Fundamentals of COALBED METHANE *Reservoir Engineering*

PennWell®

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Preface

Coalbed methane developed from a safety hazard in coal mines to an unconventional gas reservoir in the last quarter of the 20th century. Many articles dealing with coal geoscience and reservoir engineering have been written over the last 30 or 40 years, and the field is now sufficiently mature that several good textbooks and monographs on these subjects have appeared. Why add another? Three reasons. First, coalbed methane can now be differentiated into separate specialties such as geology, geochemistry, geophysics, drilling and completions engineering, and operations and facilities engineering in addition to reservoir engineering. Secondly, the coalbed methane industry is increasingly global, allowing regional perspectives of previous work to be fused into a larger vision. Lastly, coalbed methane reservoir engineering has evolved many specialized methods in recent years. Entry into the field could perhaps be eased by a book stressing the fundamental aspects of coal gas reservoir engineering.

This book is not meant to be an exhaustive compilation of all coalbed methane reservoir engineering, a rapidly evolving field. It is meant to be a useful introduction to a unique unconventional gas resource for students and practicing engineers as well as a basic handbook for those involved in coalbed methane on a daily basis and require straightforward, practical answers in the fast-paced business world. I am grateful to all the people who have assisted me in bringing this book to completion, but all errors remain mine and mine alone. I will consider this book successful to the extent that it promotes additional developments in coalbed methane reservoir engineering that render it obsolete.

Introduction 1

What Is Coal Gas?

Coals were among the first gas reservoirs to be discovered and among the most recent to be exploited. Coal outcrops provided solid fuel to various early human societies, but gas held in coal deposits was unrecognized. Only when mines were driven deeper into coal deposits were gas emissions encountered, all too frequently with tragic results when the gas exploded. This gas was considered one of the many hazards of coal mining, with no thought given to capturing it for beneficial use even after exploitation of conventional oil and gas reservoirs began. Coalbed methane evolved from safety concerns in gassy coal mines, and initial coal gas geoscience and reservoir engineering concepts were rooted in this mining perspective. Only in the last generation has coal gas, along with shale gas and tight formation gas, been recognized as an unconventional gas resource. Like other unconventional gas resources, coal gas is a diffuse, heterogeneous, areally extensive resource defined by distribution and maturity of source rock, seal integrity over geological time, and occasionally by conventional traps.

Gas is generated during maturation of organic matter into coal and by microbes residing in a coal. Coal deposits of all geologic ages have generated gas, the volume increasing with coal rank. The belated development of coal gas is perhaps due to its capricious behavior, which is related to its unique storage in coal. Conventional gas is compressed into the pore space of the host reservoir rock and will easily flow to a pressure sink such as a wellbore. In contrast, the majority of the gas in a coal is typically *sorbed*, or attached to the surface of the coal itself. Coals are naturally fractured reservoirs, and the fractures, termed *cleats*, are often filled with water. Coal deposits are usually aquifers with the hydrostatic pressure of the water in the cleats holding the gas on the matrix of the coal, thereby providing the seal for this unconventional reservoir. Reduction of pressure in a coal seam by a mine shaft or wellbore will first mobilize water in the cleats, followed by gas desorbed from the matrix. Removal of this water can be costly and has bankrupted more than one attempt to produce coal gas. Only recently has coal water been recognized as a valuable natural resource rather than as oilfield brine, and future coal gas development projects should expect increased regulatory constraints on water production and disposal.

Pressure reduction in a coal seam sufficient to liberate gas from the matrix into the cleats initially results in a low gas saturation and, hence, low gas mobility and low initial gas production rates from a well. With continued dewatering of the coal deposit, gas saturation in the cleats increases, leading to increasing gas mobility and gas production rates. This rising gas production rate, a behavior opposite to that of conventional gas reservoirs, has been termed *negative decline*. Caused by the interplay between dewatering and depressuring of a coal deposit, duration of this negative decline period and the resulting peak gas production rate remain difficult to predict a priori. Gas rates can increase by a factor of 2 to 10 over a dewatering period, which can last from months to years. Examples of rapid and slow negative declines are illustrated in figures 1–1 and 1–2, respectively. After the gas production rate from a well or field has peaked and shows a clear decline, future performance and remaining reserves are often predicted with a combination of decline curve analysis, well performance analysis, and reservoir simulation.

dewatering time =	12	months
initial gas rate =	1	mcfd
incline time =	12	months
plateau rate =	220	mcfd
plateau duration =	12	months
EUR =	300	mmcf

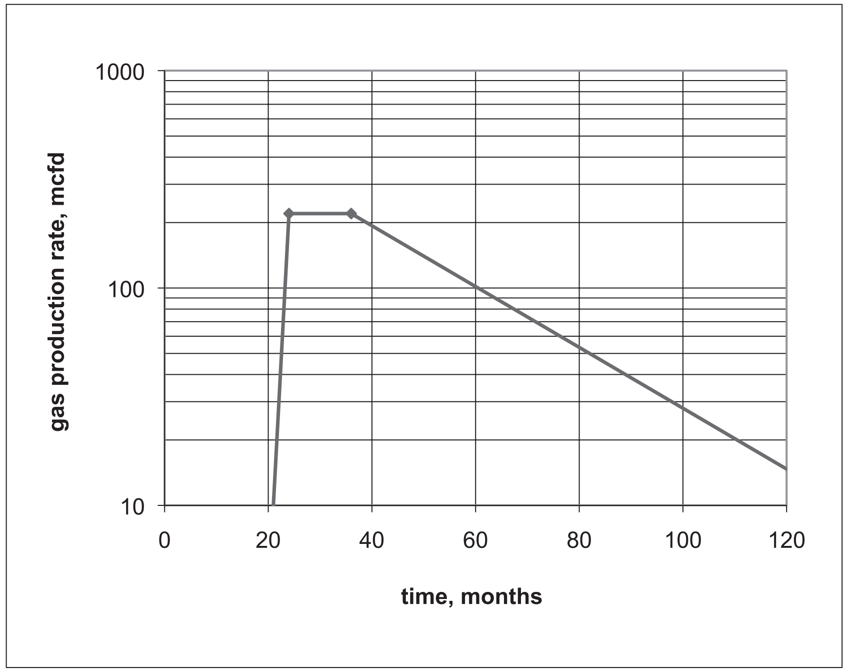

Fig. 1–7. Powder River Basin Big George coal type curve[6]

initial gas rate =	150	mcfd
decline rate =	0.2262	yr-1
De =	20.2%	%/yr
EUR =	240	mmcf

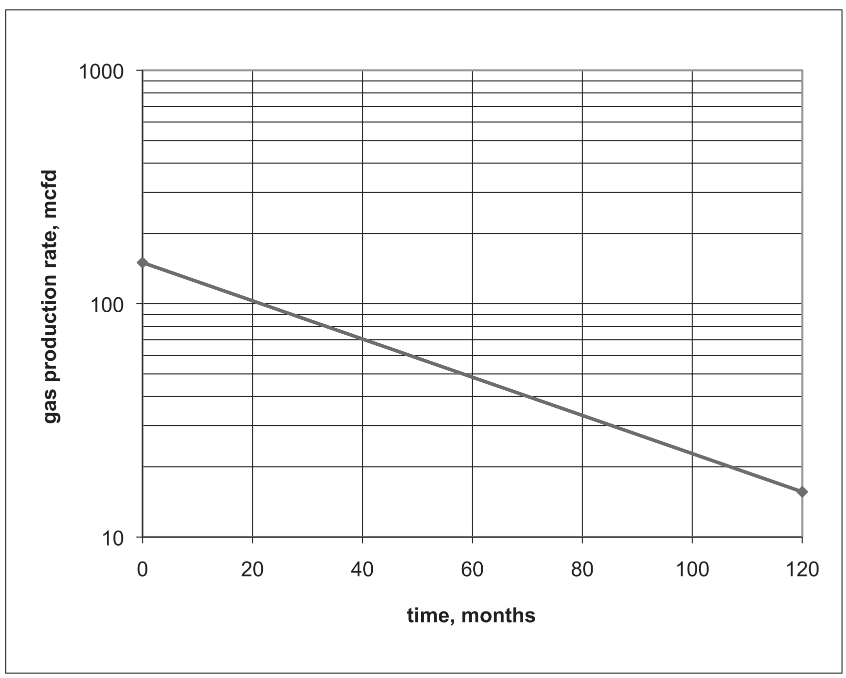

Fig. 1–8. Horseshoe Canyon coal type curve[7]

Similarly, time required to desorb 95% of the gas is

$$t_{95} = \frac{0.253118}{0.055743}\tau = 4.54\tau$$

Time required to release 95% of the gas from this sample is therefore

$$t_{95} = 4.54(54.8 \text{ hr}) = 248.8 \text{ hr} = 10.4 \text{ days}$$

Coal permeabilities in the Powder River Basin are on the order of several hundred millidarcies, making time required for this well to reach pseudosteady-state flow on the order of one to two weeks. As response times of matrix and cleat are roughly equal, well behavior is controlled by the interplay between gas release from the matrix and gas flow in the cleats.

Recent years have seen increasing interest in enhanced coalbed methane recovery (ECBM) via injection of nitrogen, CO_2, and flue gas, and in CO_2 sequestration. On a field or well scale, uptake of injected gases onto the coal matrix can be described by the mathematics developed above. For short injection times and in the near-wellbore region, additional mathematical sophistication is required. For example, Clarkson and Bustin studied the effect of pore structure and gas pressure on the sorption behavior of methane and CO_2 on samples of Cretaceous coals from the Gates Formation in Western Canada.[91]

Coal Rock Properties

As a reservoir rock, coal is more reactive than conventional reservoirs in both a mechanical and a chemical sense. Conceptualizing coal as a polymeric tangle of organic filaments, the ability of conventional rock mechanics to describe coal stress loads and the resultant deformations is surprising. Coal rock properties show little dependence on geologic age, varying primarily with rank, lithotype (maceral composition), and quality (ash and mineral matter). As coal quality is strongly influenced by local depositional events, coal rock properties can show extreme areal heterogeneity. Levine noted the dual problems of sample selection and scale dependence, which complicate measurement of coal rock properties.[92] Intact portions of coal cores sufficiently large for rock properties measurements may have survived the coring process due to anomalous mechanical behavior. Rock properties of a coal seam, with multiple heterogeneities and a thickness many times larger than the cleat spacing, may differ from those measured on laboratory samples. Typically the laboratory samples are more homogeneous and have fewer cleats. Rock properties important for coal gas reservoir engineering include Young's modulus, Poisson's ratio, unconfined compressive strength, and cleat compressibility.

Young's modulus is defined as the ratio of stress to strain of a sample subjected to uniaxial loading, and values for coals reported by several workers are collected in table 2–11.

While this list is not exhaustive, it does illustrate the variation seen in this important rock property. Several investigators noted that Young's modulus of a coal increases with ash fraction, and Levine suggested this parameter measured parallel to bedding planes is larger than perpendicular to bedding.[93] Reviewing Young's moduli reported for coals of bituminous rank and higher, Bromhal et al. noted the value of this parameter measured parallel to the bedding planes averaged 22% greater than that measured perpendicular to bedding planes. The average value of Young's modulus was 511,000 psia (3,500 MPa).[94] Young's moduli reported for coals are one-third to one-tenth that of sandstone and limestones and are approximately equal to that of weak shales. Until Young's modulus can be measured for a specific seam, a value of 500,000 psia (3,400 MPa) is often assumed.

Poisson's ratio is defined as the ratio of lateral strain to axial strain of a sample subjected to uniaxial loading. Typical values of Poisson's ratio reported for coals are collected in table 2–11, which is not comprehensive but does illustrate the variation of this rock property in coal. The range of Poisson's ratio seen in coals, from 0.2 to 0.4, is similar to that seen in sandstones and shales and somewhat greater than that of limestones. Lacking measured values of Poisson's ratio for a particular coal, a value of 0.3 is often employed.

Coal Cleats

Coals are unique, naturally fractured reservoirs with two sets of mutually perpendicular fractures, both of which are perpendicular to the bedding planes. As discussed in chapter 2, the dominant set of roughly parallel, throughgoing, extensive fractures is termed face cleats. The second set of fractures, also roughly parallel but less well developed and often terminating at a face cleat, are called butt cleats. Cleats provide most of the permeability of a coal deposit.

Cleat development depends on coal rank but not geologic age. Lignites and subbituminous coals show sparse, disordered, poorly developed cleats, with cleat spacings on the order of centimeters. Bituminous coals exhibit closely spaced, well-ordered, highly developed face and butt cleats, with fracture spacing on the order of a centimeter or less. Anthracitic coals have fewer, more widely spaced cleats than bituminous coals due to annealing of the fractures as the matrix metamorphoses to a more ordered, planar, graphitic structure. Close noted that cleat spacing in Fruitland coals of the San Juan Basin varied from more than 6 cm in the subbituminous and high-volatile C bituminous coals of the southern portion of the basin to less than 0.6 cm in the high-volatile A bituminous coals along the northern margin of the basin.[67] Again conceptualizing a coal deposit as a collection of matchsticks, permeability is inversely dependent on cleat spacing. Thus, other influences being equal, permeability of Fruitland coals would be expected to vary by an order of magnitude due to rank variations.

Cleats are opening-mode fractures with little, if any, displacement parallel to the cleat walls. Cleats seldom exhibit shearing or deformation. Face and butt cleat spacings are usually equal but are sometimes more intense in the face cleat direction. Although cleat height and length (and usually aperture) are generally much larger than characteristic lengths of coal macerals, cleats are more abundant and better developed in bright, glassy coals rich in vitrinite. The megascopic banding apparent in hand samples of many coals is related to coal lithotype. A detailed explanation of coal lithotypes is given by Mukhopadhyay and Hatcher.[68] Thicknesses of these visual bands (*lithotypes*) are on the order of centimeters and, similar to fractures in conventional rocks, cleat spacing is typically less than lithotype thickness. Some random cleats pass through several bands or lithotypes. These master cleats are better developed than average cleats, with wider apertures and greater lengths. Laubach et al. reported a linear relationship between cleat height and aperture and found cumulative frequency of cleat apertures obeyed a power law distribution.[69] Empirical constants in the equation varied from well to well, indicative of a small length scale for characterizing cleat heterogeneity.

Extension of mathematical relations describing cleat geometries, spacings, and distribution to expressions for calculating permeability of a coal deposit is not yet possible. This could be due to sample volumes being several orders of magnitude smaller than actual drainage volumes, overly simplified equations, and coal heterogeneities.

Several processes are thought to influence cleat formation.[70] Cleats can be considered as dessication-type cracks generated by the expulsion of water in the early stages of maturation. However, dessication cracks are typically polygonal in appearance, not linear. Differential compaction of peats and clastics during burial and lithification could sufficiently stress coal bodies to fail. Although these stresses are primarily compressional, Laubach et al. discussed conditions when they are not and employed geomechanical arguments to demonstrate that all coals should be fractured to some extent.[71] Cleats are sometimes explained as brittle failures caused by deformation of mature coals. This explains the often-observed alignment of face and butt cleats parallel and perpendicular to major fold axes. The interplay of stresses is thought to dictate whether the face or butt cleats are parallel to the fold axis. Close noted that face and butt cleat strikes are nominally parallel and perpendicular to fold axis strikes in the Northern and Central Appalachian, Warrior, Illinois, Arkoma, Powder River, Hanna, Green River, Uinta, Piceance, San Juan, and Raton basins.[72]

Paleostresses during coalification are one of the controls on the constant cleat orientation seen over large portions of some coal basins. Kulander and Dean reported seven cleat domains in the Appalachian coals of West Virginia.[73] Three adjacent domains showed evidence of two cleats sets, but development to date in this basin has not identified these as exceptionally productive areas. Two and possibly three cleat orientations have been identified in the Fruitland coals of the San Juan Basin. Laubach et al. noted the high-productivity fairway of this basin occurs in the transition zone between two cleat orientations, leading to the hypothesis that overprinting

Measurement of Coalbed Gas Content

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Introduction

Determination of the gas volume held in a coal deposit is critical to economic exploitation of that gas. Gas contained in coal deposits was initially considered a mining hazard, and gassy coal mines sought to quantify the amount of gas released per ton of coal mined. Early researchers expressed gassiness of a coal deposit with dimensions of standard cubic centimeters of gas per gram (cm^3/g) or standard cubic feet of gas per ton (scf/ton). Both of these dimensions are still employed in coal gas reservoir engineering today.[1] The two broad categories for gas content determination are direct and indirect methods. *Direct methods* involve collection of fresh coal samples at the wellsite and measurement of gas emitted over weeks or months. *Indirect methods* rely on correlations, equations, or laboratory isotherms (see chapter 5), coupled with the assumption that the coal deposit is fully saturated with gas at the current pressure, to estimate gas content of a coal deposit. Both categories determine sorbed gas; neither determines free gas. This is not a serious limitation for low-porosity, water-saturated coals, but both methods can seriously underestimate the gas resource in high-porosity coals with substantial free gas.

Direct Methods

Initially, coalbed gas contents were determined by measuring the gas released from whole core samples with the objective of improving mine safety. As coals came to be recognized as gas reservoirs, protocols were developed to collect and desorb drill cuttings and sidewall cores in addition to whole cores. In parallel, mathematical models to analyze desorption data were developed. All models assume gas release from the coal sample is controlled by desorption, not flow in the cleats. Currently, the following are the three most popular methods for analysis of desorption data:[2]

1. The U.S. Bureau of Mines direct method
2. The Smith and Williams method
3. Curve fit methods

It should be noted that any of the three methods can be applied to desorption data from cores, cuttings, or sidewall cores. With three types of desorption samples and three methods of analyzing desorption data, there are nine avenues to measure coalbed gas content. In theory, none are fundamentally flawed, and all nine should give the same answer. In practice, however, accuracy of the methods varies, and each has its unique limitations. The current industry standard for gas content determination is desorption of whole core samples maintained at reservoir temperature and analysis of the data according to the U. S. Bureau of Mines (USBM) direct method.