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Hydrogeologic factors affecting gas content distribution in coal beds

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Abstract

Gas content in coal is not fixed but changes when equilibrium conditions within the reservoir are disrupted. Therefore, gas content distribution in coal varies laterally within individual coal beds, vertically among coal beds in a single well, and within thicker coal beds. Major hydrogeologic factors affecting gas content variability include gas generation, coal properties, and reservoir conditions. Gas generation affects gas content variability on a regional scale, whereas coal properties influence gas content distribution on a regional and local scale. Reservoir conditions affect gas content more locally within specific fields or individual wells. The potential for high gas content is controlled directly by the amount of thermogenic and secondary biogenic gases generated from the coal which in turn are controlled by burial history, maceral composition, and basin hydrodynamics. Variability in mineral matter (ash) and moisture content, sorption behavior among macerals, diffusion coefficients, and permeability result in heterogeneous gas content distribution. Gas content decreases with decreasing pressure and temperature, and coal beds become undersaturated with respect to methane during basin uplift and cooling. Gas content generally increases where conventional and hydrodynamic trapping of coal gases occur and may decrease in areas of active recharge with downward flow potential and/or convergent flow where there is no mechanism for entrapment.

Keywords: Hydrogeologic factors; Gas content distribution; Coal beds

1. Introduction

Coalbed methane exploration continues in many countries worldwide, although the rate of coalbed methane resource development appears to be highly variable due to local economic factors and government energy priorities and policies. However, many countries may eventually see a significant growth rate in coalbed methane production similar to that in United States, although the total annual coalbed methane production may be lower.

Coalbed methane is an important part of the natural gas supply for the United States and now represents more than 7% of total dry gas production and 9% of proved dry gas reserves (Energy Information Administration, 2001). Although initial coal gas exploration and development were performed initially by major oil companies and larger independents, smaller operators have played a progressively more important role in developing this natural resource. Coal gas resources for the contiguous United States are estimated to be

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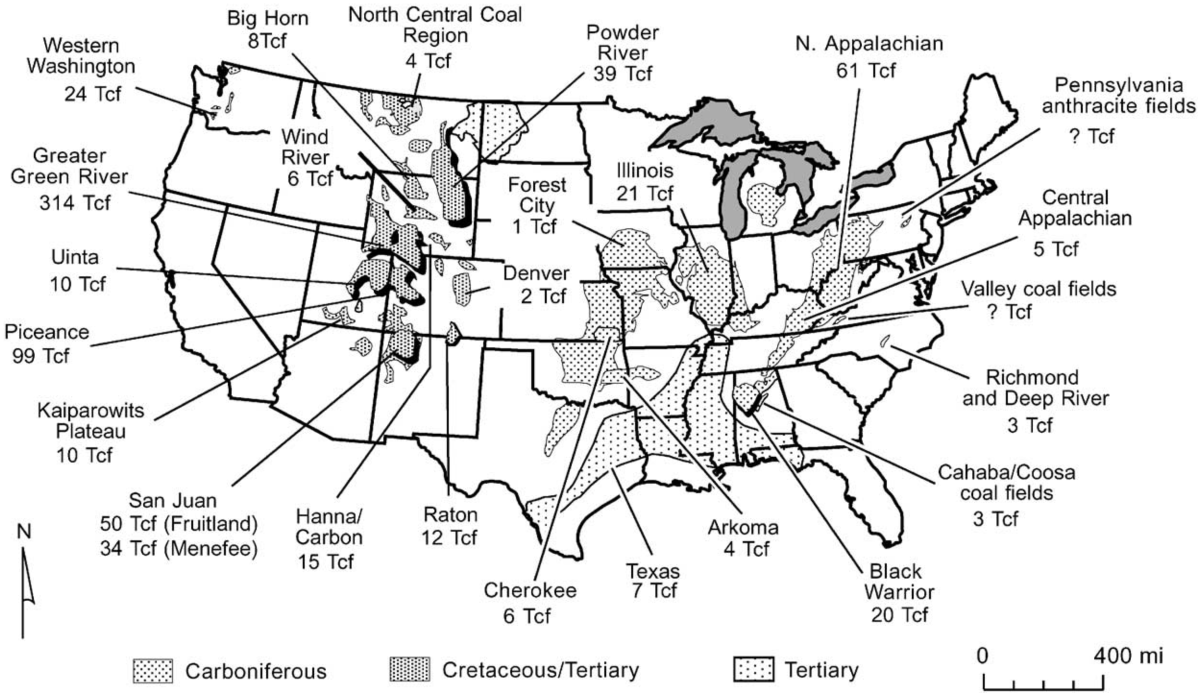


Fig. 1. Coalbed methane resources of the United States are estimated to be 755 Tcf (21.4 Gm^3) Alaska contains an estimated 1037 Tcf (29.4 Tm^3). Data modified from GTI E&P Services (2001).

more than 755 Tcf (21.38 Tm^3) and more than 80% is located in the western United States (Fig. 1). Coalbed methane resources in Alaska probably exceed 1037 Tcf (29.36 Tm^3) (Clough et al., 2001).

Annual coal gas production has increased two orders of magnitude from less than 10 Gcf (0.28 Gm^3) in 1985 to more than 1.379 Tcf (39.04 Gm^3) in 2000 (Fig. 2). Although over 80% of current coal gas

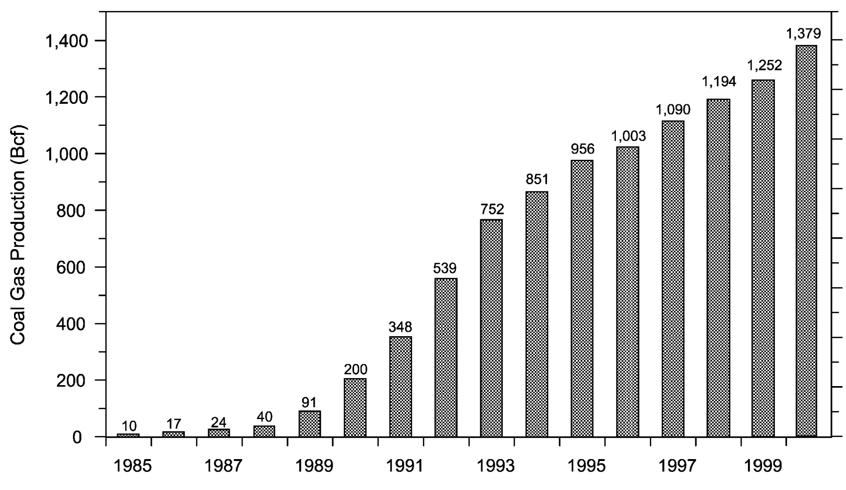


Fig. 2. Coalbed methane production in the United States. Coalbed methane production in the United States has risen from 10 Bcf (0.28 Gm^3) in 1985 to more than 1379 Gcf (39.04 Gm^3) in 2000. Data from Energy Information Administration (2001).

production is derived from the San Juan Basin, coal gas production from other western basins continues to increase, particularly from the Powder River Basin. Coal gas proved reserves remained relatively constant, increasing slightly over the past 4 years, and are currently estimated to be approximately 13.23 Tcf (375 Gm^3) (Energy Information Administration, 2001). The increase in proved coal gas reserves despite the significant increase in production is attributed to the efforts of smaller operators and independents in finding new reserves. Coal gas production and reserves are expected to increase as exploration continues in unexplored areas and as secondary recovery techniques using nitrogen or carbon dioxide are employed.

Understanding the geologic and hydrologic factors that control the amount of gas sorbed on coals is critical to developing an effective and successful exploration program. Therefore, a review of the key hydrogeologic factors that affect coalbed methane producibility and a detailed discussion of how these hydrogeologic factors ultimately determine the gas content of a coal is warranted. This model is based on a decade of coalbed methane research in the United States and can be used to predict areas of unusually high gas content values and, of equal importance to the explorationist, areas of unusually low gas content values.

2. Coalbed exploration model

Coalbed methane exploration strategies are often based only on the location of the greatest net coal thickness and ignore other hydrologic and geologic factors affecting coalbed methane producibility. Coalbed methane producibility is determined by the complex interplay among six critical controls: depositional systems and coal distribution, tectonic and structural setting, coal rank and gas generation, gas content, permeability, and hydrodynamics (Figs. 3 and 4) (Kaiser et al., 1994; Scott, 1999). If one or more of these key hydrogeologic factors is missing, then the potential for higher coalbed methane producibility will be reduced. However, the coalbed methane play may remain economically viable. For example, the Piceance Basin is characterized by exceptionally high gas content values (more than 700 scf/ton; 21.8 cm^3/g), but coalbed methane production has been limited because of low permeability. However, the Powder River Basin remains economically successful with gas content generally less than 20 scf/ton (0.6 cm^3/g), because thick (more than 100 ft; 30 m) coal beds are present at shallow depths. A review of each hydrogeologic factor will be followed by examples from the San Juan and Greater Green River Basin.

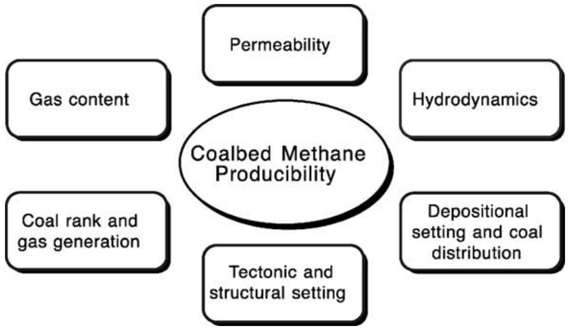


Fig. 3. An integrated coalbed methane exploration model considers the geologic and hydrologic controls critical to coal gas producibility as well as engineering practices and economic considerations. Modified slightly from Kaiser et al. (1994).

2.1. Depositional setting and coal distribution

Coal beds are the source and reservoir for methane, indicating that their widespread distribution within a basin is critical to establishing a significant coalbed methane resource. Coal distribution is closely tied to the tectonic, structural, and depositional settings (Fig. 4a), because peat accumulation and preservation as coal require a delicately balanced subsidence rate that maintains optimum water-table levels but excludes disruptive clastic sediment influx. The depositional systems define the substrate upon which peat growth is initiated and within which the peat swamps proliferate. Net coal thickness trends and depositional fabric strongly influence migration pathways and the distribution of gas content. The depositional setting also controls the types of organic matter (macerals) which affect sorption characteristics and the quantity of hydrocarbons produced from the coal. Knowledge of depositional framework enables predication of coalbed thickness, geometry, and continuity and, therefore, which potential coalbed methane resources (Ayers et al., 1991; Pashin, 1994).

(a)

DEPOSITIONAL SETTING AND COAL DISTRIBUTION	
Tectonic setting	Regionally affects geometry, occurrence, and thickness of coal beds
Hydrodynamics	Recharge and ground-water flow influenced by coal continuity and geometry
Permeability	Local permeability enhancement associated with compaction over sandstones
Gas content	Maceral composition affects gas sorption and desorption rates
Coal rank and gas generation	Maceral type affects hydrocarbon generation rates and types of hydrocarbons

(b)

TECTONIC AND STRUCTURAL SETTING	
Depositional setting	Regionally controls orientation, geometry, and occurrence of facies and coal beds
Coal rank and gas generation	Burial history, coalification, gas generation, and timing of cleat development
Gas content	Uplift and cooling produces undersaturation and possible degassing of coals
Permeability	Decreases with depth; cleat orientation; present-day in-situ stress; anticlines
Hydrodynamics	Hydrologic control on peat accumulation; uplift of basin margins for recharge; isolation of coals from outcrop

(c)

COAL RANK AND GAS GENERATION	
Gas content	Thermogenic gas generation may result in higher gas contents
Depositional setting	The presence of thick, thermally mature coals enhances coalbed methane producibility
Tectonic setting	Burial history controls coalification and thermogenic gas generation
Hydrodynamics	Wet gases and condensate converted into secondary biogenic methane by bacteria
Permeability	Cleat frequency and, therefore, permeability increase with increasing rank

(d)

GAS CONTENT	
Coal rank and gas generation	Generally increases with coal rank and depth; updip migration; diffusion coefficients
Depositional setting	Macerals affect gas sorption and desorption; shale seals; coal thickness and continuity
Tectonic setting	Conventional trapping of gases at faults and anticlines; burial history; diagenesis
Hydrodynamics	Secondary biogenic methane; high or low gas content at convergent flow; low gas content possible near recharge zone
Permeability	High permeability near recharge zone may allow flushing and low gas content

(e)

PERMEABILITY	
Hydrodynamics	Meteoric recharge and enhanced near outcrop; diagenesis in sands; low/high permeability detrimental
Tectonic setting	Decreases with depth; present-day in-situ stresses; enhancement with structures; fault barriers
Depositional setting	Enhancement through compaction; sands as barriers; coal pinch-out; macerals and cleats
Coal rank and gas generation	Cleat frequency increases with rank; annealing; cleats filled with bitumen and minerals
Gas content	High permeability and flushing; high gas content and moderate permeability

(f)

HYDRODYNAMICS	
Tectonic setting	Uplifted margins; faults as flow barriers; flow enhancement along structures; isolation of outcrop coals; in-situ stresses; cross flow
Depositional setting	Permeability contrasts associated with facies; coal aquifer continuity; macerals and cleats
Coal rank and gas generation	Ground-water flow through higher rank coals; updip migration thermogenic gases
Gas content	High with convergent flow and permeability barriers;
Permeability	Water production implies permeability; high and low permeability detrimental; bacteria

Fig. 4. Understanding the synergistic interplay among the key geologic and hydrologic factors affecting coalbed methane producibility is critical for evaluating coalbed methane potential. (a) Depositional setting and coal distribution, (b) tectonic and structural setting, (c) coal rank and gas generation, (d) gas content variability, (e) permeability, and (f) hydrodynamics that includes meteoric recharge and the subsurface migration of fluids.

2.2. Tectonic and structural setting

The tectonic and structural setting control of a basin control the distribution and geometry of coal beds in the basin during deposition, and therefore, exert a strong control on the lateral variability of macerals (Fig. 4b). Both the burial history and stress direction control the timing of cleat development in various parts of the basin and the final orientation of face cleats. The basin burial history and variability of regional heat flow control coalification and the types and quantities of thermogenic gases generated from the coals. Additionally, present-day in situ stress directions may significantly affect coalbed methane producibility. Stress directions orthogonal to face cleats will lower permeability, whereas stress directions parallel to face cleat orientation may enhance permeability. Uplift and basinal cooling often result in undersaturation with respect to methane in the coals and possible degassing of coal beds. Finally, the location and geometry of folds and faults may strongly influence the recharge of meteoric water, and therefore, the generation of biogenic gases.

2.3. Coal rank and gas generation

Coals must reach a certain threshold of thermal maturity (vitrinite reflectance values between 0.8% and 1.0%; high-volatile A bituminous) before large volumes of thermogenic gases are generated. The amount and types of coal gases generated during coalification are a function of burial history, geothermal gradient, maceral composition, and coal distribution within the thermally mature parts of a basin (Fig. 4c). Gases in coal beds may also be formed through the process of secondary biogenic gas generation. Secondary biogenic gases are generated through the metabolic activity of bacteria, introduced by meteoric waters moving through permeable coal beds or other organic-rich rocks. Thus, secondary biogenic gases differ from primary biogenic gases because the bacteria are introduced into the coal beds after burial, coalification, and subsequent uplift, exposure, and erosion of basin margins. The bacteria metabolize wet gas components, *n*-alkanes, and other organic compounds at relatively low temperatures (generally less than 150 °F, 56 °C) to generate methane and carbon dioxide. Secondary biogenic gases are known to occur in subbituminous through low-volatile bituminous and higher-rank coals (Scott, 1993, 1994).

2.4. Gas content

Gas content is one of the most important controls of coalbed methane producibility, yet often is one of the more difficult parameters to accurately assess. Gas content is not fixed, but changes when equilibrium conditions within the reservoir are disrupted and is strongly dependent upon multiple hydrogeologic factors and reservoir conditions (Scott and Kaiser, 1996) (Figs. 4d and 5). The distribution of gas content varies laterally within individual coal beds, vertically among coals within a single well, and laterally and vertically within thicker coal beds (Fig. 6). In general, gas content increases with depth and coal rank, but is often highly variable due to geological heterogeneities, the type of samples taken, and/or the analytical laboratory. The gas content of coal can be enhanced, either locally or regionally, by generation of secondary biogenic gases or by diffusion and long-distance migration of thermogenic and secondary biogenic gases to no-flow boundaries such as structural hingelines or faults for eventual resorption and conventional trapping. Therefore, determination of migration direction through isotopic and hydrogeologic studies is critical for determining migration direction and the areas of higher gas content.

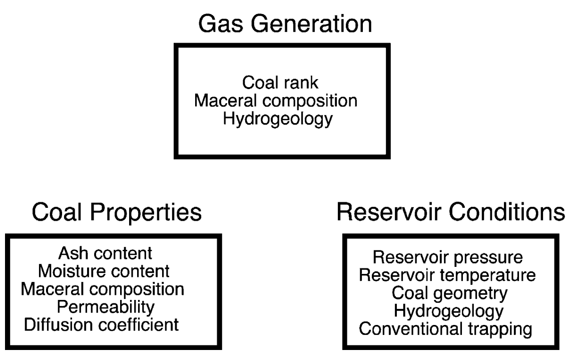


Fig. 5. Hydrogeologic factors affecting the generation, retention, migration and accumulation of thermogenic and secondary biogenic gases in coal beds. Gas content distribution is one of the key factors affecting the economics of coalbed methane exploration and development. Modified slightly from Scott and Kaiser (1996).

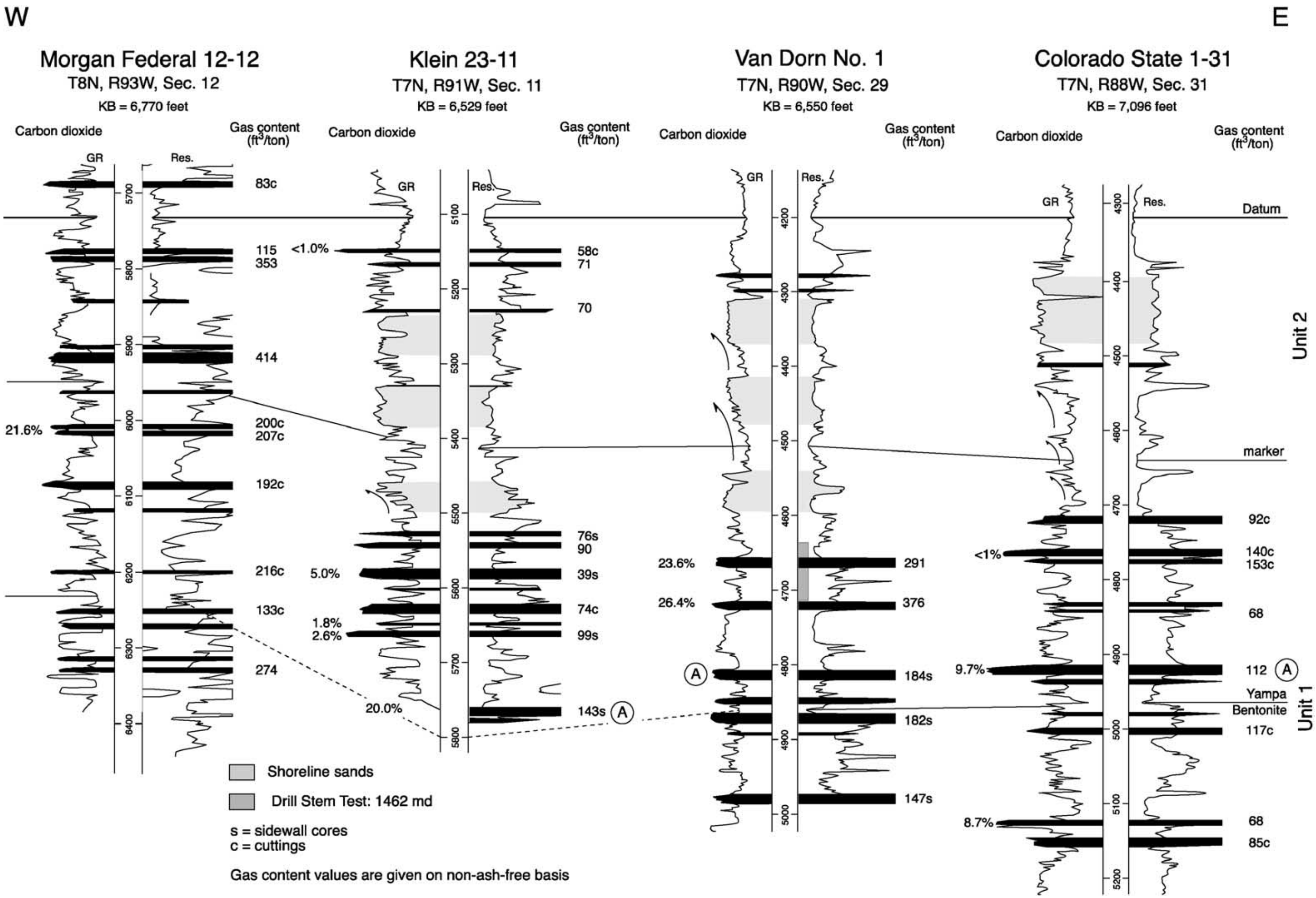


Fig. 6. Cross-section from the Sand Wash Basin, CO, USA shows the lateral and vertical heterogeneity of gas content values in coal beds. The high gas contents in the upper coal seams in the Morgan Federal 12–12 well may be due to stratigraphic and structural trapping of gases during updip migration. Modified from Scott (1994).

2.5. Permeability

Permeability in coal beds is determined by its fracture (cleat) system, which is in turn largely controlled by the tectonic/structural regime as mentioned previously (Fig. 4e). Cleats and fractures are the permeability pathways for migration of gas and water to the producing well head, and cleats may either enhance or retard the success of the coalbed methane completion. Permeability will decrease with increasing depth, suggesting that in the absence of structurally enhanced permeability at depth, coalbed methane production may be limited to depths less than 5000 to 6000 ft (1524 to 1829 m). Permeability is highly variable in coal beds ranging from darcies to microdarcies, but the most highly productive wells have permeability ranging between 0.5 and 100 md (Fig. 7). Precipitation of authigenic minerals in cleats during diagenesis may significantly reduce permeability and have a significant impact on regional (and local) fluid migration directions. Higher permeability will result in recovery of more sorbed coal gases, because lower reservoir pressures and, therefore, more coal gas desorption will occur in higher permeability reservoirs. However, permeability that is too high results in high water production and may be as detrimental to the economic production of coalbed gas as extremely low permeability.

2.6. Hydrodynamics

Hydrodynamics strongly affect coalbed methane producibility and includes both the movement of meteoric water basinward as well as the migration of fluids from deeper in the basin. Basinward migration of ground water is intimately related to coal distribution and depositional and tectonic/structural setting because ground water movement through coal beds requires recharge of laterally continuous permeable coals at the structurally defined basin margins (Fig. 4f). Coal beds act not only as conduits for gas migration but also are commonly ground-water aquifers having permeabilities that are orders of magnitude larger than associated sandstones. The presence of appreciable secondary biogenic gas indicates an active dynamic flow system with overall permeability sufficient for high productivity. Migration of thermogenic may result in abnormally high gas contents in lower rank coals or coals that are saturated or oversaturated with respect to methane.

Basin hydrogeology, reservoir heterogeneity, location of permeability barriers (no-flow boundaries), and

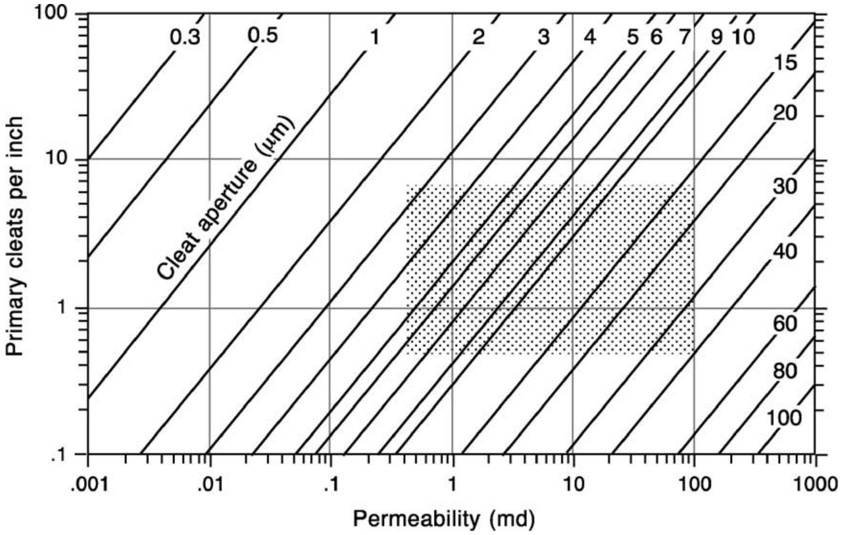


Fig. 7. Relationship between cleat spacing, permeability and aperture size. Coal seams are similar to fractured carbonate reservoirs, because permeability is restricted to fractures (or cleats) separated by an impermeable matrix. This graph represents an approximation of average aperture size (diagonal lines) but actual in situ aperture sizes will probably be larger and smaller than indicated from the graph. Graph is based on a cubic law equation described by Lucia (1983) and is modified slightly from Scott (1995).

the timing of biogenic gas generation and trap development are critical for exploration and development of unconventional gas resources in organic-rich rocks.

3. Hydrogeologic factors affecting gas content distribution

Gas content is one of the more important controls on coalbed methane producibility because coalbed methane production becomes uneconomical if insufficient amounts of gas are sorbed onto the coal surface. As mentioned previously, exceptionally high gas contents do not necessarily guarantee high production rates if permeability is too low. A major problem in evaluating gas content trends is the accuracy of the data that are affected by analytical method, sample type, and gas composition used on during the experiments. Assuming that gas content data reported are reasonably accurate, there are many geologic and hydrologic factors that affect the distribution of coal gas in the subsurface (Fig. 1) and these factors can be divided into three categories: (1) gas generation, (2) coal properties, and (3) reservoir conditions. Each of these factors will be discussed in greater detail below.

4. Gas generation

Coal gases are generated through thermogenic and biogenic processes. The presence of abnormally high gas contents in coals that have not reached the thermal maturity required to generate significant methane is an indicator of secondary biogenic gas generation and/or migration of gases (Scott and Ambrose, 1992). Additionally, the presence of coals saturated with respect to methane also suggests that the generation of secondary biogenic methane and/or the migration thermogenic and biogenic gases may have occurred. Therefore, understanding coal gas origins and delineating migration pathways is important for coalbed methane exploration and development.

4.1. Coal rank

A certain threshold of thermal maturity is required for significant thermogenic gas generation and gas content at coal ranks below this threshold are generally low (less than 100 scf/ton; 3.1 cm^3/g). Lower-rank coals are often found around basin margins due to shallow burial depths and coal gases associated with these coals are often secondary biogenic gases. Most operators in the United States believe that coals must usually contain a minimum of 200 to 300 scf/ton (6.3 to 9.4 cm^3/g) for economic production of coal gas. A study by Tang et al. (1991) suggested that an economic threshold of 300 scf/ton (9.4 cm^3/g) is not attained until the high-volatile A bituminous rank at vitrinite reflectance values between 0.8% and 1.0% (Fig. 8). This is one of the reasons why higher gas content values are commonly associated with higher rank coals, although it must be stressed that not all high rank coals have high gas contents. For example,

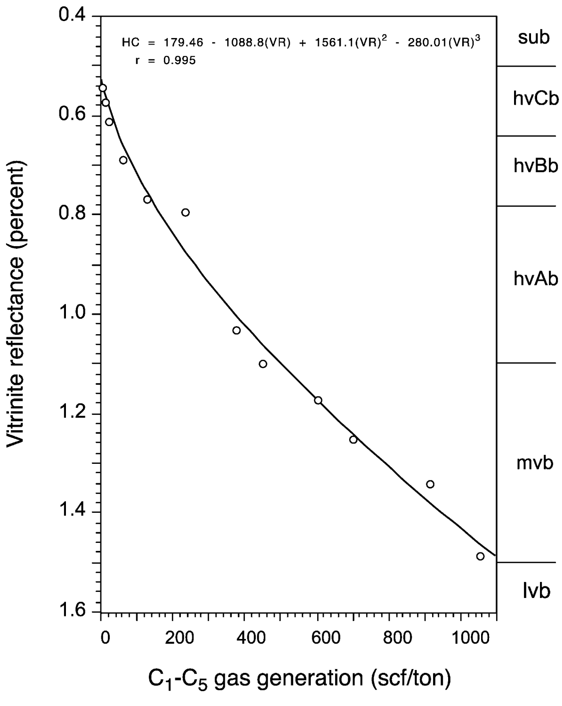


Fig. 8. Gas content generally increases with increasing thermal maturity (coal rank), but significant thermogenic methane generation does not occur until the high-volatile A bituminous rank is reached at vitrinite reflectance values between 0.8% and 1.0%. However, at least some early thermogenic gas generation may occur at vitrinite reflectance values of 0.40%. sub = subbituminous; hvCb = high-volatile C bituminous; hvBb = high-volatile B bituminous; hvAb = high-volatile C bituminous; mvb = medium volatile bituminous; lvb = low-volatile bituminous. Data from Tang et al. (1991).

gas contents in the Piceance Basin show an overall increase in gas content with increasing rank (Fig. 9a). However, gas content profiles in the San Juan Basin indicate that lower rank coals actually have higher gas contents than higher rank coals (Fig. 9b). In other basins, coal rank has little influence in gas content profiles (Fig. 9c and d) and other factors must be considered in explaining gas content distributions.

One of the more important criteria for evaluating a coalbed methane basin is determining if there are higher-rank gassy coals at acceptable (economic) drilling depths. Basins with the highest coalbed methane production in the United States all have high volatile A bituminous coals at depths less than 4000 ft (1200 m). Peak gas generation occurs during the medium- to low-volatile bituminous ranks, indicating that areas in a basin containing coals of these ranks should be considered as potential exploration targets. Comparison of vitrinite reflectance profiles between basins or from areas within individual basins can provide valuable information about the depths at which economic gas generation has occurred and where higher gas contents are possible. In the absence of sufficient subsurface vitrinite reflectance data, surface vitrinite reflectance trends may indicate the distribution of higher-rank coals at relatively shallow depths.

Coal rank also has an important effect on the sorptive behavior and storage capacity of coal. The adsorptive capacity of coal is traditionally described as increasing with coal rank (Kim, 1977). However, methane sorption capacity actually decreases with increasing rank until the high-volatile A bituminous rank (85% fixed carbon or R_m of approximately 0.80%) is reached and subsequently increases with progressive coalification (Moffat and Weale, 1955; Thomas and Damberger, 1976; Patching, 1970; Schwarzer, 1983). The generation of n-alkanes, waxes, and other hydrocarbons during the oil-generating stage in hydrogen-rich coals reduces the accessibility of methane to the coal structure by plugging micropores (Levine, 1993). With increasing coalification, thermal cracking of these compounds not only generates thermogenic methane but increases methane adsorptive capacity by unplugging pores, resulting in improved methane accessibility to the micropore network. Progressively more methane is generated, and the coal structure is modified to accept additional thermogenic methane, resulting in higher sorption capacity and gas content values.

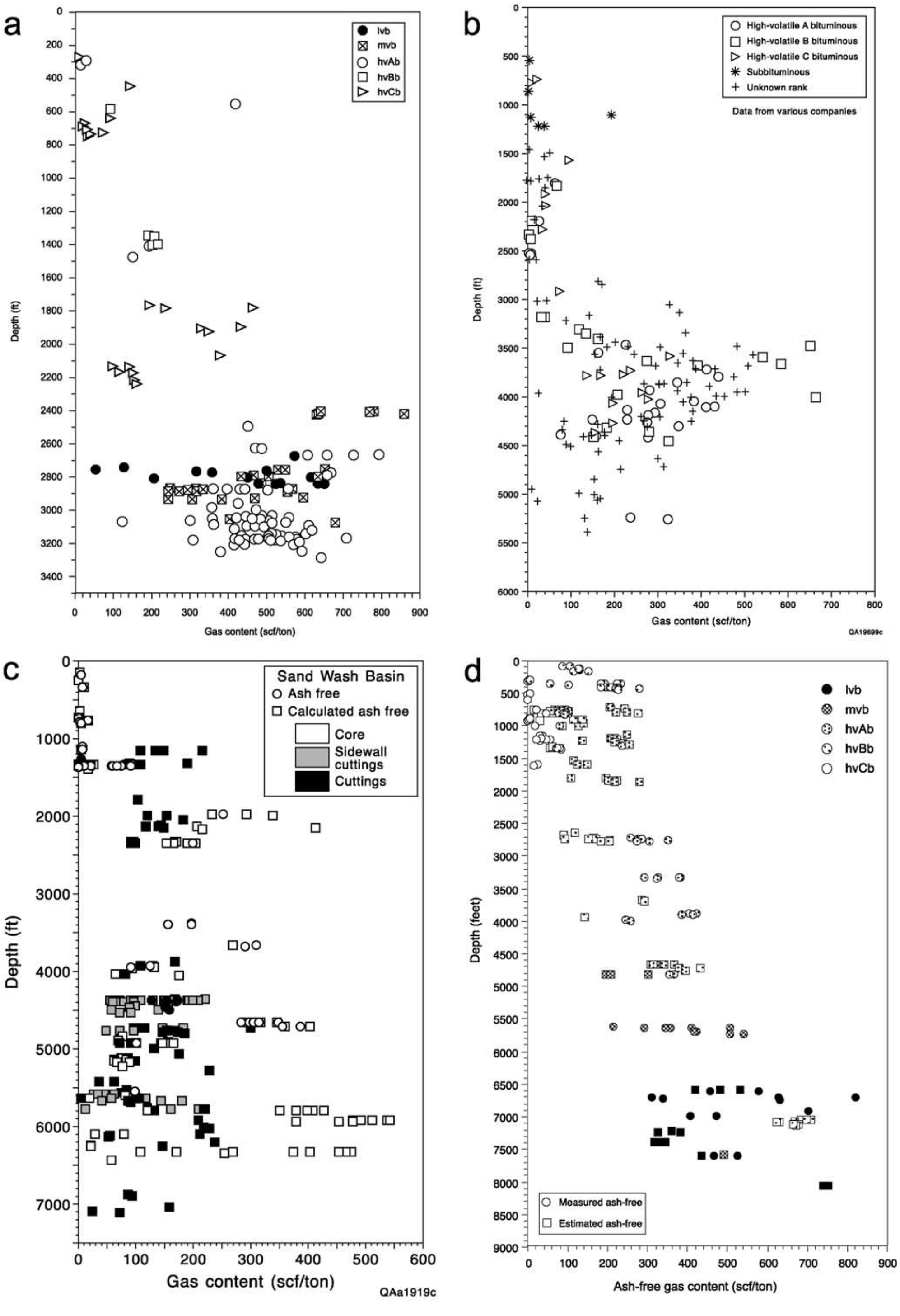
4.2. Maceral composition

The methane generation potential is directly related to the maceral composition; coals with even minor quantities of hydrogen-rich components are capable of generating more methane (Fig. 10). For example, based on the data of Levine (1992), a coal composed entirely of vitrinite is capable of generating 4700 scf/ton (147 cm^3/g) over the vitrinite reflectance range of 0.5% to 2.0%. A coal composed of 90% vitrinite and 10% sporinite will generate nearly 5900 scf/ton (183 cm^3/g) over the same vitrinite reflectance range. However, these estimates are based on the assumption that only methane and carbon dioxide are released during coalification, whereas coals often generate liquid hydrocarbons. Therefore, the quantity of methane generated from coals may be lower that these estimates, particularly if the wet gases and liquid hydrocarbon migrate out of the system. Finally, inertinite-rich coals will not generate large quantities of methane because inertinite has relatively little hydrocarbon generating potential. Therefore, the distribution of inertinite-rich coals may have to be considered when developing coal gas resources.

4.3. Hydrogeology

Hydrogeology affects gas content through the generation of secondary biogenic gases that increase the gas available for sorption, the development of regional overpressure that allows more gas (if available for sorption) to be stored on the coal, the migration of thermogenic and biogenic gases to permeability barriers that locally increases gas content, and the potential removal of gases (lowering of gas content) by water moving through permeable coal beds. Therefore, understanding the hydrogeology (fluid migration directions) of a system can be very important for predicting gas content distribution, particularly in lower-rank coals that are below the threshold of thermogenic gas generation.

Lower-rank coals are often located along basin margins where minimum subsidence and burial temperatures have occurred. These shallow coals often have higher permeability due to reduced overburden,


a
lvb
mvb
hvAb
hvBb
hvCb
Depth (ft)
Gas content (scf/ton)
b
High-volatile A bituminous
High-volatile B bituminous
High-volatile C bituminous
Subbituminous
Unknown rank
Data from various companies
Depth (ft)
Gas content (scf/ton)
QA19699c
c
Sand Wash Basin
Ash free
Calculated ash free
Core
Sidewall cuttings
Cuttings
Depth (ft)
Gas content (scf/ton)
QAa1919c
d
lvb
mvb
hvAb
hvBb
hvCb
Measured ash-free
Estimated ash-free
Depth (feet)
Ash-free gas content (scf/ton)

indicating that the coals are capable of accept meteoric recharge. Bacteria introduced into the coal beds can metabolize wet gases, *n*-alkanes, and organic compounds generated during coalification to produce secondary biogenic gases. The importance of secondary biogenic gases in coalbed methane producibility was first recognized in the San Juan Basin (Scott et al., 1991, 1994; Kaiser et al., 1991). Secondary biogenic gases were subsequently recognized in other basins in the United States (Tyler et al., 1991) and throughout the world (Rice, 1993). The generation of secondary biogenic gases increases gas contents beyond that expected from coal rank and if generated in sufficient quantities can actually resaturate the coal to the sorption isotherm (Scott et al., 1994) (Fig. 11). Based on cumulative production figure through 1998, approximately 1.5 to 2 trillion ft^3 (42.5 to 56.6 Gm^3) of secondary biogenic methane have been produced from the San Juan Basin.

In addition to generating secondary biogenic gases, artesian overpressure associated with meteoric recharge can potentially increase gas content by increasing reservoir pressure and allowing more gas to be sorbed on the coal. The increase in reservoir pressure will allow secondary biogenic gases (generated in situ) and/or migrating thermogenic and biogenic gases to become sorbed onto the coal. An increase in reservoir pressure alone is not enough to increase gas content; an outside source of the gas is required as well. Gas content values in part of the Sand Wash Basin are significantly higher than the overall gas content trends for the rest of the basin (Fig. 9b). The gas content of high-volatile A bituminous coals (R_m of 0.8 to 0.9%) in the northern, overpressured part of the San Juan Basin exceed 500 scf/ton (15.6 cm^3/g), which is higher than gas contents of similar rank coals in other U.S. basins.

Meteoric water moving though permeable coal beds may also have an adverse effect on gas contents. Diffusion of gases in coal beds is controlled by diffusion gradients rather than pressure. In a static hydrologic system, there is probably an equilibrium between the amount of gas sorbed on the coal and dissolved gas in the cleat system. However, when these equilibrium conditions are disrupted in an active ground water system, diffusion from of the coal matrix into the cleat system may occur, thus lowering gas content. The diffusion rate through the coal matrix may increase when concentration gradients increase as dissolved methane is transported away through the cleat system. Coals with high diffusion coefficients would probably lose gas more rapidly and gas contents could be significantly lowered unless the gas is replenished through in situ secondary biogenic gas generation and/or migration of thermogenic and biogenic gases into the coal beds.

5. Coal properties

Coal properties, such as ash content, in situ moisture content, maceral type, permeability, and diffusivity, are an important component affecting the sorption, desorption and, therefore, total gas content in coal beds. The monolayer capacity (or Langmuir volume) is the point at which the coal is completely saturated with gas and the microporous coal surface area is covered with one layer of gas molecules. In some cases, the methane molecules are so closely packed on the coal surface that the density of gas molecules approaches that of liquid methane (Creedy, 1988). Therefore, coal characteristics affecting the sorption capacity of the coal are also important for methane sorption and the retention of methane over time.

5.1. Mineral matter (ash) content

Nearly all of the gas in coal beds is adsorbed onto coal surfaces rather than ash layers or dispersed mineral matter in coal beds. Gas stored in carbonaceous shales associated with coal beds is sorbed to the organic fraction of the shales rather than the inorganic fraction, or minerals. In order to compare

Fig. 9. Gas content profiles for four basins in the United States often show large variability with depth and rank. (a) San Juan Basin, (b) northeastern Rock Springs Uplift, in Greater Green River Basin, (c) Sand Wash subbasin of the Greater Green River Basin, (d) Piceance Basin. The presence of abnormally high gas contents in lower rank coals indicates secondary biogenic gas generation and/or migration of coal gases. The good correlation of gas content with depth in the Piceance Basin is due to generally low permeability and limited meteoric recharge; meteoric recharge significantly impacts gas content distribution in coal seams.

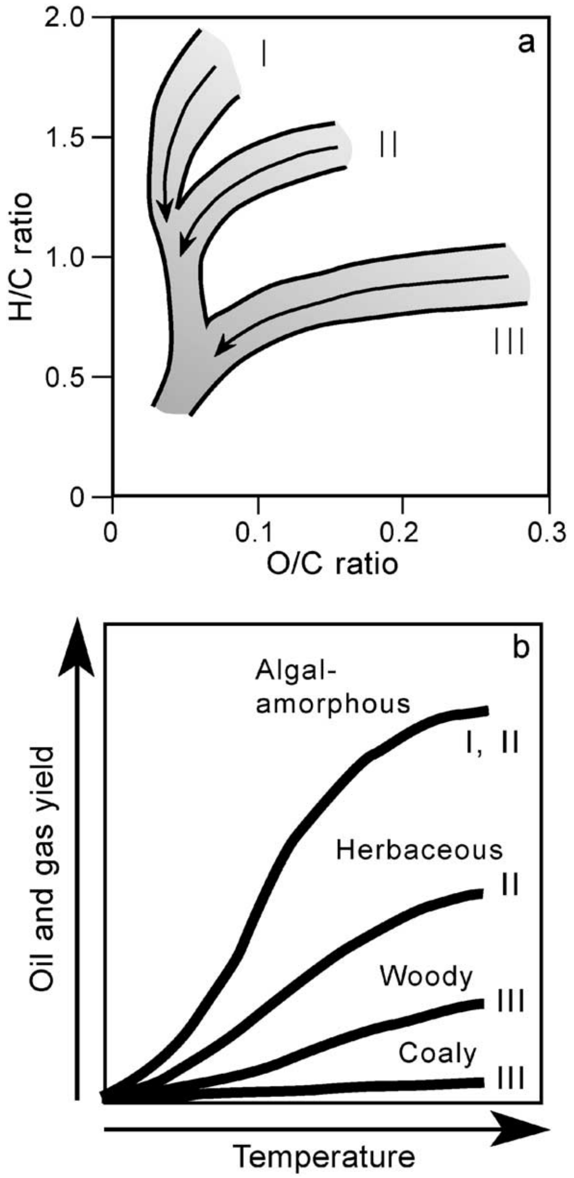


Fig. 10. Thermogenic coal gas generation depends on maceral composition as well as thermal maturation trends. (a) Most coals fall between Types II and III on a van Krevelen diagram, (b) hydrogen-rich coal macerals have a very large gas generating potential relative to other maceral types. From Hunt (1979).

gas content measurements among various coal samples and to determine gas content trends within or among basins, it is important that the sorption isotherms and gas content measurements be corrected to an ash-free basis. Gas content values and sorption isotherms should be reported on an ash-free basis to eliminate the effects of mineral matter (ash) variability among coal beds. For example, a coal seam comprised of 50% ash and a gas content value of 300 sct/ton (9.4 g/cm^3) contains much more gas sorbed to the organic fraction (600 scf/ton ash-free; 18.7 g/cm^3) than an ash-free coal containing 400 scf/ton (12.5 g/cm^3). In-place coal gas resource estimates must take into consideration whether or not the gas content is corrected to an ash-free basis (Scott et al., 1995).

5.2. Moisture content

Adherent (mechanically retained) and inherent (physically sorbed) moisture contents are more important to coalbed methane than the other types and the following discussion of "moisture" will be restricted to those two types. Moisture content decreases with increasing coal rank (Fig. 12) and most of the water is lost before coal reaches the high volatile A bituminous rank. The effect of moisture on the sorptive capacity of coal has been known for some time. Sorption capacity can decrease significantly with increasing moisture content and attempts to correct for moisture have been made.

Joubert et al. (1973, 1974) demonstrated the importance of moisture content on the sorptive capacity of coals (Fig. 13) and determined that moisture content is related to the oxygen content of the coal. A good correlation exists between as-received moisture and oxygen content over a wide range of coal rank, suggesting that there may be a strong interaction between the adsorbed water molecules and the oxygen compounds on the coal surface. However, coal surface and water interactions are complex and coal porosity may also be important in water sorption (Mahajan, 1989). There is an upper limit of moisture content for each coal beyond which additional moisture has no effect on the sorptive capacity of coal. Because moisture can significantly affect the sorption capacity of the coal, it is important to run the sorption isotherms near the in situ moisture content of the coal. Unfortunately, proximate and ultimate analyses are not always performed on coal samples which makes correcting gas content data to a dry, ash-free basis impossible and the detailed evaluation of gas content trends difficult.

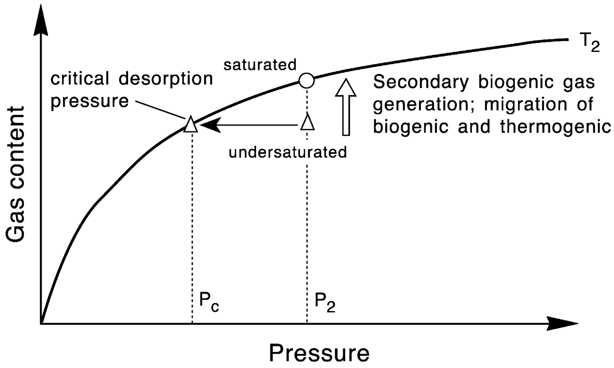


Fig. 11. The sorption of secondary biogenic gases generated in situ and/or migration of thermogenic and biogenic gases can locally increase gas content and saturate to oversaturate the coals with respect to methane. From Scott et al. (1994).

5.3. Maceral type and gas sorption capacity

There have been relatively few studies on the relative sorptive capacities of individual macerals although the new microgravimetric or gravimetric approach which was developed independently in Australia (Beamish et al., 1991; Beamish and O'Donnell, 1992) and the U.S. (Levine, 1993) will probably allow detailed sorption studies to be carried out. Ettinger et al. (1966) suggested that coals composed predominantly of inertinite (fusain) are capable of holding less methane than vitrinite-rich coals. Levine et al. (1993), using a microgravimetric approach to evaluate individual maceral types, show a distinct variability in sorption capacity with maceral type (Fig. 14). Recent work by Lamberson and Bustin (1993) on western Canadian coals also indicates that coals with the lowest methane sorption capacity are inertinite-rich, whereas vitrinite-rich coals have the highest sorption capacity. The relative sorptive capacity of exinite-rich coals is uncertain but may be less than that of vitrinite-rich coals.

The rate at which methane is sorbed and desorbed from coal varies with the maceral type. Beamish et al.

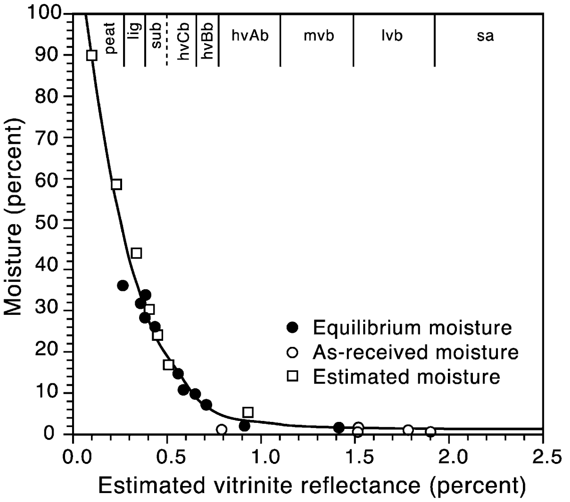


Fig. 12. Changes in moisture content with increasing coal rank. Over 75% of the moisture loss during coalification occurs before the high-volatile bituminous ranks are reached. sub = Subbituminous; hvCb = high-volatile C bituminous; hvBb = high-volatile B bituminous; hvAb = high-volatile C bituminous; mvb = medium volatile bituminous; lvb = low-volatile bituminous.

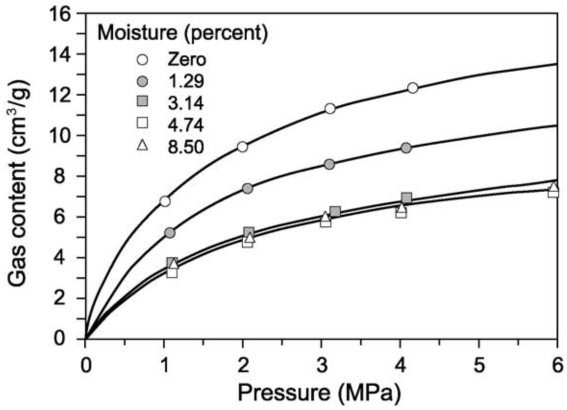


Fig. 13. Variation of sorption capacity with moisture content. Gas sorption capacity decreases significantly with increasing moisture content until an upper limit of moisture content is reached. At this point, additional moisture has no effect on sorption capacity. From Joubert et al. (1974).

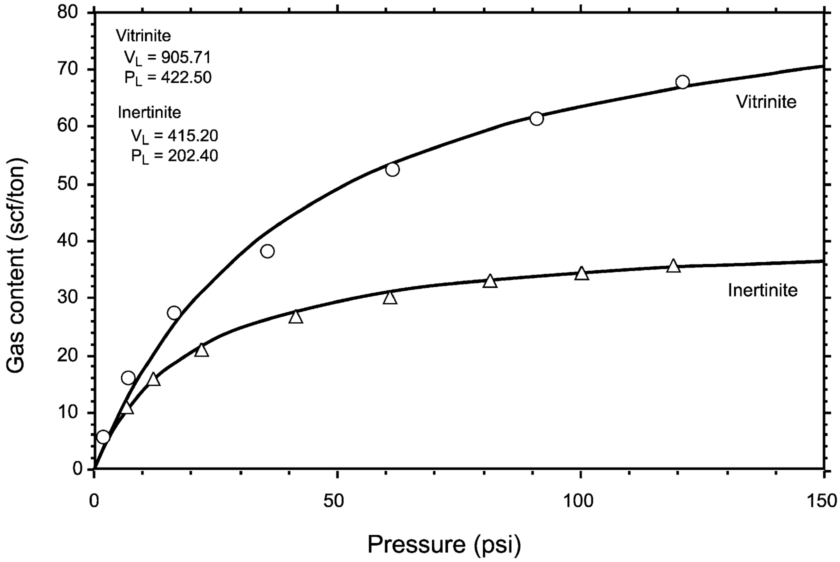


Fig. 14. Changes in sorption capacity for different macerals. Vitrinite has greater sorption capacity than inertinite. Additionally, inertinite desorbs methane at a much faster rate than that of other macerals. Data from Levine et al. (1993).

(1993) suggest that bright coals composed nearly entirely of vitrinite-group macerals (telocollinite) desorb more slowly than intertinite-rich coals. The structure of inertinite-rich (dull) coals is also important to desorption rate. Beamish et al. (1993) determined that rapid desorption in dull coals was related to open, unmineralized bands of wood fibers, whereas relatively slow desorption may be a function of fewer macropores and a higher proportion of micropores. Therefore, the coal structure on a microscopic scale is also important to the sorption/desorption process. Gamson et al. (1993) have also indicated that microstructure density, continuity, orientation, and the amount of void infilling and type of microstructures all affect gas drainage in coal beds. Ettinger et al. (1966) suggested that inertinite-rich coals may be more prone to blowouts that inertinite-poor seams because of the rapid desorption of methane and carbon dioxide from inertinite-rich coals. Gas desorption in vitrinite-rich coals occurs more rapidly with increasing coal rank possibly because of increased microfracturing in vitrain bands (Beamish et al., 1993).

Although maceral composition probably does affect coal sorption capacity, gas production occurs from a large volume of coal. Therefore, variability of relative gas sorption rates among macerals is probably averaged out during production and can be accounted for through adequate sampling procedures. However, variability in desorption rates and total methane recovery may become more pronounced if the coals are dominated by one maceral type. If maceral composition can be related to the depositional system, then a knowledge of the coal geometry and depositional trends may prove useful in predicting areas with favorable gas contents.

5.4. Permeability, diffusivity, and gas migration

The physical structure of coal can be characterized by micropore and macropore components. The micropores probably range in size from 0.5 to 1.0 nm in diameter and are part of the organic coal matrix. The macropores are represented by naturally occurring fractures or cleats in the coal and include microfractures. Gas movement in coal beds is migration through microfractures and cleats and by diffusion through the coal matrix. Gas molecules diffuse through the coal matrix in response to concentration gradients, whereas the gas molecules obey Darcy's Law once they reach the cleat system and migrate in response to pressure gradients. Gas migration through the cleat system occurs at a much greater rate than diffusion though the coal matrix indicating that a well-developed cleat system is critical to successful coalbed methane producibility. Gamson et al. (1993) have suggested that the two-step flow may be simplified and that gas migration in coal beds may actually be a four-step process. The first step is diffusion from and through the micropores of the coal to microfractures and cavities. According to Gamson et al. (1993), the second step is diffusional/migrational flow of gases through microfractures and cavities that are partially occluded by diagenetic minerals, whereas the third step is migration through unmineralized microfractures and cavities having aperture widths of 0.05 to 20 μm. The final step of the migration process is presumably through larger cleats.

Although cleat widths (aperture size) can be easily measured in the outcrop, direct measurement of cleat aperture sizes in the subsurface is difficult if not impossible to determine. The significant decrease in permeability with increasing depth indicates that cleat apertures are becoming narrower as effective stress increases. Gamson et al. (1993) suggested that cleat widths probably range from 0.1 to 2000 μm, with the upper limit probably being restricted to outcrop. Based on analogy with fracture aperture width in conventional reservoirs (Close, 1993) suggested that cleat aperture sizes range between 0.1 and 100 μm. However, most of the available information on cleat width is based on outcrop studies and/or microscopic examination of coal samples that are not under confining pressure. Very little (if any) information is available on cleat apertures in the subsurface and many of the microfractures described by Gamson et al. (1993) may actually be closed under in situ pressures.

A wide range of cleat spacing and/or apertures sizes probably accounts for the wide range (microdarcies to darcies) of fracture permeability in coal beds. From research in fractured carbonate reservoirs, Lucia (1983) developed an equation relating fracture width and spacing to reservoir permeability assuming that the carbonate matrix is impermeable:

$$K_S = \frac{W^3}{Z}(84.4 \times 10^5) \qquad (1)$$

where K_S is permeability (darcies), w is cleat width (cm), and Z is cleat spacing (cm).

This equation can also be applied to coal reservoirs which are also characterized by fracture (cleat) flow and an impermeable matrix (organic material). If the cleat spacing and permeability are known, then the cleat aperture width can be estimated. Highly productive coalbed methane reservoirs in the San Juan and Black Warrior Basins are characterized by cleat spacing ranging from 0.5 to 8 cleats per inch. Direct permeability measurements on coals from these basins are difficult or impossible to obtain, but indirect measurements using drill stem tests and/or production modeling suggest that permeability is generally ranges between 0.5 and 100 md. Based on Eq. (1), cleat aperture sizes in productive coalbed methane wells range between 3 and 40 μm (Fig. 7). Microfractures and secondary and tertiary cleats, have narrower apertures than primary cleats but will probably still be open in the subsurface. Therefore, microfractures and microstructures are probably important to gas migration as suggested by Gamson et al. (1993).

Although the importance of gas migration though the cleat system has been known for some time, diffusion through the coal matrix can affect gas contents and producibility. Methane diffusivity, which measures the number of moles of a methane that can diffuse across a unit area per unit time though the coal matrix, has been measured at 2.93×10^{-7} to 3.70×10^{-5} cm^2/s (Olague and Smith, 1988). The organic fraction of coal is often very heterogeneous and the diffusion coefficients for various macerals or organic and inorganic components may vary significantly (Karacan, 1999). Heterogeneity may exist on several scales ranging from microscopic (maceral-scale) to individual coal seams. For example, the diffusion coefficients for upper Cretaceous Rock Springs Formation coals in the Greater Green River basin correspond with gas content distribution (Fig. 15). Coals with higher gas content coals are associated with low diffusion coefficients, whereas lower gas contents have higher diffusion coefficients. Therefore, in some areas, high diffusion coefficients may result in higher gas migration rates and lower gas contents unless additional thermogenic and/or secondary biogenic gas migrates into the coal and/or is generated in situ by bacteria. On the other hand, extremely low diffusion coefficients may result in such low gas migration rates that dewatering will never result in economic production of coal gas. Laxminarayana and Crosdale (1999) determined that maceral composition and coal rank

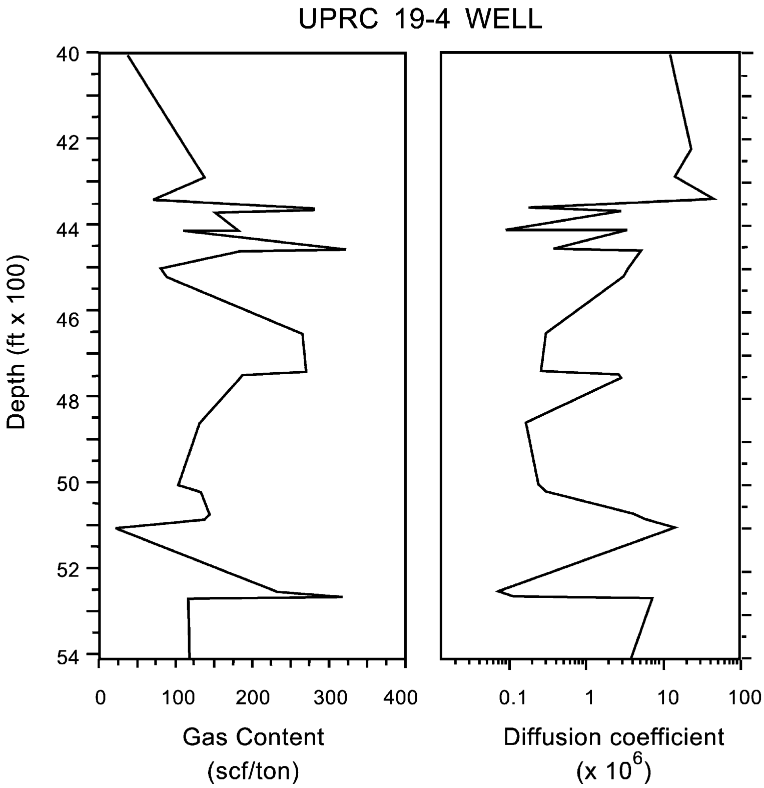


Fig. 15. Relation between gas content and diffusion coefficients for Rock Springs coals in the UPRC 19-4 well, Greater Green River Basin (Scott and Ambrose, 1992). Coals with low diffusion coefficients generally tend to have higher gas contents, suggesting that variability in diffusion coefficients in the subsurface may affect gas content distribution.

also affect the diffusion coefficients in coal beds. Dull coals comprised predominantly of exinite or intertinite generally appear to have a higher effective diffusivity than bright coals that are rich in vitrinite derived from the woody parts of plants. The effective diffusivity progressively decreases with increasing coal rank between vitrinite reflectance value of 0.5% and 1.5% (subbituminous to low volatile bituminous) thereby corresponding with the most rapid loss of volatile matter (carbon dioxide and water) and highest gas generation rate. The change in diffusivity with increasing rank is highest for the dull coals.

Experiments by Harpalani and Ouyang (1999) suggested that the diffusion coefficient will change with the concentration of methane in the coal bed. The diffusion coefficient decreases logarithmically with decreasing methane concentration on the coal. The change in diffusion coefficient may be due to decreasing methane concentrations may result in a change in flow mechanism due to the variability in micropore size distribution or associated with the change in volumetric strain (shrinkage effect) associated with gas desorption.

6. Reservoir conditions

Coal is unique in that it acts as both the reservoir and source rock for coal gases. Present-day reservoir conditions and changes in reservoir conditions during coalification and subsequent uplift and erosion of basin margins significantly influence gas content distribution. Pressure, temperature, and coal reservoir geometry relative to fluid migration pathways strongly affect gas content distribution.

6.1. Reservoir pressure and temperature

Coal sorption capacity increases with increasing pressure and decreasing temperature (Jüntgen and Karweil, 1966; Meissner, 1984, 1987). Because coal storage capacity decreases with decreasing reservoir pressure, basinal uplift is often invoked to explain degassing of coal beds near the surface. During active gas generation coals are often oversaturated with respect to methane resulting in expulsion and migration of coal hydrocarbons, whereas coal beds are often undersaturated with respect to methane at present-day burial depths and temperatures. However, simple uplift alone is probably insufficient to explain undersaturated conditions in many coal basins. For example, converting the pressure axis on a sorption isotherm to an equivalent depth by dividing pressure by 0.433 psi/ft (9.8 kPa/m) shows how coal sorption capacity changes with depth (Fig. 16). Assuming that the basin is uplifted from a maximum burial depth of 9000 to 4000 ft (2743 to 1219 m) after gas generation, the gas content will not change significantly because gas generation essentially ceases at lower temperatures. Significant degassing occurs only at burial depths less than 2500 ft (762 m) and as reservoir pressure gradually declines during uplift, the coals will remain saturated with respect to methane. Because the coals will remain saturated during uplift and pressure decline, subsequent reburial (pressure increase) is required to produce coal beds with abnormally low gas contents and/or undersaturated with respect to methane.

Although pressure is important in determining gas content, temperature rather than pressure is probably better explains undersaturation in coal beds. If the entire coal surface was homogeneous such that each potential sorption site had the same heat of adsorption, then the Langmuir volume or monolayer capacity would be the same regardless of temperature (Brunauer, 1943). However, sorption capacity decreases with increasing temperature (Fig. 17) indicating that the geometry and number of potential sorption sites changes with temperature. Therefore, the surface area available for sorption at lower temperatures is not the same as the area available at higher temperatures. This explains why coal sorption isotherms change shape with increasing temperature; in general, the Langmuir volume decreases and the Langmuir pressure increases (Figs. 17 and 18).

Coals are saturated to oversaturated with respect to methane during active gas generation at high temperatures. However, as reservoir temperature decreases during basinal uplift and cooling, gas generation ceases and the coals become undersatu-

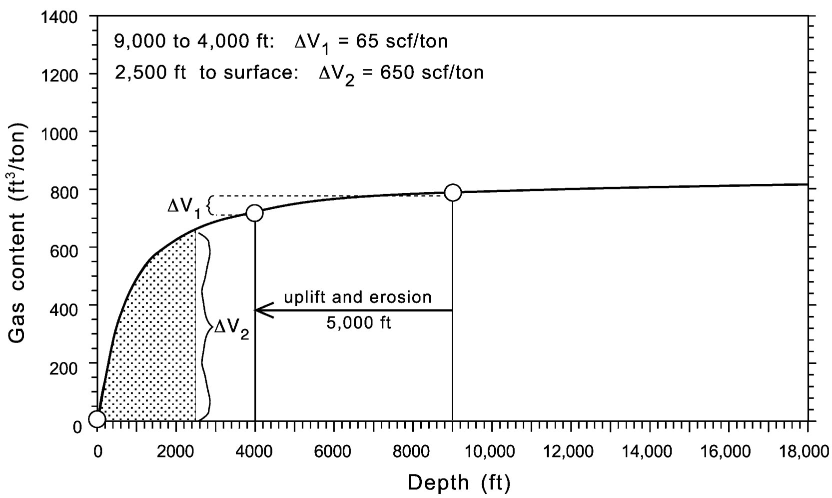


Fig. 16. Changes in gas content during basin uplift. There is little change in gas content even with the removal of 5000 ft (1525 m) of overburden during basin uplift. Significant desorption due to decreasing reservoir pressure occurs only at shallow depths, suggesting that factors other than pressure changes are responsible for undersaturated coal beds. Isotherm pressure was converted to equivalent depth on the basis of a fresh water hydrostatic gradient of 0.433 psi/ft (9.8 kP/m).

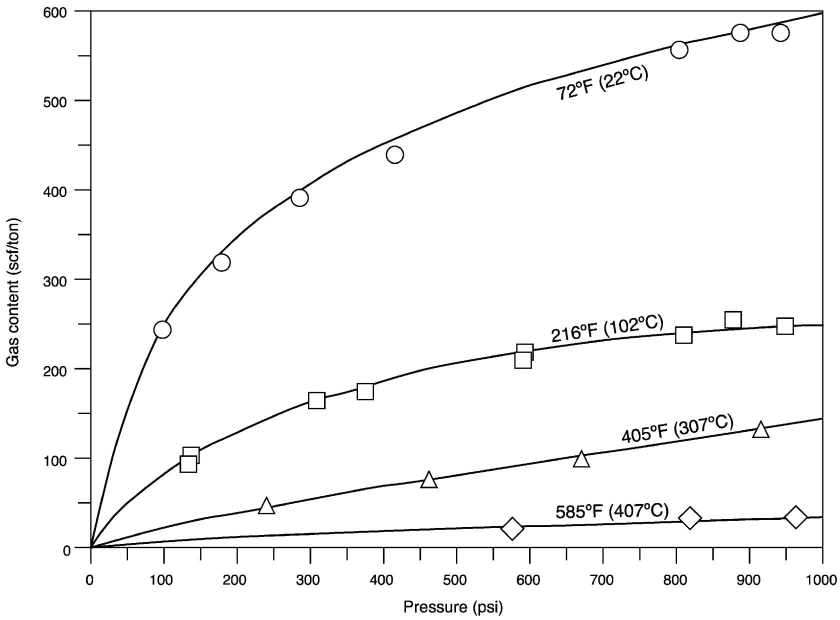


Fig. 17. Changes in coal sorption capacity with increasing temperature. Coal sorption capacity decreases with increasing temperature, indicating that the coal surface area available for sorption changes with temperature. After Yang and Saunders (1985).

rated with respect to methane as the sorption isotherm changes shape (Fig. 18) and the sorption capacity of the coal increases. Note that even if reservoir pressure increases during reburial, gas content will remain constant because at low temperatures active gas generation does not occur and coals will remain undersaturated regardless of how high reservoir pressure becomes. Therefore, the presence of coals saturated to oversaturated with respect to methane in reservoirs where active thermogenic gas generation is not occurring (low temperature reservoirs) indicates the presence of secondary biogenic gases and or the migration of biogenic and/or thermogenic gases.

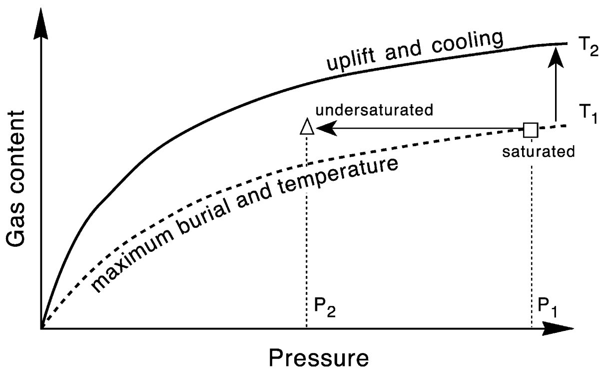


Fig. 18. Coals can store less gas at higher temperatures (dashed line), than at lower temperatures; migration of thermogenic gases from the coal seams occurs when gas generation exceeds storage capacity. Gas generation rates decrease significantly upon uplift and cooling (solid line), and the coal beds become undersaturated with respect to methane as the sorption isotherm changes shape. The presence of saturated to oversaturated coals indicate a dynamic hydrologic system (see Fig. 10). Modified from Scott et al. (1994).

6.2. Coal distribution and geometry

Basinal cooling changes the shape of the isotherm such that lower temperature coal beds are capable of retaining more gas than higher temperature coals assuming all other coal properties are the same. As discussed previously, higher-gas content coal beds are usually associated coal that has reached the thermal maturity level required for gas generation. Once the coals become saturated with respect to methane during coalification, additional gas generated from the coal the gas will migrate from the coal beds to adjacent sandstone reservoirs or laterally within the coals. Therefore, the presence of laterally continuous coal beds in thermally mature parts of the basin are important for the updip migration of coal gas to lower-rank coals. In the Sand Wash Basin, coal is absent in the deepest and thermally mature part of the basin indicating that long distant lateral migration of gas from higher-rank coals was not possible. Therefore, the relatively low gas contents in many shallow coals reflect low coal rank, diffusion of gas from the coal, and limited secondary biogenic gas generation and/or thermogenic and biogenic gas migration and trapping.

Gas migration in a thermally mature basin is not restricted to lateral movement in coal beds nor is gas generation restricted only to coals. Gases generated from other source rocks may also migrate updip and sorb onto undersaturated coals increasing gas content (Figs. 19 and 20). An example of this may be in the northeastern Greater Green River Basin where gas contents in shallow (3500 ft; 1067 m) subbituminous coals exceed 500 scf/ton (15.6 cm^3/g). The area of high gas content coals is within a larger trend of gas production on a structural high suggesting that migration and accumulation of gases has occurred. The area of relatively high gas content may be localized or may cover relatively large areas depending on the type of trap. The distribution and orientation of the coal is also important in trapping the gases. Coal depositional trends orthogonal to gas migration pathways will potentially allow migrating gas to be trapped at permeability barriers associated with facies changes.

6.3. Hydrogeology

Coal bed geometry is also important if permeable coals are the principal aquifer in a regional hydrologic system. If permeable coal beds are oriented to permit recharge along an uplifted margin, meteoric water moving though higher rank coals can transport gas basinward in solution for possible trapping at permeability barriers (Kaiser et al., 1994). The amount of methane dissolved in water is relatively low (tens of scf/bbl; 0.2 m^3/m^3) and depends on pressure and salinity; however, significant amounts of gas can be moved over geologic time. The rate of gas migration will depend on the volume of water moving though the system as well as coal properties such as the diffusion coefficient and permeability. In addition to transporting thermogenic gases generated during coalification, bacteria transported in meteoric water though permeable coal beds can metabolize organic compounds on the coal to generated secondary biogenic gases, which may then be hydrodynamically trapped at no flow boundaries.

The combination of pressure increase due to aquifer pinch-out and artesian conditions and the generation of secondary biogenic gases and/or the migration and subsequent trapping of thermogenic solution gas and secondary biogenic gases act to locally increase gas contents above those expected based on coal rank alone. In areas of active recharge with downward flow potential and/or convergent flow where there is no mechanism for entrapment, gas contents may be relatively low due to flushing (water washing) and diffusion. Therefore, gas contents will increase or decrease above that expected based on a given rank depending on the hydrologic conditions. An important point to remember is that in structurally complex areas with multiple episodes of uplift and burial, several hydrologic regimes may have existed at some point in time. Therefore, lower gas contents may be associated with meteoric recharge associated with unconformities. The unusually low gas contents of some Pennsylvanian coal beds in Great Britain attributed to post-Pennsylvanian uplift and erosion (Ayers et al., 1993) may be due to meteoric flushing.

6.4. Conventional and hydrodynamic trapping of coal gases

The concept of conventional and hydrodynamic trapping of gases in coal beds is often overlooked in coalbed methane exploration because coal gases are assumed to be so tightly sorbed to coal surfaces that

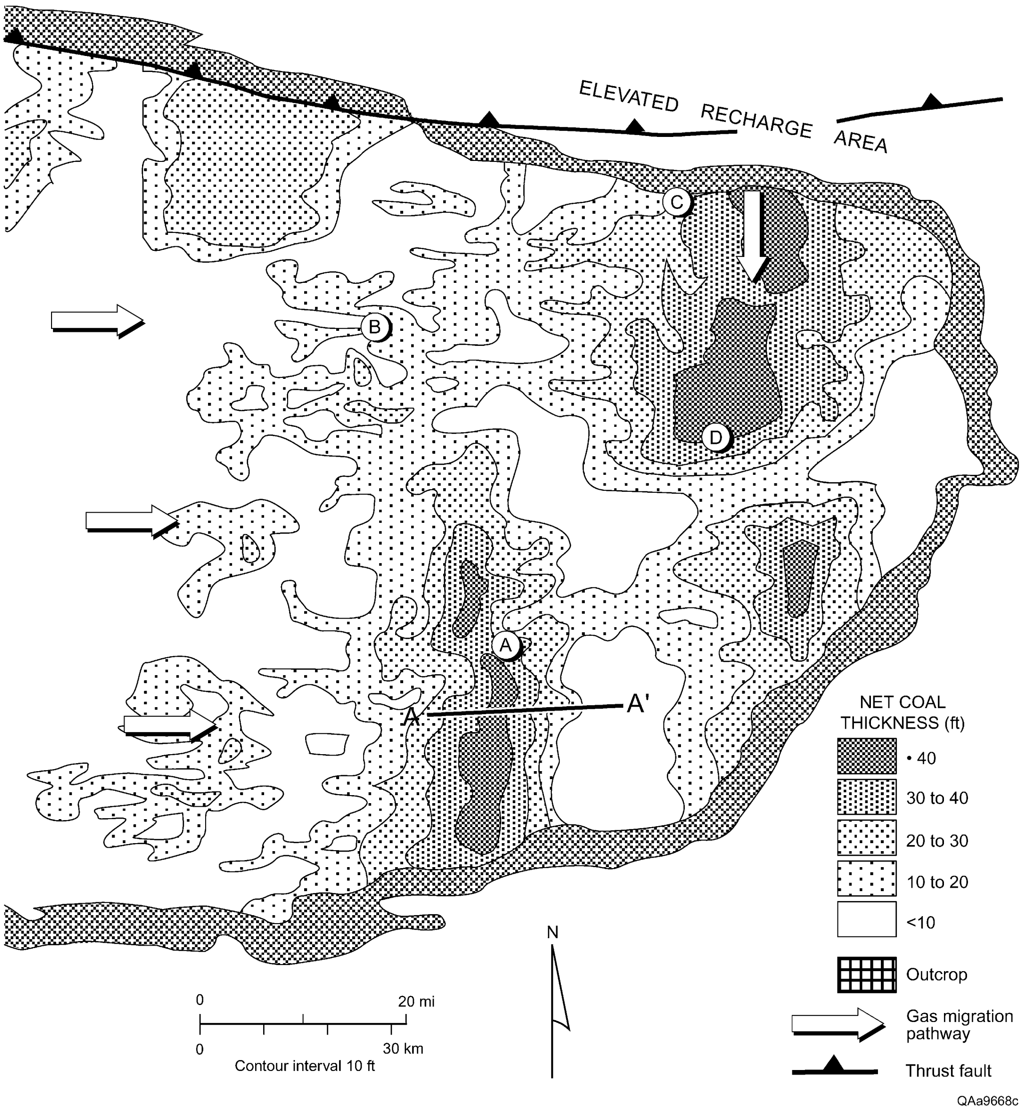


Fig. 19. Influence of coal geometry on the stratigraphic, structural, and hydrodynamic trapping of coal gases. Thermogenic gases migrating updip from thermally mature parts of a basin may be effectively trapped when coal depositional trends are orthogonal to migration pathways (Area A). Less effective trapping of coal gases may occur where depositional trends parallel migration pathways (Area B). Favorable orientation of net coal trends with areas of high annual precipitation allows meteoric recharge and secondary biogenic gas generation to occur (Area C). Conventional and hydrodynamic trapping of thermogenic and secondary biogenic gases occur at permeability barriers orthogonal to ground water flow (Area D).

minimal migration has occurred. Coal bed distribution and geometry are often important in delineating areas of increased gas content. Relatively high gas contents would be expected in areas where updip pinch-out of laterally continuous coals occurs (Fig. 20). Therefore, coal beds oriented perpendicular to gas migration pathways may be more effective in trapping migrating gases than those parallel to migration pathways. Higher gas contents would be expected in areas adjacent to permeability barriers where gases accumulate.

Higher gas contents and production may be enhanced in structural traps as well. For example, the San

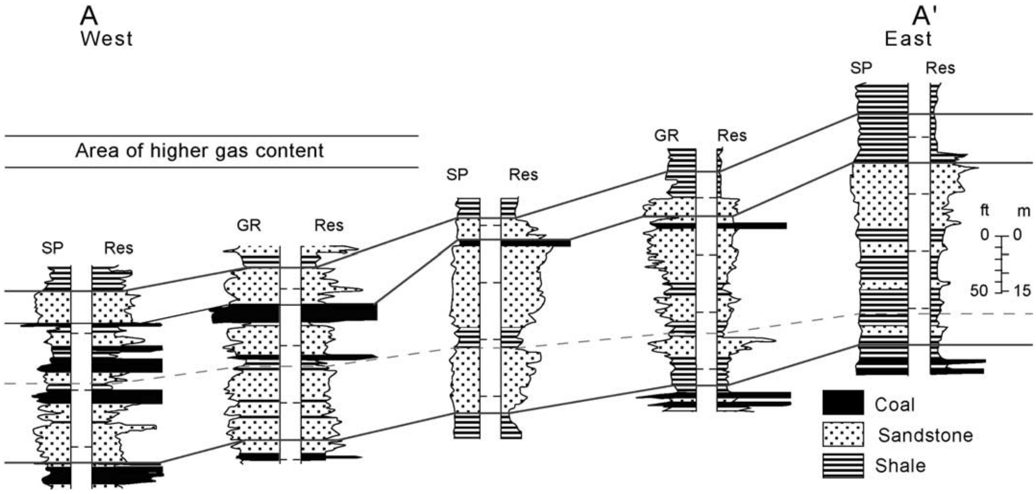


Fig. 20. Updip-migration and trapping of thermogenic coal gases. Migrating thermogenic coal gases are conventionally trapped as coal beds pinch-out updip. Unusually high gas contents, possibly resulting in coals that are saturated to oversaturated with respect to methane, are due to the migration and accumulation of thermogenic gases at permeability barriers. Line of cross-section is shown in Fig. 19.

Juan 32-7 Unit No. 6-17 in the San Juan Basin, known for water-free production since 1953, is located on the crest of a small anticline. Adjacent wells located on the flanks of the structure produce water and less gas (W.B. Ayers, personal comm.). Boreck and Weaver (1984) and Law et al. (1991) noted that higher gas production in shallow subbituminous coals in the Powder River Basin is highest in areas where coal beds drape over thick fluvial sandstones; as much as 400 ft (122 m) of structural relief has been noted. Law et al. (1991) recognized that the gases were biogenic and suggested that the structures must have formed shortly after deposition in order to act as traps for the biogenic gas. However, early trap development is not required if the gases are secondary biogenic gases associated with meteoric recharge that occur after burial and subsequent uplift. Therefore, coal gas origins and the relation among the timing of gas generation and migration, and trap development are important factors to consider when developing exploration strategies.

Hydrodynamic trapping is also an important mechanism for increasing gas contents and requires permeability contrasts to be effective. Permeability barriers are often associated with the landward pinch-out of coal beds, pinch-out against major fluvial channel belts, offset of coal beds by faults, and/or permeability barriers within coal beds such as mineralized cleats or areas of lower cleat density (Fig. 5). These permeability barriers must be perpendicular to meteoric flow direction for the accumulation of gas and higher that expected gas contents (Fig. 19). Multiple episodes of entrapment are possible (Scott et al., 1994).

In the San Juan Basin, pinch-out of coal beds and/or faulting (Ayers et al., 1991), permeability contrasts due to authigenic cements and/or bitumen generated during coalification, and/or a pressure seal associated with a structural hingeline (Combes, 1997), and a major fluvial channel sandstone belt that defines the eastern margin of regional overpressure Kaiser et al. (1991). Thermogenic gases were conventionally trapped against these barriers during the main stage of coalification and hydrodynamic trapping of thermogenic and secondary biogenic gases occurred when the present-day flow regime was developed after the main-stage of coalification. Meteoric flushing of gases near the recharge zone may result in unusually low gas contents (Fig. 21a). The presence or absence of seals will ultimately determine whether or not gases are trapped at areas of convergent flow, thereby resulting in unusually high gas contents (Fig. 21b). Carbon isotopic analyses of methane and carbon dioxide can be used in conjunction with hydrogeologic data to determine coal gas origins and whether or not coal gases accumulate on the updip side of traps

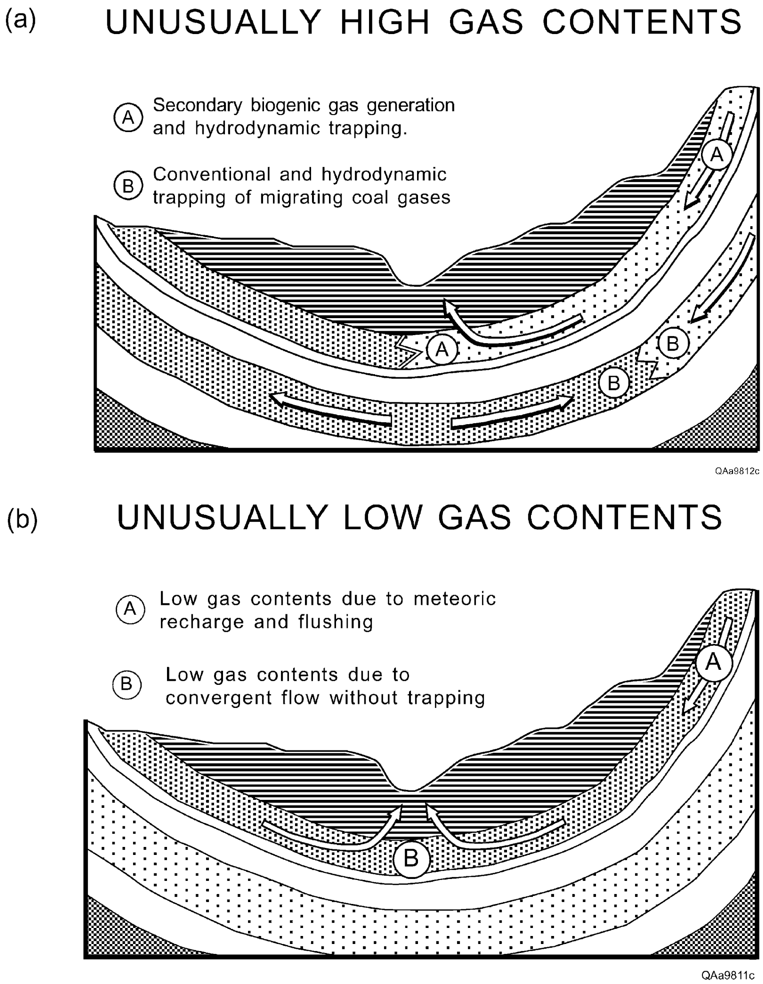


Fig. 21. Summary of high- and low-gas content distribution in basins based on hydrodynamics. (a) Areas of higher gas contents are often found in areas of convergent flow that also have an effective seal to trap the gases, and where secondary biogenic gas generation occurs; (b) areas of lower gas content occur near the outcrop and where convergent flow occurs with no seals to effectively trap the migrating gases.

(migrated secondary biogenic) or the downdip side (migrated thermogenic).

7. Summary and conclusions

(1) Gas contents in coal beds is not fixed but may change when equilibrium conditions in the reservoir are disrupted. Gas content distribution in coal beds is affected by many hydrogeologic factors that can be grouped into three categories: gas generation, coal properties, and reservoir conditions.

(2) The potential for high gas content is directly controlled by the amount of gas generated from the coal which is affected by coal rank, maceral composition, and basin hydrodynamics. Significant methane generation, and therefore, higher gas contents are usually not achieved until a threshold of thermal maturity is reached. Hydrogen-rich coals have greater hydrocarbon generation potential than hydrogen-poor coals. The generation of secondary biogenic gases occurs when meteoric water transport bacteria basinward through permeable coal beds. The influence of gas generation on gas content distribution is generally

on a regional scale although secondary biogenic gas generation can occur locally.

(3) Variability of coal properties affects gas content distribution locally and regionally. Differences in mineral matter (ash) and moisture content, sorption behavior among macerals, diffusion coefficients, and permeability result in significant differences in gas content laterally within individual seams, vertically among seams in a single well bore, and within thicker coal beds.

(4) Reservoir conditions affect gas content on a much smaller scale either locally within a field or among individual wells. Gas content increases with increasing reservoir pressure only if gas generation occurs simultaneously; gas content will not increase if there is no gas available for sorption. Coals may become undersaturated with respect to methane during uplift and cooling because the coal storage capacity decreases with increasing temperature. Gas content is increased where conventional and hydrodynamic trapping of coal gases occurs. Gas content decreases in areas of active recharge with downward flow potential and/or convergent flow where there is no mechanism for entrapment due to flushing.

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