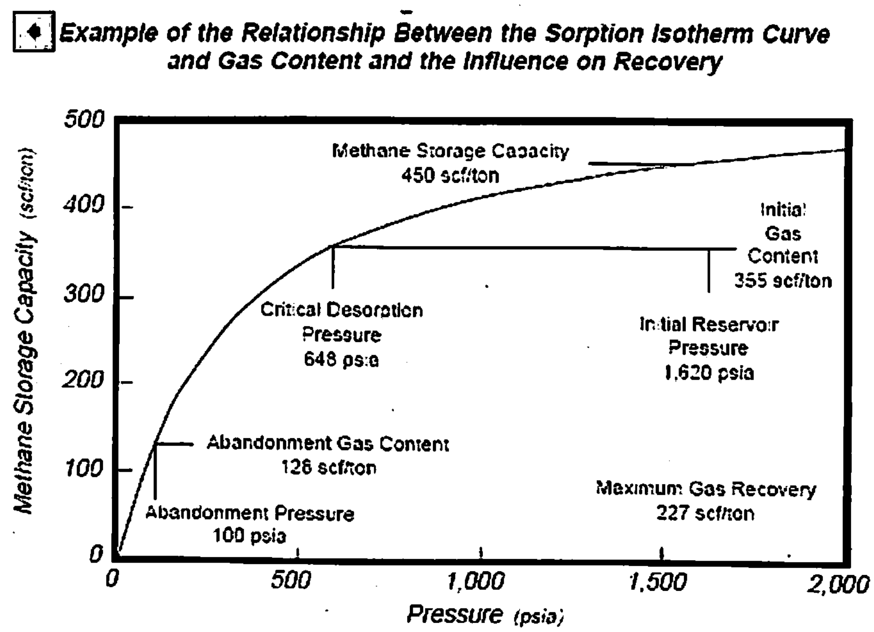


Figure 4.1: Relationship between the Sorption Isotherm curve and Gas Content and the influence on recovery

Accurate measurements of both gas content and the isotherm are required to estimate the production profile of the well.

4.3. Maintaining Low Backpressure on Wells

The ultimate recovery of gas depends on gas content and reservoir pressure. Gas production will not initiate until reservoir pressure falls below the point where the gas content of the coal is in equilibrium with the isotherm. Because most coal reservoirs are aquifers, production of water from the wellbore is the primary mechanism of pressure reduction. If the gas content of the reservoir is below the isotherm, as shown in the figure above, then the reservoir will produce only water initially. After this single phase flow period, bubble flow initiates when reservoir pressure reaches the saturation point on the isotherm. Eventually, two phase flow of gas and water occurs as pressure is further reduced in the reservoir. Because of the relationship between gas desorption and reservoir pressure, it is important to produce coalbed methane wells at the lowest practical pressure.

Chapter 05: PHYSICAL AND CHEMICAL PROPERTIES OF COAL

Physical and chemical properties can vary significantly from seam to seam and over a short distance within a seam. Coal is usually classified by three fundamental characteristics:

Grade. Represents the relative percentage of organic to mineral components.

Type. Represents the various organic constituents.

Rank. Represents the level of maturation reached, ranging from peat through anthracite.

These characteristics are used in classifying coal, as shown in the following figure:

Coal Classification by Grade, Type, and Rank
(Adapted from Alpern et al., 1989)

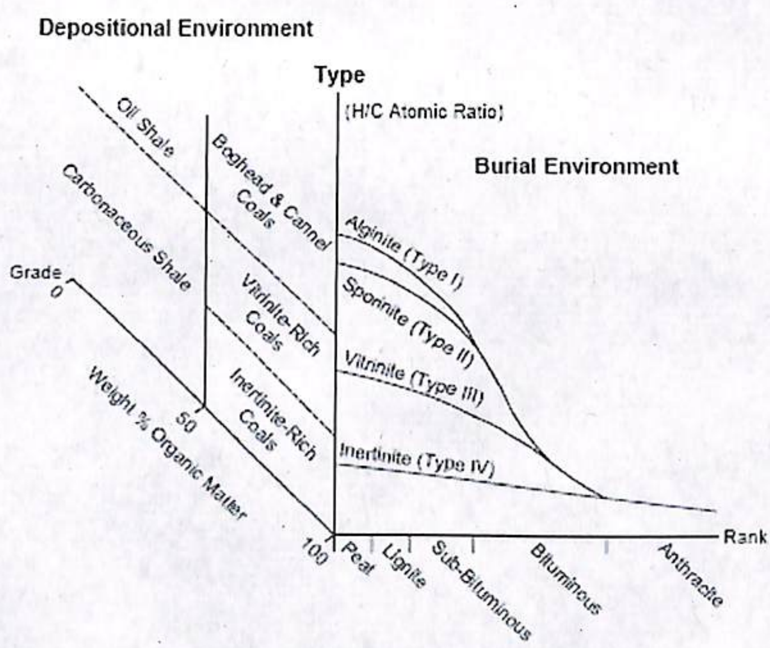


Figure 5.1: Coal classification by grade, type and rank

The three-axis diagram is a petrographic classification of coal composition in which grade, type, and rank are depicted on three orthogonal axes. The composition of coal often is described by proximate analysis and ultimate analysis. A proximate analysis provides the percentage of fixed carbon (FC), volatile matter (VM), moisture (H_2O), and ash content of the coal, as shown in the following figure:

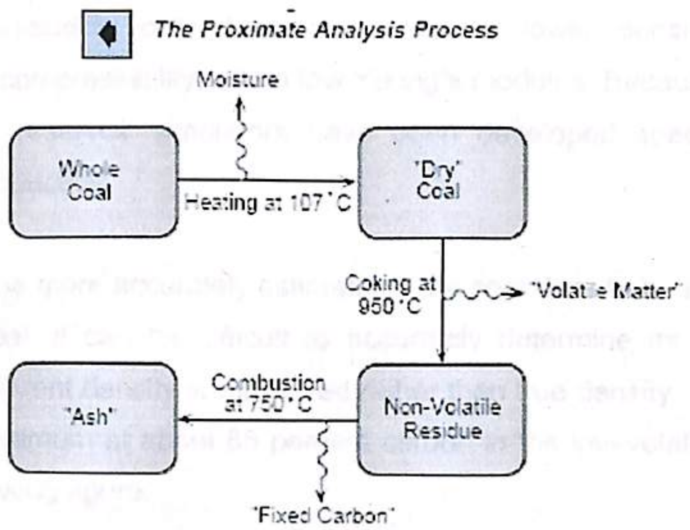


Figure 5.2: Diagrammatic representation of proximate analysis

An ultimate analysis provides the chemical makeup of the coal as percentages of carbon, oxygen, hydrogen, nitrogen, sulfur, and ash. The relative amount of these components can be reported in several ways; the most common include:

- "As received" basis includes FC, VM, H_2O, and ash based on moisture in the coal as received for analysis.
- "Air dried" basis is the same as "as received" except the moisture content is equilibrated to the lab atmosphere.
- "Dry" basis includes only FC, VM, and ash, normalized to 100 percent.
- "Ash-free" basis includes only FC, VM, and H_2O normalized to 100 percent.
- "Dry, ash-free" basis includes only FC and VM, the organic components, normalized to 100 percent.

Physical properties that can be useful in evaluating coal for coalbed methane production are: density, porosity, strength, permeability, compressibility, and a rank parameter (reflectance (*R*), fixed carbon, or heating value). Several physical and mechanical properties of coal are significantly different from most reservoir rock. Some of these differences include a low effective porosity (including only the macropores), a lower density, stress-dependent permeability, a high compressibility, and a low Young's modulus. Because of these and other differences in coal, reservoir simulators have been developed specifically for modeling coalbed methane production.

Coal resources can be more accurately estimated if the coal density is known. Because of the porous nature of coal, it can be difficult to accurately determine its volume and thus its density. Usually, apparent density is measured rather than true density. The apparent density of coal reaches a minimum at about 85 percent carbon in the low-volatile bituminous range, as shown in the following figure:

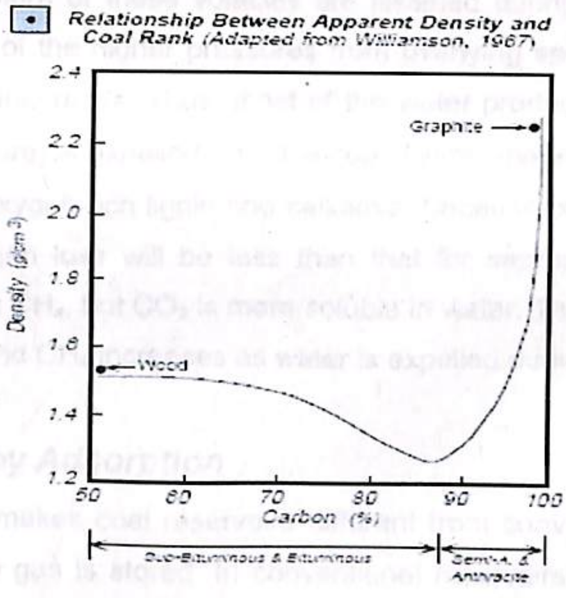


Figure 5.3: Relationship between Apparent Density and coal rank

Chapter 06: METHANE RETENTION IN COAL BEDS

6.1. Gas Generation and Composition

The term "coalbed methane" is not completely accurate because coalbed gas, though composed primarily of methane, includes other gases. When peat is formed, methane and other gases are produced, first by anaerobic fermentation, bacterial, and fungal alteration, and later in the process of coalification by geomechanical alteration through heat and pressure. The gaseous hydrocarbon generated in greatest quantity is methane. Very small amounts of ethane, propane, and butane are also created during peat formation. Because of the low pressure in the swamp environment, nearly all of these gases escape during peat formation. The processes of peat formation and coalification increase carbon in the coal because of the loss of hydrogen and oxygen in the expelled moisture and volatiles. Because much of the volatiles that are produced escape, their volumes are uncertain. Volatiles produced include water (H_2O), carbon dioxide (CO_2), methane (CH_4), nitrogen (N_2), and heavier hydrocarbons. More of these volatiles are retained during coalification than during peat formation because of the higher pressures from overlying sediments. Moisture content decreases as coal rank increases. Thus, most of the water produced during coalification (in addition to original moisture) is expelled from the coal. Humic material, which makes up peat, is composed largely of oxygen-rich lignin and cellulose. Because of the chemistry of a humic coal material, its hydrogen loss will be less than that for sapropelic material. Coal more readily adsorbs CO_2 than CH_4, but CO_2 is more soluble in water. Thus, the retained volume of CO_2 tends to decrease and CH_4 increases as water is expelled during coalification.

6.2. Gas Retention by Adsorption

One characteristic that makes coal reservoirs different from conventional gas reservoirs is the manner in which the gas is stored. In conventional reservoirs, the gas exists in a free state in the pores of the reservoir rock, and thus its behavior can be described by the real gas law. In contrast, nearly all of the gas in coal exists in a condensed, near liquid-like state because of physical sorption. Gases also are present in coalbeds as free gas within the pores or fractures, and/or dissolved in solution (ground water) within the coalbed. Porosity exists in coal as fracture porosity and matrix porosity. Matrix porosity largely determines the ability of coal to retain methane. Most hydrocarbon gases in coal seams are retained by physical adsorption to the coal molecular structure. Proportionately more of the heavier hydrocarbons are retained because they are less mobile than methane. Physical adsorption is caused by weak attractive forces (Van der Waals forces) that exist between pairs of molecules or atoms. Adsorption of methane to coal is caused by such weak physical forces. Adsorption increases non-linearly with pressure and is reversible by increasing the temperature or decreasing the pressure. The sorption capacity of coal can be determined by adsorption testing. Isotherm tests are conducted at a specified moisture content or at equilibrium moisture and at the formation temperature or an assumed temperature. If the reservoir temperature and pressure are known, an isotherm can be used to estimate the maximum amount of methane that might be adsorbed in the coal, the pressure at which desorption will start (if gas content is known), and the amount of methane remaining in the coal at an assumed abandonment pressure.

6.3. Methane Content of Coal

The methane content of coal can be estimated or measured using a variety of procedures. Some methods are sometimes used to estimate gas content if there is no active drilling on a prospect. These methods include estimation from depth and rank relationships, as shown in the following figure:

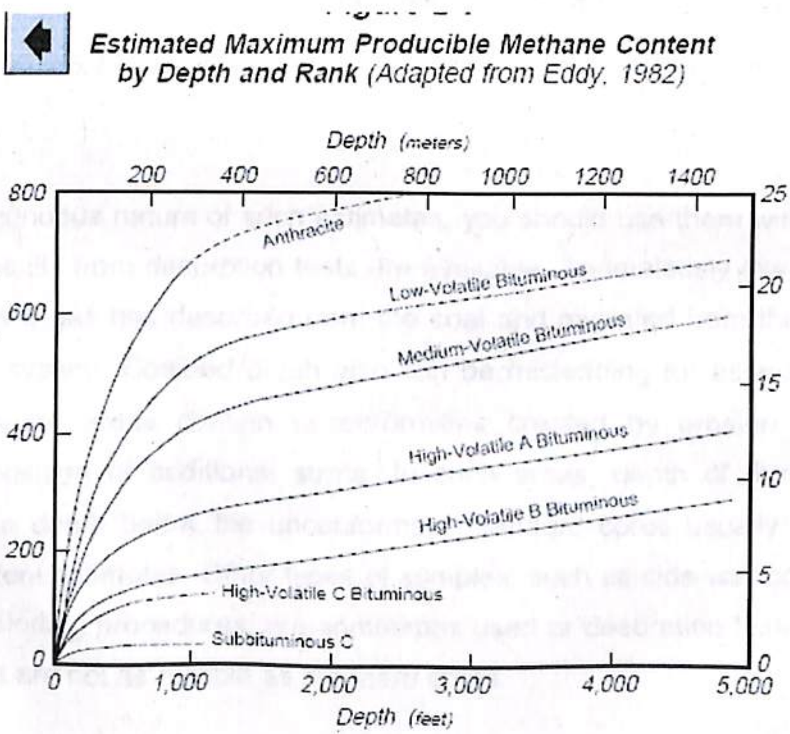


Figure 6.1: Maximum producible methane content by depth and rank

and estimation based on methane emission from coal mines in the area, as shown in the following figure:

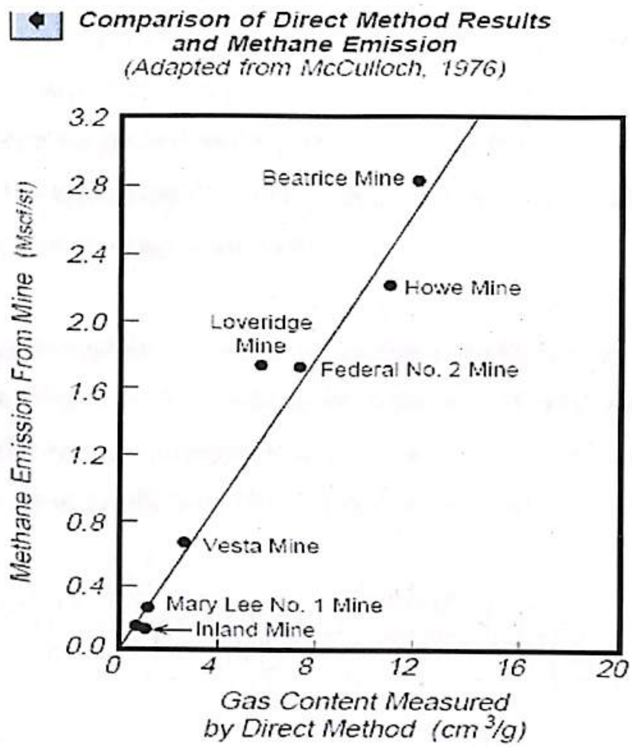


Figure 6.2: Comparison of direct method results and methane emission

Because of the tenuous nature of such estimates, you should use them with extreme caution and only until results from desorption tests are available. Anomalously low gas contents can occur near faults if gas has desorbed from the coal and migrated from the strata through a fault or fracture system. Coalbed depth also can be misleading for estimating gas content. For example, some areas contain unconformities created by erosion of the coal and subsequent deposition of additional strata. In such areas, depth of the coals should be measured as the depth below the unconformity. Standard cores usually provide the most reliable gas content estimates. Other types of samples, such as side-wall cores, drill cuttings, and chips from slotting procedures, are sometimes used or desorption tests. However, these types of samples are not as reliable as standard cores.

6.4. Evaluating Gas Content

Gas is retained in coal mostly by adsorption. Sufficient hydrostatic pressure must be present through geologic history for gas to be retained. If pressure is reduced sufficiently by erosion, uplift, or other means, gas can desorb from the coal leaving little or no gas. Adequate desorption testing should be performed to verify not only the amount, but also the quality of the gas in the coal. The presence of other gases, primarily CO_2, should be determined by analyzing gas samples during desorption tests

Flow of coalbed methane involves a three-step process, as methane molecules move along a pressure gradient. The processes involved in the transport of coal bed methane gas from the coal surface to the well-bore are desorption from internal coal surfaces, diffusion through the matrix and micro-pores and finally fluid (Darcy) flow in the natural fracture network (cleats) of coal.

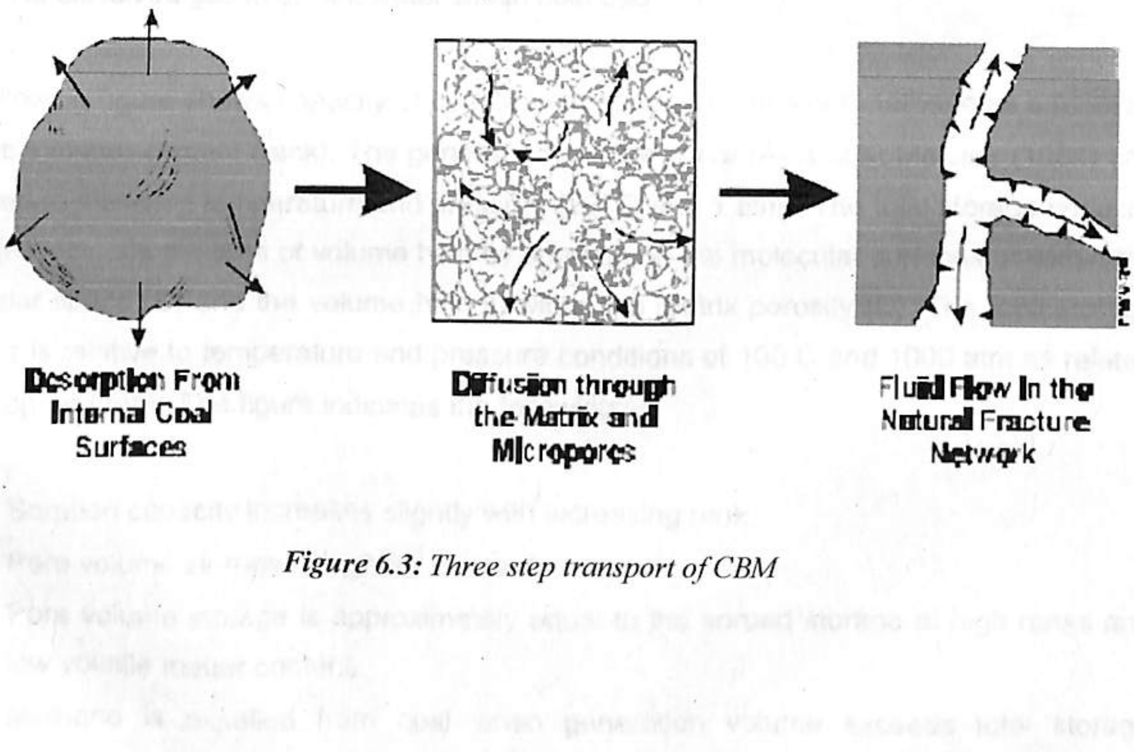


Figure 6.3: Three step transport of CBM

6.5. Formulae Developed

Meissner (1984) plotted the log of volatile matter in coal versus the volume of methane generated.

Volume of methane generated (cc/gm) = -325.6 log(%VM(daf)/37.8)

It is assumed the methane is at 20° C and 1 atm pressure and the percentage of volatile matter was measured on dry ash free basis.

The adsorptive capacity of a coal is a function of pressure (burial depth), coal rank, ash, moisture content and marceral composition. Methane is retained in coal beds in the following four ways:

1. As sorbed molecule in the interfacial surfaces and within the molecule structure of coal.
2. As gas held in matrix porosity
3. As free gas within the fracture network
4. As dissolved gas in groundwater within coal bed

The following figure shows capacity of coal to both generate and store methane as a function of volatile matter content (rank). The generation volume curve (A) is after Meisser (1984) and is related to standard temperature and pressure (20° C and 1 atm). The total storage capacity curve (B) includes the sum of volume held by sorption on the molecular surfaces or within the molecular space (C) and the volume held in within the matrix porosity (D). The total storage capacity is relative to temperature and pressure conditions of 100 C and 1000 atm as related to appropriate rank. The figure indicates the following:

- Sorption capacity increases slightly with increasing rank.
- Pore volume storage is high for low rank coals.
- Pore volume storage is approximately equal to the sorbed storage at high ranks and low volatile matter content.
- Methane is expelled from coal when generation volume exceeds total storage capacity at 29% of V_M(daf).
- Methane starts generating at 38% V_M(daf)

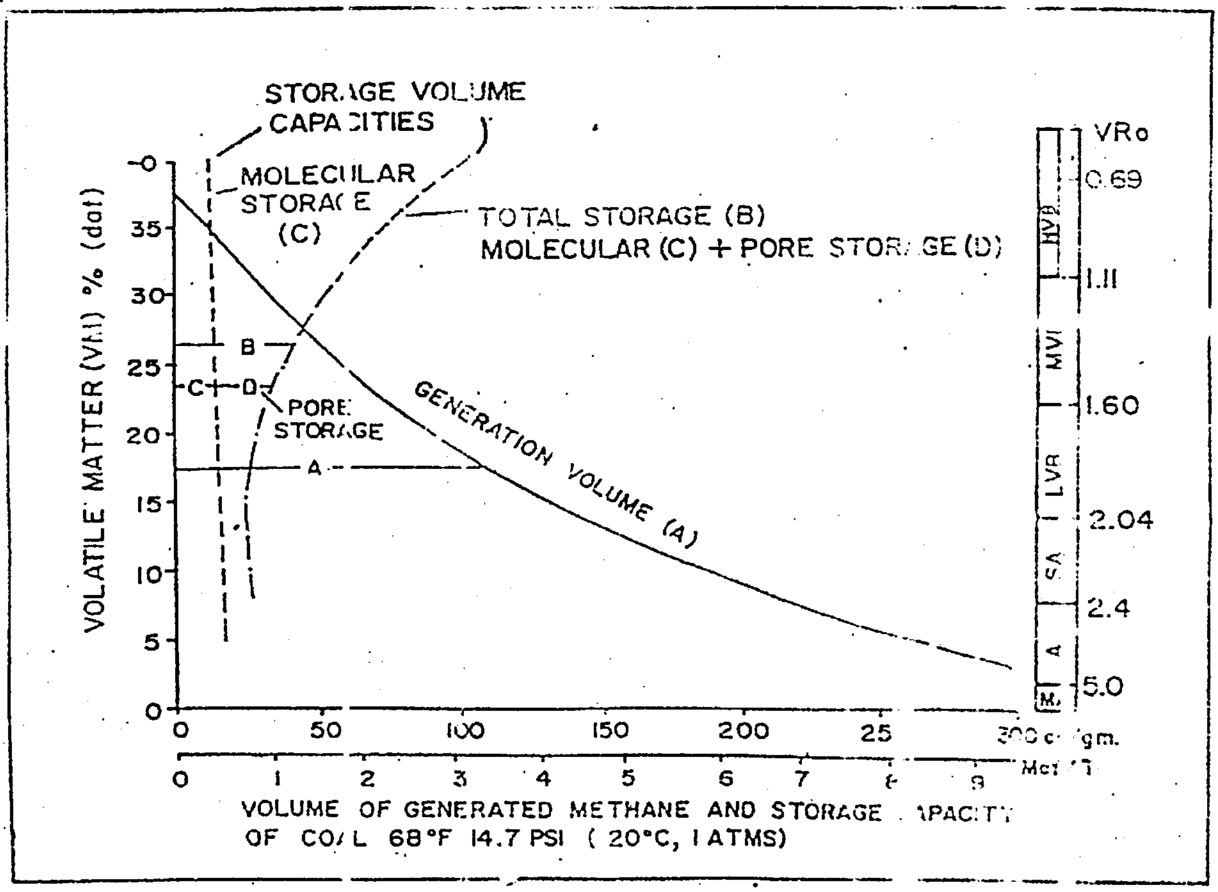


Figure 6.4: Relation between gas generated and gas stored

Kim in (1977) developed a formula based on adsorption isotherms and the chemical composition of coal.

$G(saf)=0.75(1-A-W_C)[k_o(0.095d)n_o0.14(1.18d/100+11)]$

Where:

$K_o=0.8(Xfc/Xvm)+5.6$

$N_o=0.315-0.01(Xfc/Xvm)$

G(saf)- dry ash free storage capacity

A-Ash content, weight fraction

W_C-moistue content, weight fraction

d-depth of sample, m

Xfc-fixed carbon, weight fraction

Xvm-Volatile matter, weight fraction

Chapter 07: GAS IN PLACE

Gas-in-place is the volume of gas stored within a specific bulk reservoir rock volume. A gas-in-place analysis is generally performed for a specific purpose such as gas resource assessment, reservoir production modeling, or geologic hazard evaluation. Gas resource assessments play an important role in the evaluation of new reservoir exploration prospects. Accurate production modeling is critical to achieving optimal development decisions and reliable production potential forecasts for natural gas reservoirs. Gas-in-place analysis is also used in the mining industry to determine if natural gas emissions will be a hazard during tunnel construction or during the mining of coal, oil shale, and potash. Gas-in-place analysis is a very complex process that involves numerous data collection and analysis challenges. The complexity is due, to the fact that most reservoir parameters used for calculating the gas-in-place cannot be measured directly but must instead be indirectly estimated using data obtained by analysis of various rock properties. Four reservoir parameters are needed to calculate the gas-in-place for conventional gas reservoirs: reservoir or well drainage area; reservoir thickness; reservoir rock porosity; and the vapor phase saturation within the porosity. The equivalent four properties for coal gas reservoirs are the area, thickness, reservoir rock density, and in-situ gas content.

Important Geologic Properties that Influence Gas-In-Place and Deliverability of Coalbed Methane Reservoirs

- Coal Resource: Number, Thickness, and Extent of Coal Seams
- Coal Rank, Type, and Quality
- Coal Cleats and Natural Fractures
- Gas Content and Composition
- Sorption and Diffusion Properties of Coal
- Coal Cleats and Natural Fractures
- Geologic Structure
- Stress Setting
- Hydrological Characteristics

The reservoir or well drainage area and the reservoir thickness are usually determined through analysis of geophysical well logs, seismic data, and structure maps. The reservoir rock porosity, vapor phase saturation, density, and gas content are usually determined using data obtained from well logs or laboratory analysis of drill cuttings and core samples. The methodology used for determining the in situ gas content varies considerably depending upon such factors as the analysis type, purpose, and, most important, the reservoir type. The analysis type refers to the basic geologic unit being assessed such as a basin, region, or reservoir. The analysis purpose refers to whether the objective is gas resource appraisal, reservoir production modeling, or geologic hazard evaluation. The reservoir type refers to the physical reservoir environment and gas storage mechanism. There are four principal gas storage mechanisms within reservoir rocks:

- ***Compression*** of gas molecules within rock pores.
- ***Absorption*** of gas molecules by crude oil or brine.
- ***Inclusion*** of gas molecules within solid, crystalline water molecule lattices.
- ***Adsorption*** of gas molecules within micropores.

Another cause of gas-in-place analysis complexity is the fact that reservoir rock compositional properties and gas content are not uniform throughout a given formation but vary both vertically and laterally as a function of numerous geologic variables. Thus, geologic descriptions and physical property data derived from drill cuttings, cores, and well logs are only single sampling point measurements and may not be representative of the average in-situ rock properties throughout a reservoir. The greater the reservoir heterogeneity, the greater the number of samples and sampling sites needed for adequate characterization of the average in situ rock properties.

7.1 Coalbed Gas Recovery

The earliest record of gas recovery from coalbed reservoirs was in China in 900 A.D. where natural gas issuing from coalbeds was transported in bamboo pipes and used as fuel to generate heat for manufacturing salt by brine evaporation. In the United States, the earliest record of gas recovery from coalbed reservoirs was in the early 1900s when a water well drilled into a coal seam in the Powder River Basin was capped and the produced natural gas used as a heating fuel. However, prior to the 1950s the petroleum industry regarded coalbeds only as sources of gas-kicks and blowout hazards during well drill operations. The first deliberate attempts to target coalbed reservoirs in the United States as gas well completion objectives was in the early 1950s in the San Juan Basin. Significant commercial coalbed gas production did not begin in the United States until the early 1980s. Today, technology for economically producing natural gas from coalbed reservoirs has reached a state of demonstrated maturity and these reservoirs are important natural gas exploration targets.

7.2. Coalbed Gas Content Analysis

The growing importance of commercial coalbed gas production has dictated the critical need for accurate gas-in-place data since this parameter is the basis for forecasts of the gas production rates and cumulative gas production volumes from these reservoirs. The in-situ gas content is a crucial parameter in the formula used to calculate the gas-in-place volume, but the accurate determination of in-situ gas content is neither simple nor straightforward. It is not currently possible to use geophysical logging technology to accurately determine the volume of gas stored in-situ by molecular adsorption. This limitation occurs since the presence of adsorbed phase natural gas has little effect upon the physical properties of the bulk reservoir rock. For example, an in-situ adsorbed phase methane content of 400 scf/ton would increase the density of a 100% organic content sample having a density of 1.295 g/cm3 by only 0.010 g/cm3, or 0.8%. Three methods are commonly used for determining in-situ gas content values: pressure coring; direct methods; and indirect methods. Each of these methods has inherent shortcomings which can significantly affect the accuracy and comparability of gas content analysis results.

7.3. Pressure Coring

The pressure coring method involves trapping a cored rock sample down hole within a sealed barrel thereby preventing any loss of gas by desorption while the sample is being retrieved to the surface. The in-situ gas content is then determined by measuring the total volume of gas that desorbs from the sample. The primary advantage of pressure coring is that it is the only method capable of directly measuring the total in-situ gas content of the cored rock sample. However, this method requires specialized equipment that is difficult to successfully operate on a routine basis in the field. Pressure coring is also about five times as expensive as conventional coring methods and its use has generally been restricted to research studies.

7.4. Direct Method Analysis

The direct method analysis procedure was originally developed by the coal mining industry to evaluate the potential severity of natural gas emissions during underground mining operations. This mining industry method involves sealing freshly cut drill cuttings or conventional core samples in an airtight desorption canister and then measuring the volume of gas that desorbs as a function of time at ambient temperature and pressure conditions. The measured desorbed gas volume is not equal to the total in-situ gas content since some gas desorbs and is lost during the sample collection process and some gas is usually retained by the coal at ambient temperature and pressure desorption conditions.

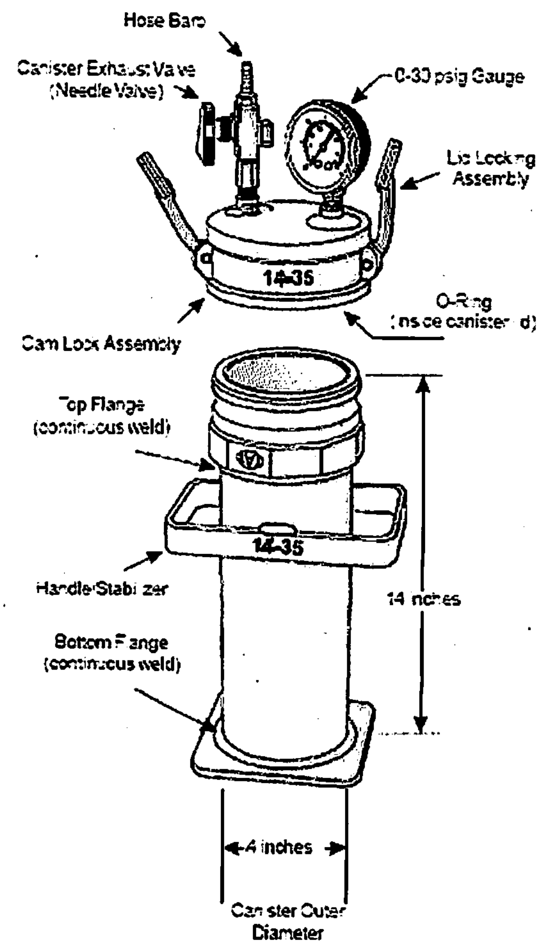


Figure 7.1: Desorption Canister

The lost gas volume is commonly estimated by graphical analysis of the measured gas desorption data. The residual gas volume is determined by measuring the volume of gas released when the coal sample is crushed and heated at the conclusion of the desorption measurements. The total gas volume of the coal is equal to the sum of the estimated lost gas volume, the measured desorbed gas volume, and the measured residual gas volume. The chief limitation of the direct method analysis procedure is that it yields widely different in-situ gas content estimates depending upon the coal sample type and collection methodology, analysis conditions, and data analysis methods. This method-dependent gas content analysis result variation warrants careful consideration when planning or conducting a coalbed reservoir gas-in-place analysis since it indicates that some sample types, analysis conditions, and data analysis methods have inherent shortcomings which bias the gas content analysis result accuracy. For example, the in-situ gas content estimates obtained by analysis of drill cuttings and conventional core gas desorption data commonly differ by 25% or more. Gas content errors of this magnitude cause very large errors in the gas production rates and cumulative recovery estimated using reservoir simulation techniques.

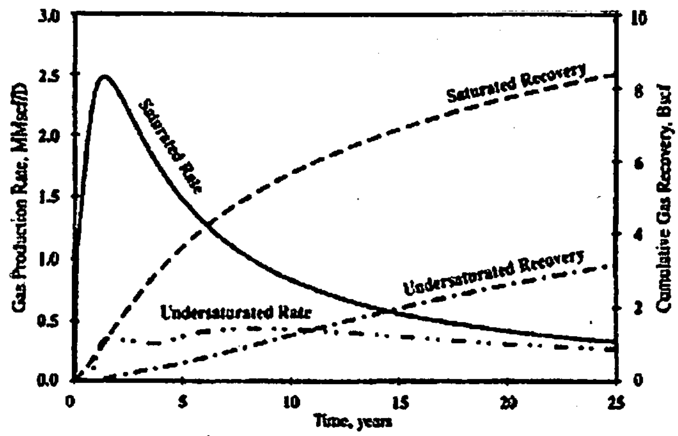


Figure 7.2: Difference in predicted gas production rate and cumulative recovery

The above figure illustrates the differences in predicted gas production rate and cumulative recovery that results from a 30% gas content under-prediction for a typical high productivity San Juan Basin coalbed gas well. The maximum gas production rate was under-predicted by 82%, and the ultimate recovery (gas reserves) was underestimated by 63%. It is not uncommon for the cumulative gas volumes obtained from coalbed reservoir and gas-bearing shale wells with long production histories to be substantially less than or even greatly exceed the initial, producible reserve estimates. As an example, the 10 year cumulative gas production for 23 coalbed gas wells at the Oak Grove field in the Black Warrior Basin of Alabama was 3.2 Bscf, but only 1.55 Bscf of initial gas-in-place was originally calculated to be contained within the coal comprising the reservoirs. The discrepancy was believed to be due to low reservoir volume estimates and low initial gas content estimates. Variances between initial gas-in-place and cumulative gas production volumes of this magnitude warrant careful scrutiny since they indicate a significant potential for reserve growth in existing fields and for expanding the recoverable gas resource base by exploiting coalbed gas and gas-bearing shale resources that are currently viewed as uneconomic.

7.5. Indirect Method Analysis

The indirect method is used when reservoir coal samples are not available and basically involves evaluating the in-situ gas content using empirical correlations which relate known variations in gas content or storage capacity against variations in easily measured independent geologic variables such as coal rank or reservoir depth. Plots of measured in-situ gas content values against vitrinite reflectance or reservoir depth often exhibit apparent linear trends. However, the empirical correlations derived from such data trends generally have very little predictive utility since there is no fundamental relationship between the dependent and independent variables. Thus, the coefficients in the empirical correlations are highly sample set specific which biases their predictive accuracy. Indirect method in-situ gas content values can be very unreliable since coalbed reservoir gas content variation trends can be very erratic throughout a basin.

7.6. Gas Resource Assessments

In-place coalbed gas resource assessments are commonly based upon indirect method gas content values. The following table compares published in-place gas resource estimates for the Fruitland Formation coal in the San Juan Basin of Colorado and New Mexico.

Analysis Type	Analysis Method	Gas-In-Place
Basin	Indirect Method	31 Tscf
Basin	Indirect Method	50 Tscf
COAL Site Reservoir	Indirect Method	26.9 Bscf per Square Mile
COAL Site Reservoir	Direct Method	60.3 Bscf per Square Mile

Table 7.1: *Gas in Place for San Juan basin*

The indirect method in-place gas resource estimates differ by nearly a factor of two. The lower resource estimate (31 Tscf) was obtained using drill cuttings-derived gas content-depth correlations while the higher resource estimate (50 Tscf) was obtained using conventional core-derived gas content-depth correlations. By contrast, the direct method in-situ gas content of San Juan Basin Fruitland Formation coal recovered from a well at the Gas Research Institute's COAL Site research location was 512.4 scf/ton or 110% greater than the 244 scf/ton value predicted by the indirect method gas content-depth correlation. A gas content error of this magnitude causes a very large error in the gas-in-place estimate which for the COAL site reservoir increases from 26.9 to 60.3 Bscf per square mile, a gain of 124%. These comparisons demonstrate that empirical gas content-depth correlations used for conducting in-place gas resource assessments are not adequate for conducting reservoir gas-in-place analysis.

7.7. Additional Gas-In-Place Analysis

Other common sources of error in gas-in-place analysis are underestimation of the gross reservoir thickness and average reservoir rock density. Coal compositional properties and gas content are not uniform throughout the bulk rock comprising a coalbed reservoir but vary both vertically and laterally as a function of such geologic variables as coal rank, depth, ash content, and maceral composition. Analysis data from samples having a broad range of compositional values are needed for reliable determination of the gross reservoir thickness, average reservoir rock density and average in-situ gas content. Coal samples must also be carefully handled at the well site and during transport, storage and testing in order to preserve their original in-situ compositional properties. Air exposure, for example, results in time-dependent alteration of coal's gas emission and compositional properties due to a progressive degradation phenomenon known as weathering. If freshly cut reservoir coal samples are sealed in desorption canisters with a large headspace air volume the subsequent chemical reaction between the oxygen in the air and the coal can cause a significant underestimation error in the desorbed gas volume. Clearly, obtaining accurate gas-in-place values for coalbed reservoirs involves numerous data collection and analysis challenges. The key requirement for obtaining accurate values for average in-situ gas content, gross reservoir thickness, and average reservoir rock density is the use of proper sampling, testing, and data analysis methods.

Chapter 08: CBM PRODUCIBILITY MODEL

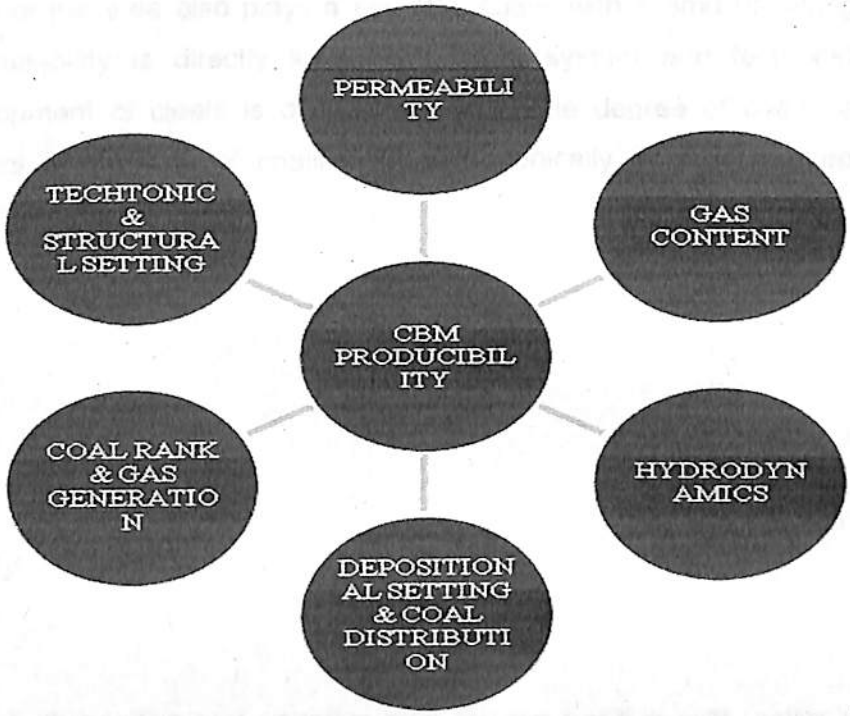


Figure 8.1: CBM Producibility

Synergically, controls of producibility model encompass:

- Thick, laterally continuous coals of high thermal maturity.
- Basinward flow of ground water through the high rank coals down the coal rank gradient towards the no flow boundaries such as hinge lines, facies change etc.
- Generation of secondary biogenic gas.
- Conventional and hydrodynamically trapping of gas along the flow boundries.

8.1. Producibility

Once the presence of high content methane has been established, the success of CBM exploration depends on the permeability of the coal seem. Hydrology, techtonics and structural setting of the area also plays a key role. Clays with > 3md usually give optimum production. Permeability is directly linked with cleat system and techtonically induced fractures. Development of cleats is directly related to the degree of coalification and the intensity of stress at the time of coalification. Techtonically induced fractures, faults etc enhance the permeability of seam.

8.2. Hydrology

Hydrology plays both positive and negative role. On the positive side, active water system lead to the generation of secondary biogenic gas as it transports methanogenic bacteria and helps in enhancing coal seam with methane. On the other hand, active aquifer will make it difficult to dewater the reservoir and reduce the reservoir pressure below the desorption pressure. It may prolong dewatering and make the project uneconomical.

Chapter 09: EXPLORATION AND EXPLOITATION STRATEGY FOR CBM

CBM exploration is a capital intensive and front end loaded technology. Except USA where only 3 out of 20 potential CBM basins could be brought to economical production, CBM projects are yet to be commercially productive in other countries where CBM exploration is being pursued. Reasons for this could be technical, fiscal or legal. The key to success for the CBM venture in these countries would be to collect maximum information to make decisions with minimum financial exposures. This could be achieved through phase development concept. A pre phase study of the basin to be explored for CBM is required, to know whether it holds speculative, commercial and potential value.

PHASE: I-Exploration

During this phase information on coal resources: thermal maturity, cleat and fracture system and hydrology are collected from geoscientific survey at basin level for detailed analysis. With the help of subsurface data generated and gathered full set of maps, geological cross sections, structural contours, isopach, coal rank, gas in place maps are compiled. The above studies lead to qualitative estimation of prioritizing the basins, blocks etc.

PHASE: II-Appraisal-Sizing

The phase includes detailed analysis, integration of geological, geochemical, geophysical and reservoir data. It includes drilling, casing, stimulation and testing of a production well. The test wells are flowed for several months until a stabilized pump off rate is achieved. Geological, geophysical and geochemical information coupled with engineering data during testing help in reservoir simulation. The most critical parameters that is gained from the test well is followed by a closely spaced multi well pilot for faster dewatering, more accurate production potential. The data from the pilot wells not only help in understanding reservoir anisotropy but also in accurate calculation of reserves.

PHASE: III-Development

The data generated in phase I and phase II is utilized in coal seam reservoir modeling by simulators depending upon the economic viability; a development scheme is drawn up. Drilling, completion, stimulation of development wells, installation of artificial lifts and bringing the wells into production, erection of surface facilities etc are carried out in this phase.

PHASE: IV-Production

The production phase commences with the completion of installation of surface facilities and marketing tie ups. During this phase continuous reservoir and production management is required to keep up the production rate.

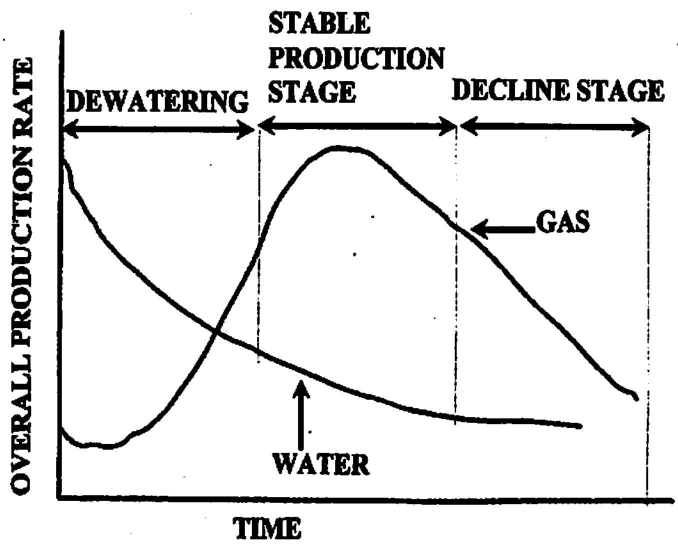


Figure 9.1: Production profile of a CBM well

Chapter 10: ECONOMIC ANALYSIS OF CBM

CBM development and production trends of US indicate a production potential of 10016 m^3/day by the turn of the century. As mentioned elsewhere, many countries have taken keen interest and are pursuing exploration for CBM. Few countries like China and Australia are reported to have established commercial reserves. Other countries like Great Britain, Canada, Spain, India, Poland, Russia, Zimbabwe etc are either in initial exploration phase or have entered into pilot project phase. The resource potential of some of the countries like China and Russia are quite large. It may not be very far when the CBM becomes truly an internal business and the world right now may be witnessing the "Birth of a new energy industry". For this to happen, CBM will have to compete in its economics with conventional natural gas. CBM projects suffer from a case of mistaken identity. They are considered 'low risk', 'low technology', 'large coal reserve : large CBM', 'low cost' and 'all CBM projects are alike. For a CBM venture to be successful, the technical, political and commercial conditions are required. In US, the CBM success was mainly because of large tax concessions, technology development for cost effective production, existing infrastructure and availability of large gas market. The key economic factors that can make a CBM project successful are attractive rate of gas production, competitive cost, and economics of scale.

10.1. Gas Rate

The key economic consideration for CBM is to produce gas at a higher rate to produce very large volumes ultimately. CBM/well/day production in USA ranges from 1000 m^3/day to 150000 m^3/day. The endeavor should be to develop a geological and geophysical capability to locate fairways or sweet spots in a basin and effectively drill, complete and operate production well, the ultimate goal being to produce near the upper end of the range.

10.2. Competitive Cost

Generally the cost of CBM wells is low to moderate being shallow and on land. The low well and operating cost should make the lower gas producing wells economical.

10.3. Reliable Markets

Availability of gas markets may not be a problem these days as most of the countries are switching over to gas based industry.

10.4. Economics of Scale

The final key for a successful CBM project is economics of scale i.e. large volumes. A critical mass of wells is required to provide a base support for the essential geological, engineering and operations associated with a successful CBM project. The threshold values for a remote basin should be 400 wells or 6 million m^3/day production.

10.5. CBM in India

CBM in India is an emerging technology and is viewed as a potential new energy resource. It is in its infant stage right now. With the recent success in Thania coal field area, the thrust for CBM exploration is going to be increased manifold. With proper incentives and efforts the country can tap the vast potential of CBM. However, a word of caution is that this alternate source of gas demands optimization of technical excellence, adoption of management expertise in cost reduction and Government vision. The distance between the consumer and production well determines the gas price as the transportation cost is deducted from the market price to fix the well head price. If the distance is too large it may effect the economics.

Chapter 11: CASE STUDY: OVERVIEW OF THE POTENTIALS AND PROSPECTS OF CBM EXPLORATION AND EXPLOTATION IN COALS OF BARAKAR FORMATION, JHARIA BASIN, INDIA

India, which has the sixth largest coal reserves in the world, is expected to have a reasonable potential for CBM. In 1992 evaluation started with a well test in the Parbatpur block of the Jharia basin. Since then, efforts are being made to exploit this energy source cost effectively. About 99% of the coal reserves of India are in the Gondwana basins, while the remaining are in the tertiary basins. The Gondwana basins have been prioritized for evaluating their CBM plays, with the Jharia and East Bokaro basins on the top. CBM exploration and exploitation activities are still in the initial stages of research and development. Geo-scientific, reservoirs and production characteristics are integrated to evaluate the CBM production of the Jharia basin for the next twenty years. In this study a production decline technique and a material balance and flow equation calculation are discussed on their usefulness.

11.1. Geology and Structure of Jharia Basin

The Jharia basin is a sickle-shaped Gondwana basin with an extend of about 450 sq km. Lower Gondwana sediments are surrounded on all side by Pre- Cambrian metamorphic. The Barakar formation is the main coal bearing stratigraphic unit. Although, more coal seams are also present in the Ranigang formations. Locally igneous intrusions affect the coal quality. The southern and northern basin margins are faulted. Field examination of cleat and fracture system indicates that the cleat systems are open. Other fractures like joints are also open, but in the vicinity of faults these fractures are reduced by secondary fillings. The coals contain buff colored, coarse to medium grained feldspathic sandstones, grits, shales, and carbonaceous shales. The pre- stimulation permeabilities ranges from 0.01 to 3.5 mD. The Barakar coal seams are the main exploration targets.

Table 11.1: Properties of Jharia basin

Basin	Damodar
Formation	Barakar
Vitrinite	57% volume
Inertinite	42.6% volume
Liptinite	0.4% volume
Vitrinite Reflectance	1.08%
Mineral Matter	14.82% dry mass
Pure Coal	85.18% dry mass
Moisture	3.49% mass
ASTM	Medium- High volatile bituminous
Temperature	46 ° C
Depth	375m
Thickness	1.28m

11.2. Gas Storage and Recovery Factor

A sorption isotherm is a primary coal analysis that is measured on coal. It is assumed that they can be fit to the Langmuir relation. The isotherm including the parameters for the coal sample is represented by,

$G_s = V_L(1-f_{ad})P/P+P_L$

For the core sample described above the parameters for the equation are as follows:

V_L= 586.37scf/ton

fad= 0.196

P=525psi

P_L=360psi

Substituting the values in the equation we get, G_S= 279.66scf/ton.

In a CBM reservoir, the volumetric reserve calculation is the product of gas in place (GIP) and the estimated recovery factor at the economic limit. The gas recovery factor (R_f) is the most difficult parameter in the volumetric equation to estimate accurately.

The recovery factor is estimated from the isotherm using:

R_f= (Cgi-Cga)/Cgi.

Here Rf is the recovery factor, Cgi the initial sorbed gas concentration and Cga the abandonment pressure sorbed gas concentration.

The major disadvantage of this method is that the average reservoir pressure at abandonment is usually dependent on the future economic condition in addition to reservoir properties and production history of the reservoir. Thereby, the abandonment pressure (Pa) is defined as the pressure where the gas rate becomes too low, and the production of CBM no longer will be cost effective.

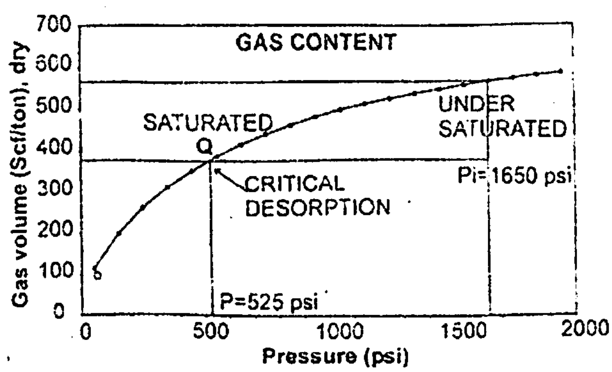


Figure 11.1: Graph between gas volume and pressure

In the example mentioned above, the Langmuir pressure is 360psi. Below this pressure the well will produce. An abandonment pressure of 100psi is assumed for the estimated recovery factor. Hence, the gas content at initial pressure (C*gi*) is 364scf/ton, the gas content at abandonment pressure (C*ga*) is 114scf/ton and based on the above, the recovery factor is estimated as 68.7%.

11.3. The Advanced Material Balance Technique

The mass balance technique neglects the storage of gas in the cleat system. The amount of cleat related gas is insignificant compared to the adsorbed gas in the coal matrix. The technique relates the adsorbed gas content directly to reservoir pressure without consideration for cleat system fluids or cumulative water production from the cleats. Hence the dewatering of the coal in the wet areas will not affect the linear nature of the modified pressure function versus the cumulative gas production data, during the early production life of the well. In practical terms, it does not matter how the pressure declines, the Langmuir isotherm defines the remaining gas adsorbed on the coal as a function of pressure. The initial equation is as follows, where G_p is the current gas produced; OGIP is the original gas in place.

$$G_P = OGIP - CGIP \qquad \text{(eq: 11.2)}$$

Connecting the gas in place (G_P), to the area connected to the wells in acres (A), net coal thickness in feet (h), and coal density (d) in tons/ (acre-foot) gives:

$$GIP = V*A*h*d \qquad \text{(eq: 11.3)}$$

Substituting (eq:3) in (eq:2) gives;

$$G_P = V_i*A*h*d - [P/(P+P_L)]*V_L*A*h*d \qquad \text{(eq: 114)}$$

The expression on the right of the (eq:4) is obtained by substituting Langmuir's equation for current gas content (V). Substituting Langmuir's equation for V_i we obtain the final equation in slope intercept form:

$$[P/(P+P_L)] = -1/(V_L Ahd)*G_P + [P_i/(P+P_L)] \qquad \text{(eq: 11.5)}$$

Equation 5 represents a graphical analysis of pressure behavior that can be used as an independent ultimate recovery prediction tool to complement simulation prediction, where;

$-1/(V_LAhd)$ is the slope and $[P/(P+P_L)]$ is the y- intercept.

11.4. Case Study, production decline curves

One of the wells (X) is located at the expected no flow boundary between the surrounding producing wells. This allows the measured pressure to be indicative of the reservoir pressure, since it is not subjected to near well pressure draw down effects. The pressure data used is an average of the pressure profiles of all the five producing coals seams as shown in the following figure.

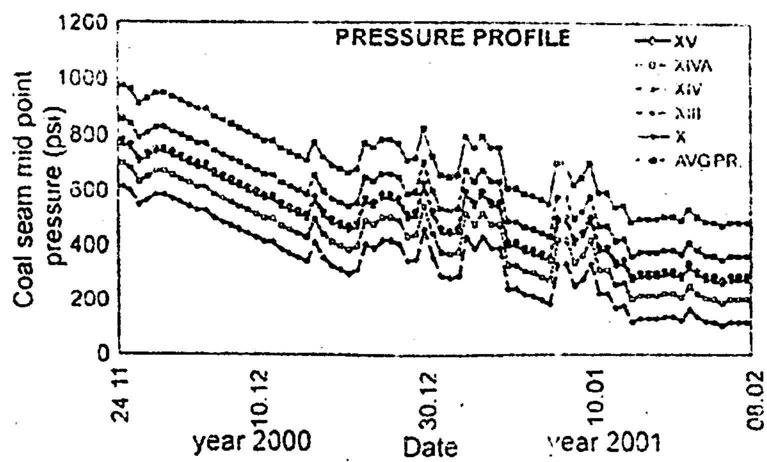


Figure 11.2: showing pressure drop of various seams and average seam pressure drop, during production.

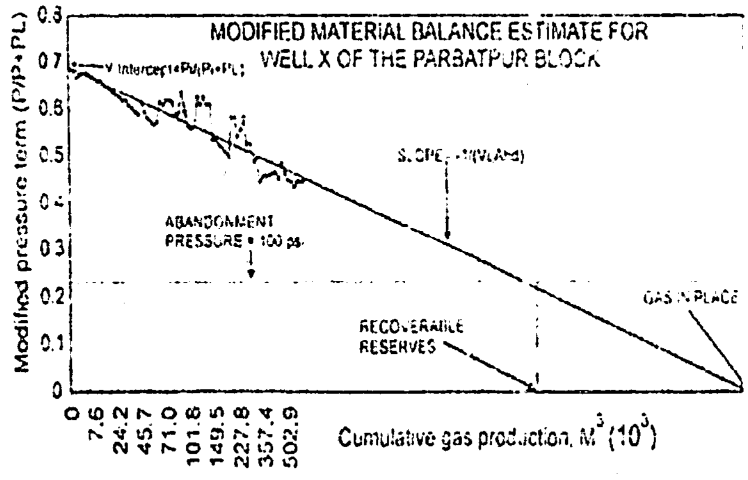


Figure 11.3: estimated gas reserve as a function of pressure and cumulative gas production

The cumulative production data, associated with each pressure, is the sum of five producing coal seams. The following figure illustrates the application of the well X on production data set. The cumulative gas produced is plotted on the X axis and the modified pressure term ($P/P+P_L$) on the Y axis.

The X intercept of the data extrapolation indicates the original gas in place in the drainage area. An average Langmuir pressure (P_L) value of 360psi was used, as derived from eq (1). An expected abandonment pressure of 100 psi is assumed. Extrapolation of pressure and cumulative production data back to Y axis yields a calculation of the initial pressure. Analysis of the slope of the extrapolated line is useful for determining information about reservoir properties like Langmuir volume, drainage area, thickness of producing zone and the density of coal. It provides a qualitative check of the whole reserve.

Collectively a practical method for coal gas reserve estimation, using reservoir pressure has been presented. To increase confidence in an estimated recovery of CBM the data gathered is compared with that from production decline analysis, reservoir simulation and volumetries.

11.5. Role of the Permeability in Techno Economics

Worldwide experience of the CBM production establishes the fact that producibility varies widely within a basin. Variation in the permeability of the producing coal seams is the main reason. It is principal controlling factor for efficiency of dewatering process, upon which the decline in reservoir pressure, and by that desorption and production of CBM, largely depends. A fall in producibility with decreasing permeability has lead in the CBM industry to define one millidarcy as the lowest limit of permeability for economic exploitation. Below this value production is uneconomical, since the dewatering process starts to be inefficient. In contrast with conventional reservoirs, the permeability of a coal seam is the most important criterion, followed be the gas content and the seam thickness. Permeability in coals is highly stress dependent, which expresses itself in reduction with depth. Shallow depths favor faster desorption of the gas during pressure decline.

The Barakar formation in Jharia basin has been subdivided into the Lower, Middle and Uper Barakar. Lower recovery factors for the Lower Barakar sequence is primarily due to the following reasons;

- A lower permeability ranging from 0.1 to 0.01 mD.
- Reasonably high cleat porosity, resulting in an initial high amount of water within the drainage area of the well.
- Low permeabilities related to water phase, which make dewatering, de pressurization and gas desorption a slow process. A high irreducible water saturation of 45-50% also affects the dewatering process.

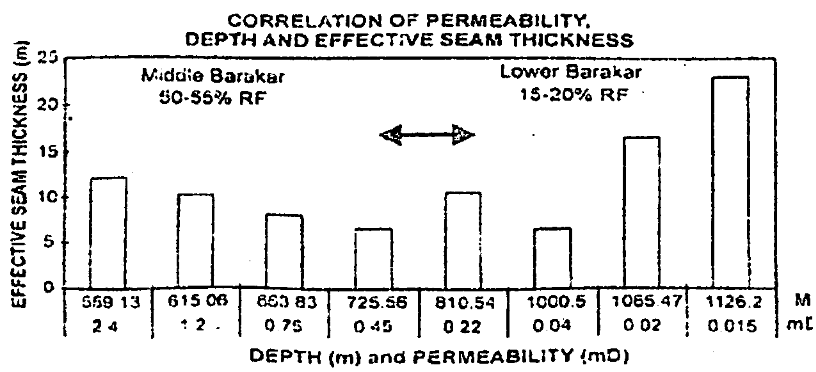


Figure 11.4: Barakar coal seams, net thickness versus permeabilities

In spite of their enormous thickness, lower permeability coal seams tend to yield very low recoveries. Thickness can only add to the reserve in place. They play no role in the improvement of the flow characteristics and therefore no role in improving the efficiency of dewatering. Hence, dewatering is the very basis of CBM production and is likely to affect the techno economics.

11.6. Production Decline Analysis

Production decline trends of producing CBM wells can be analyzed to estimate future production for coal bed wells. Decline curve analysis is widely accepted in conventional oil and gas industry, since it only requires the well's production history. Using a decline curve analysis technique for CBM wells is complicated by the fact that it may take several months to years to show a declining production trend. Well spacing, permeability, producing conditions, and the diffusion characteristics of coal all affect the shape of the production profile. Analysis of pressure transients in simulated cases show that the decline trend is established when the outer flow boundary effects dominate the flow characteristics (pseudo steady state flow). Therefore, declining production trends tend to be best developed in wells tat are part of a producing well pattern, in which each well is interfering with other production wells. The criteria for declining curve techniques are:

- Decreasing gas and water rates
- Consistent slopes in gas rates for at least six months
- The production life is more than 22 months, including a six month declining period
- The wells are showing interference behavior

Usually not all the parameters are met for each well. However, when most of the criteria are met, there is a high degree of confidence in the production forecast based on the decline analysis. The following figures illustrate the use of both the exponential decline technique and the hyperbolic decline technique for estimating the future production of our example well (Well X) with a comingled production.

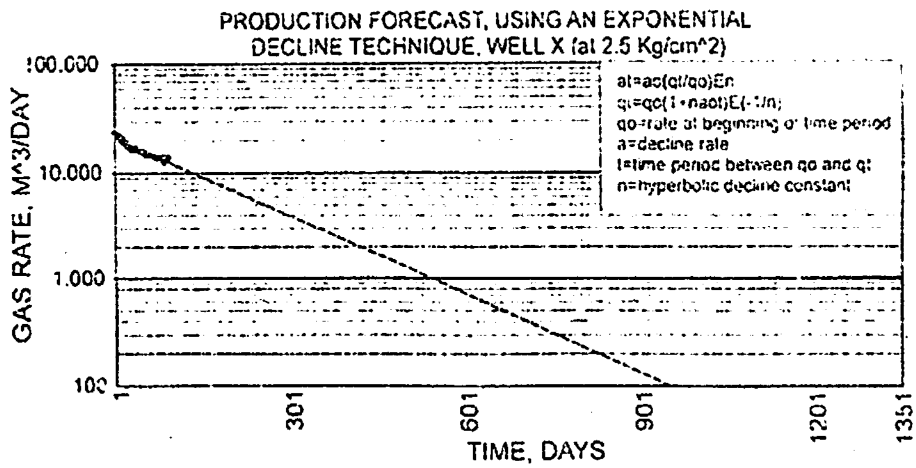


Figure 11.5: Production forecast, using production rate, time and an exponential decline technique

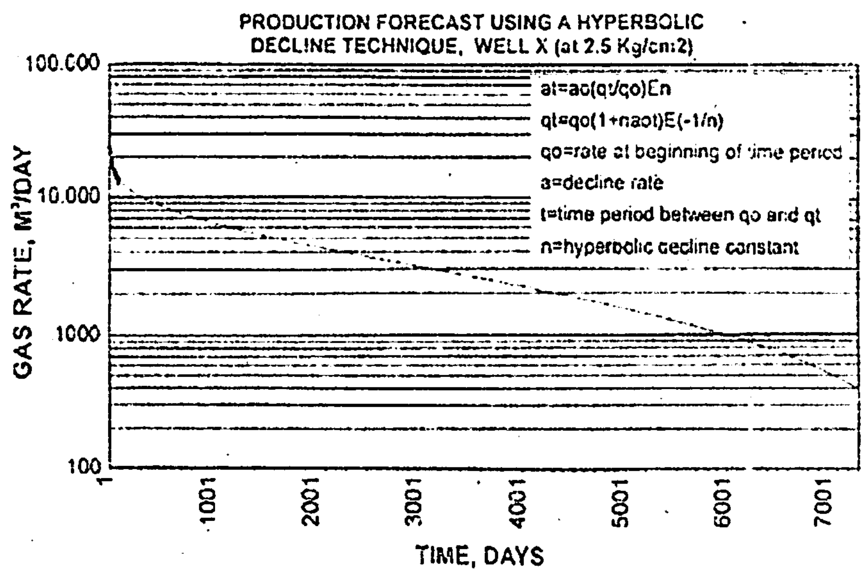


***Figure 11.6:** Production forecast using production rate, time and a hyperbolic decline technique*

Exponential decline curve equations are used most often for analyzing oil and gas wells. This type of decline is a constant percentage decline, which is characterized by straight line on a graph of production against time. Here the log of the production rate is plotted against the production time. The set of exponential decline equations are :

(a) $q_t = q_0 e^{-at}$ (eq 11.6)

where (q_1) is the production rate, using the initial production rate (q_0) and cumulative producing time (t).

(b) $a = \frac{\ln q_0 - \ln q_1}{t}$ (eq 11.07)

the equation calculates the decline rate (a) from a list of measured production data, with :

(c) $t = \frac{-\ln(q_1/q_0)}{a}$ (eq 11.08)

as the time rate (t) equation, and ;

(d) $LR = \frac{q_0 - q_1}{q_0} = 1 - e^{-at}$ (eq 11.09)

as the loss ratio, (LR)

The equations 6 to 9 are used to calculate the cumulative production (Gp) :

(e) $G_p = \frac{q_0 - q_1}{a}$ (eq 11.10)

In this study, the coalbed methane production data partly follow the exponential decline equation. The time zero of the production data partly follow the exponential decline equation. The time zero of the production data has to be reset to the point of where the production data starts with an exponential decline. This adjustment reduces the time span. To estimate the initial production rate, the rate data are extrapolated. To apply these equations, the units for decline rate and production rate must be consistent (i.e., decline rate expressed as "percent per day" and production rate as "Sm3 per day").

Figure shows the semi log graph of daily production rate plotted against time for Coalbed Methane well with a backpressure of 2.5 bar. For this analysis the last six months of production data have been analyzed. A least squares fit of the production data gives a decline rate as shown on individual plots. This line was extrapolated and used to estimate the ultimate recovery at some economic limit.

The same set of production data is also set to fit into the hyperbolic decline equations. A hyperbolic decline is characterized by a constant change of decline rates with respect to time (i.e. the derivative of the exponential decline equation). The set of hyperbolic decline equations are:

(a) $q_1 = q_0(1 + na_0t)^{-1/n}$ (eq 11.11)

This equation is used to calculate production rate (q1) using initial production rate (q0) and cumulative production time (t), as function where n is the hyperbolic decline constant and a0 varying decline rate.

b) $a_1 = a_0(q_1/q_0)^n$ (eq 11.12)

This equation calculates the decline rate (a1) from a fit of measured production data.

c) $t = (q_1/q_0)^{-n} - 1/na_0$ (eq 11.13)

is the time rate (t) equation, and;

d) $LR_1 = 1 - (1 + na_1)^{1/n}$

represents the loss ratio (*LR1*).

Equations 11 to 14 are used to calculate the cumulative production (Gp):

e) $$G_p = \frac{q_0^n}{(1-n)a_0(q_0^{1-n} - q_1^{1-n})}$$ (eq 11.15)

Figure is the semi log graph of daily production rates plotted against time with a hyperbolic fit.

11.7.Analysing the Suitability of the Procedure

Before the comparison of the exponential method with the hyperbolic decline method, it is stated that an exponential decline method is more suited for oil and gas production prediction rather than coalbed methane production forecasting. Going by the typical production profile of a coalbed methane well, this profile differs significantly from the typical decline of a conventional gas well as shown in the following figure.

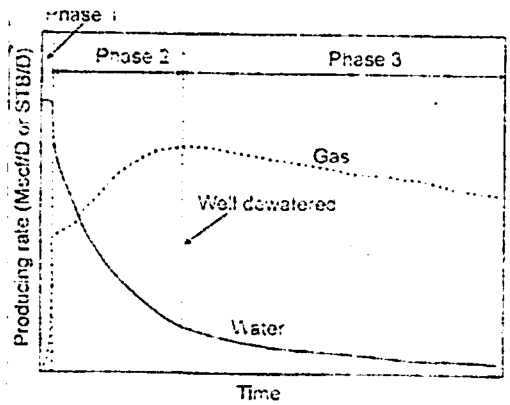


Figure 11.7: Production phases of a well during production

The "Phase 3" of a production profile begins when reservoir flow conditions have stabilized, the well has reached its gas rate, and the gas production is characterized by a more typical decline trend. The well is dewatered at the beginning of Phase 3. During this phase water production is low and/or negligible, and the relative permeabilities for gas and water change very little. The pseudo-steady state flow persists for the rest of Phase 3 and the producing rates of gas and water are controlled by the physical properties of coal, as well as the boundary conditions. Classic pressure transient behavior of a dual porosity reservoir is based on mathematical models, which are developed by Warren and Root (1977). The classic behavior does not occur in coalbed methane reservoirs. In an idealized dual porosity reservoir the pressure derivative profile is divided into an initial well bore storage period followed by an infinite acting period. The unit slope of the profile is 45˝ during the well bore storage period. At the end of the well bore storage period most of the fluid production originates from the reservoir. The infinite acting period in the classic dual porosity reservoir is characterized by three sub-periods, a fracture system dominated sub-period, a system transition sub-period and a matrix system dominated sub-period. During the fracture system dominated sub-period, the production originates from the secondary porosity. As time continues, the fracture system dominated sub-period ends as fluid starts to flow from the matrix system. In between a system dominated sub-period a production fall and a corresponding rise in the pressure derivative is observed. This classic pressure behavior does not occur in coal gas reservoirs that produce both gas and water. The single-phase flow tends to occur during the fracture phase dominated sub-period and the multiphase flow tends to occur during the matrix system dominated sub-period. The change from single to multiphase flow changes the fluid flow rate through the reservoir and the resulting derivative behavior is as shown in the figure below:

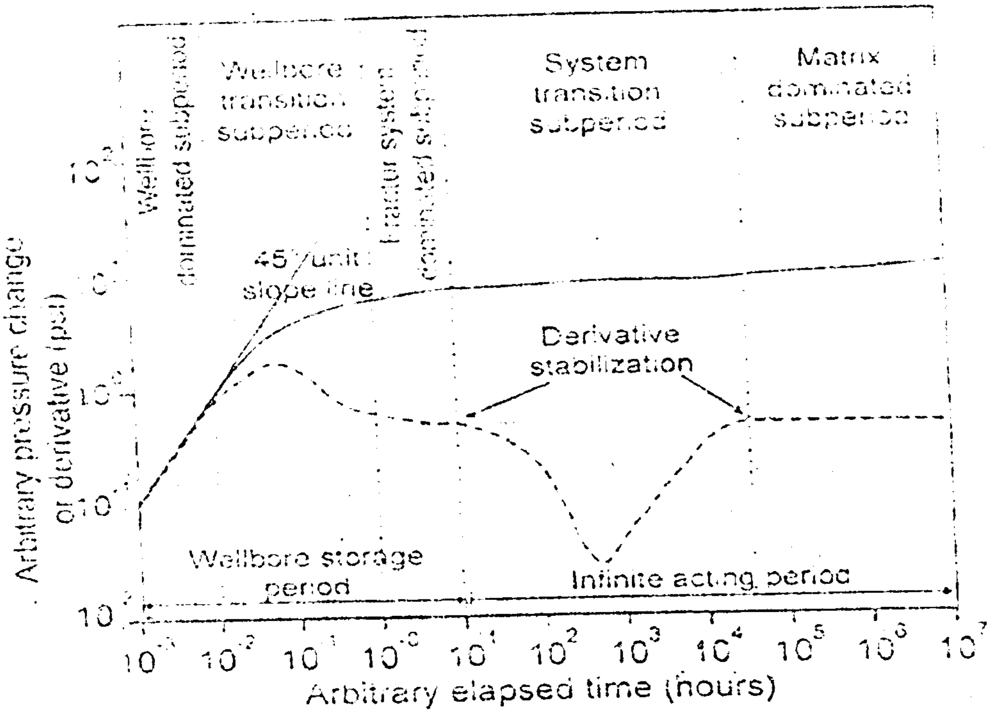


Figure 11.8: Pressure Stages in a well during its Production life

So the resulting derivative profile removes the possibility of an exponential decline with a constant rate. It favours a model with an initial high decline rate followed by a lower decline rate. The profile tends to stabilize corresponding to the derivative stabilization with a hyperbolic decline fit in a period of 4 to 4.5 years as shown in the figure above.

In the production well of this example with a co-mingled production of five seams with varying permeabilities and varying tau values, the system is considered in a tau versus permeability plot.

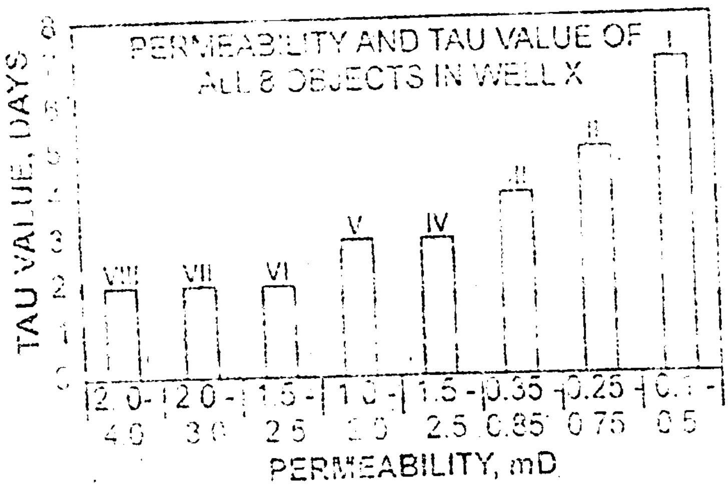


Figure 11.9: Tau values and permeability of the coal seams in well X

A lower tau value signifies smaller cleat spacing, i.e. higher cleat intensity and a higher diffusion coefficient. When regarded in terms of production, a higher permeable seam will desorb faster, attain its peak early and allow the infinite acting period to be dominated by a prolonged production of a high permeable reservoir with peak production of a less permeable reservoir, results in a stable production for a time span of 4 to 4.5 years.
This is different in case of a less permeable sea, because of its higher tau value. The peak production is delayed and the well bore storage is more pronounced. Accordingly, when five seams with different relative permeabilities are allowed to produce together, a case of constant production decline rate is never expected. The interference of a declining production of a high permeable reservoir, results in a stable production for a time span of 4 to 4.5 years.

11.8. Analysis using the Mass Balance Technique

As presented by King (1993), this technique incorporates the effects of gas desorption from the coal matrix as well as dynamic changes in gas and water permeability in the coal fractures. To use this technique a "Material balance simulator" was programmed. It is not widely used for production analysis and forecasting of coalbed methane wells. This technique is theoretically sound within the boundary, of the assumption used to generate the solutions. The technique is useful for validating recovery calculations, generated by reservoir simulators, and for estimating well performances of mature producing fields in which sufficient reservoir data is available. The assumptions inherent in the material balance technique are as follows (King, 1993):

- It assumes equilibrium between the free gas and adsorbed gas in the reservoir (saturation conditions with respect to the isotherm).
- It requires accurate estimate of key reservoir data such as pressures, desorption isotherm, permeability characteristics etc.
- It assumes pseudo-steady state desorption characteristics
- It models well bore damage or stimulation using, skin factors (not applicable for hydraulically fractured wells).

In the present technique, developed by Seidle(1991) and Yee et al. (1993), a coalbed methane reserve has to reach the dewatered phase, which is defined by:

- A declining gas production rate trend (outer boundary dominated, pseudo-steady state flow), and
- Changes in the relative permeabilities of gas and water in the reservoir.

This technique combines a coalbed methane material balance equation with a gas deliverability equation, to forecast gas production rates. The technique is used on the production data of an example well (Well Y).

Equation 16 is used to calculate the gas flow rate (q_g).

$$q_g = \frac{K_g h[m(avg.p) - m(p_{wf})]}{1{,}422T[1n\ r_e/r_w - {}^3/_4 + s + Dn_D qg]} \qquad \text{(eq. 11.16)}$$

where :

K_g is the effective permeability to gas (md), h the thickness, $m(avg.p)$ the real gas pseudo-pressure, which corresponds to the average reservoir pressure (psi^2/cp), $m(pwf)$ the real gas pseudo-pressure, which corresponds to the bottom hole pressure (psi^2/cp). T is the reservoir temperature (R), re the drainage radius (ft), s the well bore skin factor and Dn_D non-Darcy flow coefficient (D/MScf).

The real gas pseudo-pressure in equation 16 changes with the average reservoir pressure at every point of time.

$$M(p) = 2\int_{pb}^{p} p/\mu gz\, dp \qquad \text{(eq.11.17)}$$

Where p is the pressure (psi), pb is an arbitrary base pressure, μg is the gas viscosity (cp) and z is the compressibility factor.

The following example illustrates the use of Seidle's analytic technique for long term gas production of the barefoot seam of Well Y (1019.2 to 1049.4 mts.). The following figures show graphically the results of the forecast calculations.

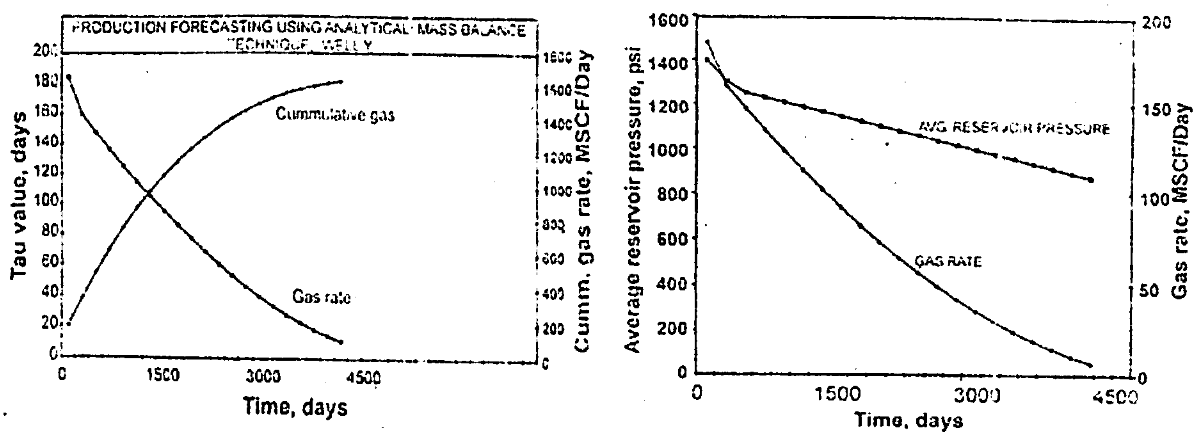


***Figure 11.10**: Results of forecast calculations*

Other than the equations 16, 17, the developed simulator takes into account:

- Gas initially held in the coal cleats.
- Initial absorbed gas in the coal matrix.
- Water influx into and production from the coal fracture system.
- Gas remaining in the coal cleats.
- Gas remaining in the coal matrix.

A combined expression accounts for the cumulative produced gas volume:

$$G_p = [7.758^{*}10^{-3}Ah\emptyset_f(1-S_{wi})1/B_{gi}] + [1.306^{*}10^{-6}Vmp_BAh(bpi/1+bpi)] + [0.001(W_e/B_w - W_p)/avg.Bg] - [7.758^{*}10^{-3}Ah\emptyset_f(1-S_{wi})1/B_g] - [1.360^{*}10^{-6}V_m\rho_BAh(bavg.p/1+bavg.p)]$$

Chapter 12: MAIN DIFFERENCE BETWEEN A COAL SEAM AND A CONVENTIONAL DUAL POROSITY GAS RESERVOIR

Table 12.1: The main difference between a coal seam and a conventional dual porosity gas reservoir

Characteristics	Conventional gas Reservoir	Coal Seams
Dual porosity	Joints, fissures, solution channels and vagular voids represent the natural fracture system where the fractures are randomly spaced.	The cleat system represents the natural fractures, which are uniformly spaced, and these cleats give the discrete nature of coal.
Gas Storage	Free gas is stored in porous medium.	Little or no free gas is adsorbed on the surface of coal particles.
Transport Mechanism	Flow is laminar caused by a pressure gradient and it obeys the Darcy's law. Turbulent flow may occur near the well bore.	Flow is diffusion in the matrix, caused by a concentration gradient. Pressure gradient then cause flow in cleats.
Production Performance	Gas rate starts with a maximum and then decreases with time. Initially, little or no water is produced and gas/ water ratio decreases with time.	Gas rate increases with time until it reaches a maximum and then decreases.
Mechanical Properties	Generally well bore stability is not a problem. Young's modulus is in the range of 10^{6} psi. Pore compressibility is in the range of $10^{0.6}$ psi.	Coal is weak and fragile because of the cleat structure which causes well bore stability problems. Young's modulus is in the range of $10^{0.4}$ psi. Pore compressibility is in the range of $10^{0.4}$ psi.
Reservoir Properties	Reservoir properties such as porosity and permeability do not vary significantly.	Reservoir properties vary significantly.

Chapter 13: SCREENING CRITERIA FOR A CBM PROJECT

Table 13.1: Threshold values for potential CBM targets

Sr. No.	Critical Parameters	Threshold Values/ Range
01.	Depth (m)	300-1200
02.	Cumulative coal thickness (m) and coal seam thickness (m)	As high as possible and >4
03.	Vitrinite Reflectance (VR_O max)	>0.73
04.	Ash content (%)	5-15
05.	Coal Composition	Vitrinite rich
06.	Methane Content	>8.5cc/gm or 300scf
07.	Methane Saturation (Desirable)	>50%
08.	Cleat Frequency	Vitrian bands should be cleated
09.	Permeability (md) (Desirable)	0.3-10

Chapter 14: EXPERIMENT - PROXIMATE ANALYSIS

14.1. Aim:

To determine the ash content, moisture content, volatile matter, fixed carbon and volatile matter on dry ash free basis of coal samples by proximate analysis.

14.2. Theory:

1. Proximate Analysis; Proximate analysis is used in the case of coal and coke; the determination by prescribed methods of moisture, ash, volatile matter and fixed carbon (by difference). The term proximate analysis has evolved from approximate analysis which in earlier days meant that, the analytical procedures are neither standardized nor precise. Today, while analytical procedures used in proximate analysis are empirical and they are precise if carried out by prescribed method.
2. Moisture; Moisture refers essentially water. Its quantity is determined by prescribed method which may vary according to the nature of material.
3. Ash; It is the inorganic residue remaining after ignition of combustible substance determined by definite prescribed methods.
4. Volatile Matter; Refers to those products, exclusive of moisture, given off by a material as gas r vapor determined by prescribed methods which may vary according to the nature of the material.
5. Fixed Carbon: Fixed carbon in case of coal or coke and sub bituminous material is the solid residue other than ash obtained by destructive distillation by definite prescribed methods.

14.5. Observations:

Sr. No.	Moisture and Ash Content									Volatile Matter and Fixed Carbon							
	Wt. of empty crucible	Wt. of crucible + sample before heating	Wt. of sample before heating (a)	Wt. of crucible + sample after heating to 105°C	Wt. of sample after heating to 105°C (b)	M/C (a-b) / a *100 (%)	Wt. of crucible + sample after heating to 725°C	Wt. of sample after heating to 725°C (c)	Ash Con -tent c/a *100 (%)	Wt. of crucible + lid	Wt. of crucible + lid + sample before heating	Wt. of sample before heating (d)	Wt. of crucible + lid + sample after heating	Wt. of sample after heating (e)	VM Con - tent (d-e/ d) *100 – M/C (%)	VM dry ash free basis	FC (%)
01.	23.5949	24.5951	1.0002	24.4642	0.8693	13.09	23.6694	0.0745	7.45	26.9899	27.9902	1.0003	27.3239	0.3340	53.52	67.35	25.94
02.	23.2811	24.2812	1.0001	24.1495	0.8684	13.17	23.3099	0.0288	2.88	27.5045	28.5046	1.0001	27.8683	0.3637	50.46	60.11	33.49
03.	18.6959	19.6962	1.0003	19.5764	0.8805	11.98	18.7813	0.0854	8.54	27.7787	28.7791	1.0004	28.2302	0.4515	42.89	53.96	36.59
04.	23.4293	24.4294	1.0001	24.2548	0.8255	17.46	23.4497	0.0204	2.04	27.3988	28.3992	1.0004	27.8240	0.4252	40.04	49.74	40.46

Where:

M/C: Moisture content

VM: Volatile Matter

FC: Fixed Carbon

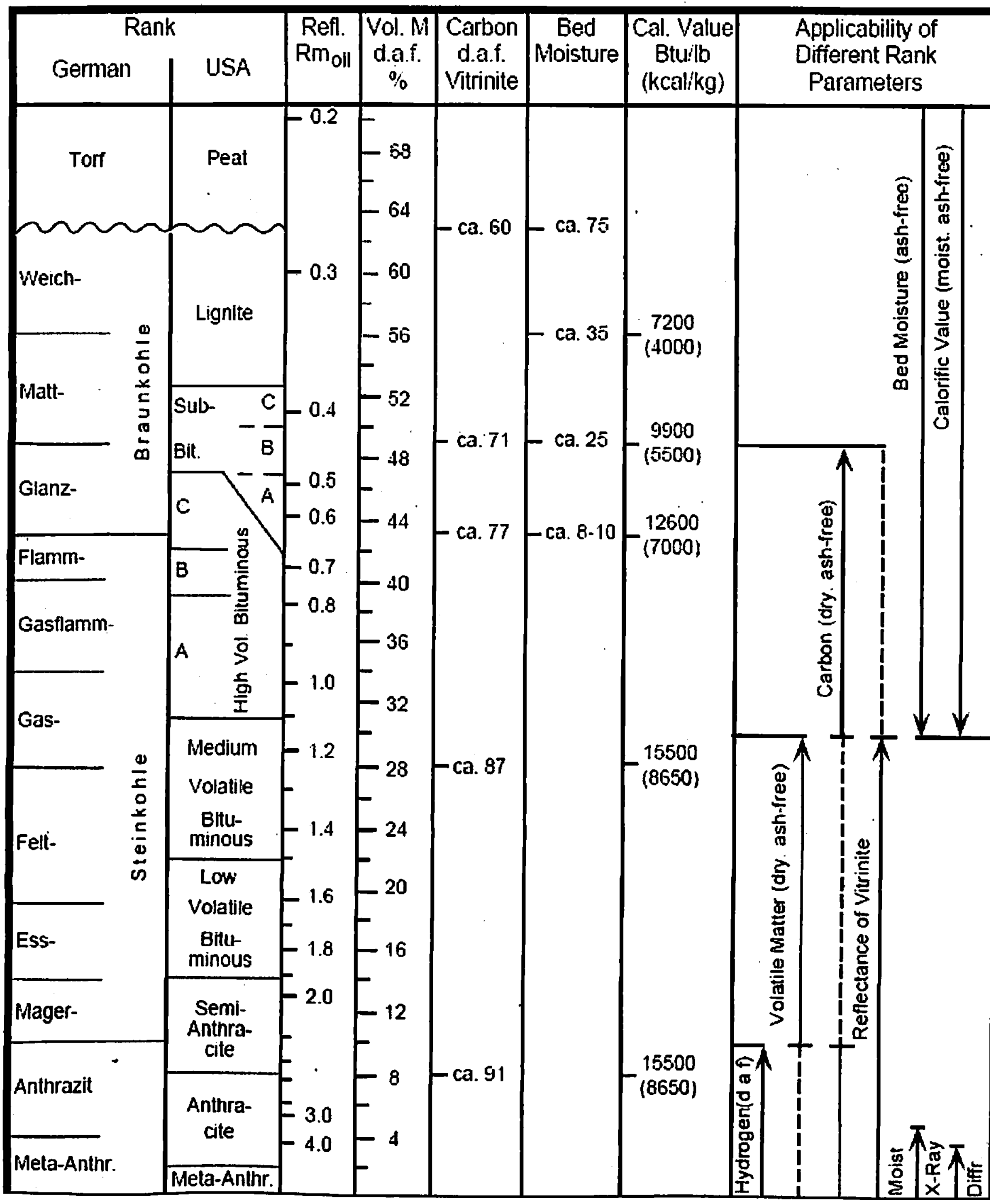


Figure 14.1: Chart for gas content estimation

14.4. Procedure:

1. Measure the weight of empty crucible containers.
2. Measure one gram of crushed coal sample. Note down the weight of the crucibles and the samples.
3. Set the oven at a temperature of about 105°C (100°C-110°C).
4. Place the crucibles with the samples in the oven for one hour.
5. Remove the samples from the oven and place them in desiccators to cool for about ten minutes.
6. Weigh the samples and note down the readings.
7. Next, set the oven at 725°C (700-750°C).
8. Place the samples.
9. Heat the samples to redness and complete ignition.
10. Weigh the samples and note down the readings.
11. Now weigh four empty crucibles with their lids and note down the readings.
12. Weigh one gram of each sample.
13. Heat the oven to 960°C (950 ± 20°C).
14. Place the crucibles with their lids and the samples in the oven for 7mins.
15. Place the samples in the desiccators and cool them. Weigh the samples and note the readings.

14.5. Calculations:

1. Moisture Content (%) = (a-b)/a *100

Where: a – Wt. of sample before heating

b – Wt. of sample after heating to 105°C

2. Ash Content (%) = c/a *100

Where: a – Wt. of sample before heating

c – Wt. of sample after heating to 725°C

3. Volatile Matter (%) = (d-e)/d * 100 – M/C

Where: d – Wt. of sample before heating

e – Wt. of sample after heating at 960°C

M/C – Moisture Content (%)

4. Volatile Matter (dry ash free basis) = Volatile Matter *100/[100- (ash + Moisture content)]
5. Fixed Carbon (%) = 100 - (moisture + ash + volatile matter)

14.6. Result:

Table 06: *Results of proximate analysis*

Sr. No.	M/C Content	Ash Content	VM	FC
01.	13.09	7.45	67.35	25.94
02.	13.17	2.88	60.11	33.49
03.	11.98	8.54	53.96	36.59
04.	17.46	2.04	49.74	40.46

The chart given in page 59 is used to find the rank of coal from which the gas content can be estimated. Comparing the result obtained with the chart we know that the coal is bituminous.

Chapter 15: Generalized Material Balance Equation

The material balance equation is the fundamental tool for estimating the original gas in place "G" and predicting the recovery performance of conventional gas reservoirs. For conventional gas reservoirs, the MBE is expresses by the following linear equation:

$$\frac{P}{Z}=\frac{P_i}{Z_i}-\frac{(P_{SC}T)}{T_{SC}V}G_P$$

The great utility of the P/Z plots and the ease of their constructions for conventional gas reservoirs have led to many efforts, in particular the work of King (1993) and Seidle (1999), to extent this approach to unconventional gas resources such as coalbed methane.

The material balance equation for CBM can be expressed in the following generalized form:

$$G_P = G + G_F - G_A - G_R \qquad \text{(eq. 15. 01)}$$

Where:

G_P = cumulative gas produced, scf

G = gas originally adsorbed, scf

G_F = original free gas, scf

G_A = gas currently adsorbed, scf

G_R = remaining free, scf

For a saturated reservoir (i.e. initiak reservoir pressure pi = desorption pressure pd) with no water influx, the four main components of the right hand side of the above equation can be determined individually as follows:

15.1. Gas originally adsorbed "G":

In terms of the coal density ρ_B and the initial gas content G_C, the gas in place "G" is given by:

$$G = 1359.7\ Ah\ \rho_B\ G_C \qquad \text{(eq. 15.02)}$$

Where:

ρ_B = bulk density of coal, gm/cc^2

G_C = gas content, scf/ton

A = Drainage area, acres

h = Average thickness, ft

15.2. Original free gas "G_F":

The initial free gas that occupies the coal cleats and natural fracture system is expressed by:

$$G_F = Ah\ \varnothing\ (1-S_{wi})\ E_{gi} \qquad \text{(eq. 15.03)}$$

Where:

G_F = original free gas in place, scf

S_{wi} = initial water saturation

$\varnothing$ = porosity, fraction

E_{gi} = gas expansion factor at p_i in scf/ bbl given by:

$$E_g = \frac{198.6 p_i}{TZ_i}, \text{ scf/bbl}$$

15.3. Gas Currently Adsorbed "G_A":

The gas stored by adsorption at any pressure "p" is typically expressed with the adsorption isotherm or mathematically by Langmuir's equation as:

$V = V_m\ (bp/1+bp)$

Where:

V = volume of gas currently adsorbed at "p", scf/ ton

V_m = Langmuir isotherm constant, scf/ ton

p = current pressure, psia

b = Langmuir pressure constant, $psia^{-1}$

The volume of the adsorbed gas "V" as expressed in scf/ ton at reservoir pressure "p" can be converted into scf by the following relationship:

$$G_A = 1359.7\ A\ h\ \rho_B\ V \qquad \text{(eq. 15.04)}$$

Where:

G_A = adsorbed gas at p, scf

V = adsorbed gas at p, scf/ ton

15.4. Remaining Free Gas "G_R":

During the dewatering phase of the reservoir, formation compaction (matrix shrinkage) and water expansion will significantly effect water production. Some of the desorbed gas remains in the coal cleat system and occupies a pore volume that will be available with water production. King (1993) derived the following expression for calculating the average water saturation remaining in the coal cleats during the dewatering phase:

$$S_W = \frac{S_{wi}\,[1 + c_w\,(p_i - p)] - \dfrac{B_W W_P}{7758Ah\O}}{1 - (p_i - p)\,c_f} \qquad \text{(eq. 15.05)}$$

Where:

p_i = initial pressure, psi

W_P = cumulative water produced, STB

B_W = water formation volume factor, bbl/STB

A = drainage area, acres

c_w = isothermal compressibility of water, $psia^{-1}$

c_f = isothermal compressibility of the formation, $psia^{-1}$

S_{wi} = initial water saturation, fraction

Using the above estimated average water saturation, the following relationship foe the remaining gas in cleats is developed:

$$G_R = 7758\,A\,h\,\O \left[\frac{\dfrac{B_W W_P}{7758Ah\,\O} + (1-S_{wi}) - (pi-p)\,(c_f + c_w S_{wi})}{1 - (p_i - p)\,c_f}\right] E_g \qquad \text{(eq. 15.06)}$$

Here GR is the remaining gas at pressure p, scf.

Substituting equations 15.02-15.06 in equation 15.01 and rearranging gives:

$$G_P + B_W W_P E_g = Ah[1359.7\,\rho_B\{G_C - V_m\,(b_p/1+b_p)\,E_g\} - 7758(1-S_{wi})E_{gi}] + 7758Ah\O\,(1-S_{wi})E_{gi}$$

The equation is in the form of a straight line y = mx + a.

15.5. Example of use of material balance equation:

Table 15.1: Given data of a field

Langmuir's Pressure Constant	b = 0.00276 psi^{-1}
Langmuir's Volume Constant	V_m = 428.5 *scf/ton*
Average Bulk Density	ρ_B = 1.70 gm/cm^3
Average Thickness	h = 50 *ft*
Initial Water Saturation	S_{wi} = 0.95
Drainage Area	A = 320 *acres*
Initial Pressure	p_i = 1500 *psia*
Critical (desorption) Pressure	p_d = 1500 *psia*
Temperature	T = 105°F
Initial Gas Content	G_c = 345.1 *scf/ton*
Formation Volume Factor	B_w = 1.00 bbl/STB
Porosity	ϕ = 0.01
Water compressibility	c_w = 3 x 10^{-6} psi^{-1}
Formation compressibility	c_f = 6 x 10^{-6} psi^{-1}

$x = Ah[1359.7\ \rho_B\{G_C - V_m\ (b_p/1+b_p)\}\ E_g]$

$V = V_m\ (bp/1+bp)$

b= Langmuir's pressure Constant

$= 0.00276 psia^{-1}$

V_m = Langmuir's Volume Constant

= 428.5 scf/ton

$$V = \frac{1.18266p}{1+0.00276p}\ \text{Scf/ton}$$

$x = 2322.66(345.1 - V) - 3.879E_g$

Table 15.2: Material balance equation calculations

Given					Calculated		
Time Days	G_p MMscf	W_p MSTB	P Psia	Z	p/Z psia	E_g Scf/bbl	$V = \frac{1.18266p}{1+0.00276p}$ Scf/ton
0	0	0	1500	0.8800	1704.5	599.21	345.097
730	265.086	157.490	1315	0.8774	1498.7	526.87	335.90
1460	968.41	290.238	1021	0.8995	1135.1	399.04	316.23
2190	1704.033	368.292	814.4	0.9173	887.8	312.11	296.53
2920	2423.4	425.473	664.9	0.9311	714.1	251.04	277.33
3650	2992.901	464.361	571.1	0.9400	607.5	213.57	262.14

Table 15.3: Material balance equation calculations

Values Given			Calculated Values			
P Psia	W_p MMSTB	Gp MMscf	V Scf/ton	E_g Scf/bbl	$y=G_p+W_pE_g$ MMscf	$x=2322.66(345.1-V)-3.879E_g$
1500	0	0	345.097	599.21	0	0
1315	0.15749	265.086	335.90	526.87	348.06	19310
1021	0.290238	968.41	316.23	399.04	1084.23	65494
814.4	0.368292	1704.033	296.53	312.11	1818.98	111593
664.9	0.425473	2423.4	277.33	251.04	2530.21	156425
571.1	0.464361	2992.901	262.14	213.57	3092.07	191844

Table 15.4: Material balance equation calculations

$y=G_p+W_pE_g$ MMscf	$x=2322.66(345.1- V)- 3.879E_g$
0	0
348.06	19310
1084.23	65494
1818.98	111593
2530.21	156425
3092.07	191844

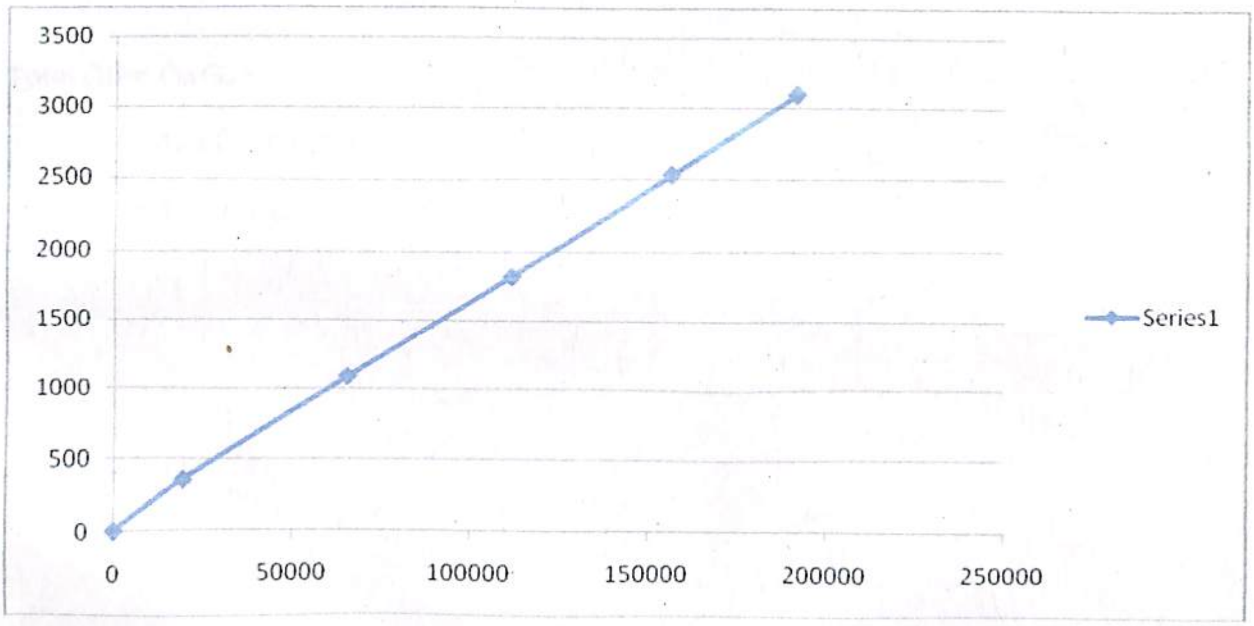


Figure 15.1: Graphical representation of material balance equation

Slope of the curve = 15900 acre-ft

m = Ah

A= m/h= 15900/50= 318 acre

Original gas in place from material balance equation

G = Gas originally adsorbed

$= 1359.7 Ah\rho_B G_C$

$= 1359.7(318)(50)(1.7)(345.1)$

= 12.68 bscf

G_F = Original free gas

$= 77.58 Ah\varnothing(1-S_{wi})E_{gi}$

$= 77.58(318)(50)(0.01)(0.05)(599.2)$

= 0.0369bscf

Total GIP= $G+G_F$

= 12.68 + 0.0369

= 12.72 bscf

Chapter 16: Volumetric Estimation

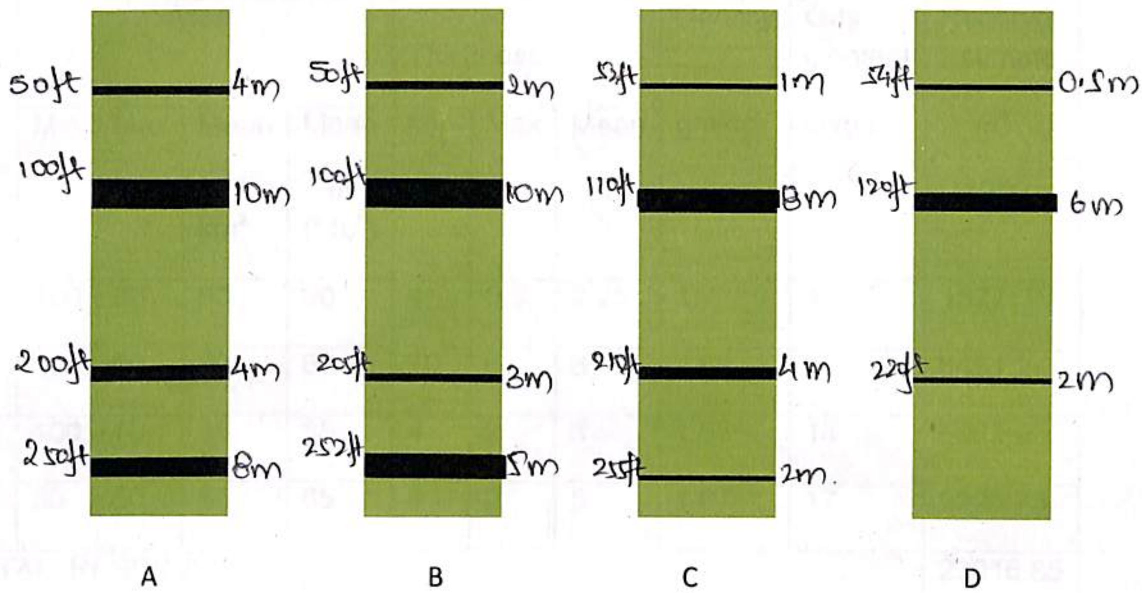
A fictitious field has been created to carry out the volumetric estimation for a CBM reservoir. The field is shown in the next page. Four exploratory wells are shown to be drilled to carry out exploration – A, B, C and D. The reservoir has four coal seams, three of which are continuous throughout the reservoir and one is not. The total area of the field is assumed as $100 km^2$. The desorption studies data of the various coal seams is as given below:

Table 16.1: GAS CONTENT FROM DESORPTION STUDIES

Sr. No.	Sample Details	Gas Content cc/gm	Depth ft	Mean Value cc/gm
01.	A1	2	50	
02.	B1	4	50	4
03.	C1	6	52	
04.	D1	4	54	
05.	A2	10	100	
06.	B2	8	100	6
07.	C2	4	110	
08.	D2	2	120	
09.	A3	14	200	
10.	B3	16	205	14
11.	C3	14	210	
12.	D3	12	220	
13.	A4	15	250	
14.	B4	17	252	17
15.	C4	19	255	

Sample A1 represents the coal sample from the first seam of well A, B1 represents the coal sample of the first seam from well B and so on.

Exploratory Wells



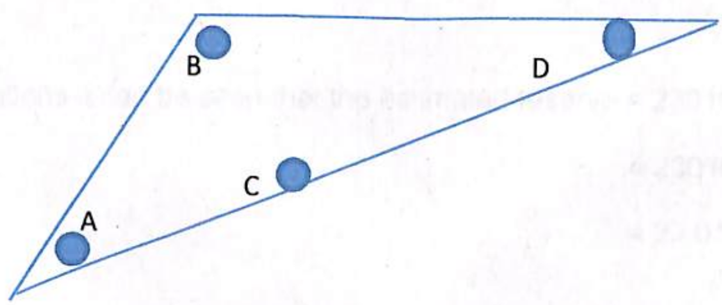


__Table 16.2__: VOLUMETRIC ESTIMATION

Sr. No.	Area				Thickness			Density	Gas Content	Reserve Estimate
	Min	Max	Mean km^2	Mean m^2 (*10^6)	Min	Max	Mean m	gm/cc	cc/gm	m^3 (*10^6)
01.	100	80	90	90	4	0.5	2.25	1.7	4	1377
02.	100	60	80	80	10	6	8	1.68	6	6451.2
03.	100	70	85	85	4	2	3	1.67	14	5961.9
04.	80	50	65	65	8	2	5	1.67	17	9226.75
TOTAL RESERVES										23016.85

From the above calculations it can be seen that the estimated reserve = 23016.85 *10^6m^3

= 23016.85 Mm^3

= 23.017 Bm^3

Chapter 17: COMPARISION OF PRODUCTION DECLINE DATA AND RESERVE ESTIMATION

For the comparison a well from the Jharia basin is considered.

17.1. Production Decline Data

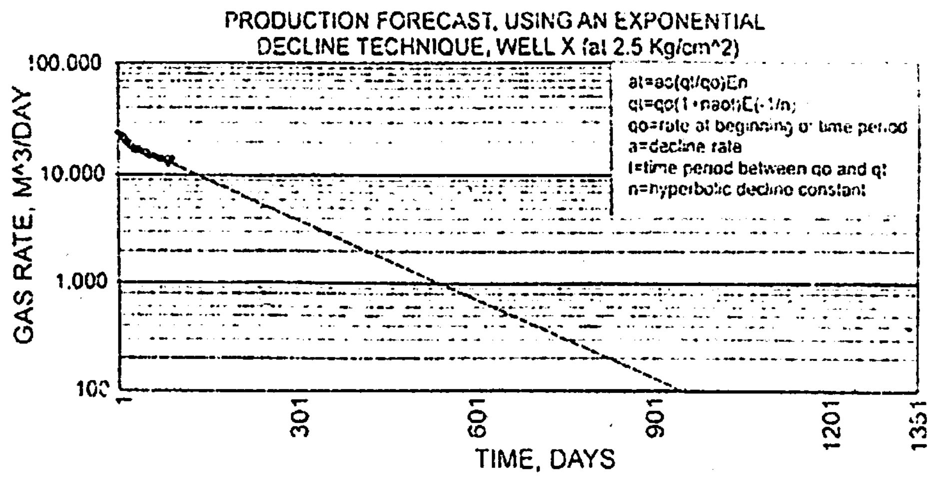


***Figure 17.1**: Exponential production decline curve*

From graph, q_0=20,000 m3/day

q_1= 100m3/day

Production decline equation for exponential decline is

$$a = \frac{\ln q_0 - \ln q_1}{t}$$

$$= \frac{\ln 20{,}000 - \ln 100}{903}$$

$$= 5.867 \times 10^{-3}$$

$$G_p = \frac{q_0 - q_1}{a}$$

$$= \frac{20{,}000 - 100}{5.867 * 10^{-3}}$$

$= 3.39 * 10^6$

$= 3.39 Mm^3$

Thus the cumulative production from the well is $3.39 Mm^3$.

17.2. Cumulative production from reserve estimation

Area of well = $0.4 km^2$

Thickness of seam = 1.28m

Gas Content = 279.66 scf/ton = 9.8 cc/gm

Density = 1.3 gm/cc

Reserve = $0.4 * 10^6 * 1.28 * 9.8 * 1.3$

$= 6.523 * 10^6$

$= 6.523 Mm^3$

Recoverable Reserves = Estimated Reserves * Recovery Factor

= 6.523*68.7%

$= 4.48 Mm^3$

Percentage error = $\frac{\text{Recoverable reserves} - \text{Recovered Reserves}}{\text{Recoverable Reserves}}$

$$= \frac{(4.48 - 3.39) * 100}{4.48}$$

= 24.33%

Chapter 18: CONCLUSION

Oil has been the major source of energy for the past many decades. But the formation of oil is much slower a process as compared to its consumption. Due to theis there is an ever increasing gap between energy and supply. It is important that new energy sources be tapped and extracted efficiently. Now the demand for gas is rising. Coalbed methane gas is an unconventional source of gas. In India there is high potential for CBM. A CBM project is very risky. The production of gas starts much after the production of water, and it might so happen that the production of gas is very less. It is thus very important to first estimate the reserves as accurately as possible and then exploit the CBM with efficient and economic methods. Gas content of the coal seams must be estimated as it is the most important parameter deciding the reserves. The methods mentioned in the report are used for the reserve estimation of CBM. CBM has the potential to decrease the energy gap to some extend. It is high time that CBM is given importance.

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