Producing Natural Gas from Coal

Natural gas in coal formations is an important resource that is helping address the world’s growing energy needs. In many areas, market conditions and technological advances have made the exploitation of this resource a viable option. The unique characteristics of coalbed reservoirs demand novel approaches in well construction, formation evaluation, completion and stimulation fluids, modeling and reservoir development.

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With global oil production moving from plateau to decline, worldwide reserves of natural gas take on added importance. Increasingly, gas is viewed as a vital alternative energy source because it is plentiful and burns cleaner than other fossil fuels (see “A Dynamic Global Gas Market,” page 4). In mature, high-demand markets, the industry is looking at unconventional gas sources, such as shale gas, low-permeability sandstones and coalbed methane. These unconventional gas accumulations cannot be exploited in the same way as conventional reservoirs, presenting challenges to both operators and service companies.

Natural gas from coal seams is an important part of the world’s natural gas resource. Improved methods of evaluating coals are now available from new logging measurements and sampling devices. Lighter cements, with the effective use of additives, minimize damage to sensitive coalbed methane reservoirs. Nondamaging fracture-stimulation fluids and innovative hydraulic fracturing designs are being used to improve gas and water flow to the wellbore. Optimized artificial-lift techniques are achieved through the use of intelligent software to promote quick and efficient dewatering of coals. Advanced technologies and industry experience applied worldwide are having a positive impact on coalbed methane (CBM) development.

This article discusses CBM reservoirs, also known as coalbed natural gas (CBNG) or coal seam methane (CSM) reservoirs. First, we review the history of coal exploitation. Next, we discuss the geologic processes that led to the formation of coal, how coals generate and store natural gas, and what makes CBM reservoirs so different from traditional clastic and carbonate gas reservoirs. Finally, case studies from around the world demonstrate the industry’s use of various technologies to evaluate and develop CBM reservoirs.

Minds, Mines and Wellbores
Humans have appreciated the energy value of coal for thousands of years. Early use of coal in fires, dating back to 200 BC, has been confirmed in ancient Chinese records. There is even evidence that Stone-Age inhabitants in Britain collected coal; archeologists have found flint axes implanted in coal seams. The earliest coal finds exploited by humans were used to supplement firewood supplies and were likely found at the surface, along rock outcrops near stream banks. The first evidence that humans dug for coal was found in regions where firewood was scarce. Mining techniques evolved from the primitive method of finding an exposed coal seam along hillsides, then digging into the hill as far as possible to extract the coal. When the operation became too dangerous, these early coal diggers would move to another location along the outcrop. From excavation sites in Britain, it has been determined that as early as 50 AD, Romans mined coal to fuel heating systems and smelting operations. Eventually, pits were dug to access the coal.

Modernization of mining methods, including room and pillar, and longwall mining techniques, enabled larger and deeper operations, exposing mine workers to a variety of hazards. One significant hazard in coal mining is methane gas—a by-product of the coal thermal maturation process that becomes a serious problem in deeper mines. Mine operators alleviated dangerous conditions in the subsurface by using mine-ventilation techniques. Air pumped into a mine through mineshafs and ventilation pipes provided oxygen to workers and dissipated the poisonous and explosive methane. Mining companies also drill coal-degasification wells into coal seams to liberate methane gas prior to mining the coal. Modern ventilation and degasification techniques paved the way for a safer and more productive mining industry. Coal mining in many areas is still not completely safe, so degassing the mines using wellbores ahead of mining operations is an extremely important technique to help reduce the number of mining accidents.

Coal became the energy behind the industrial revolution in Western Europe and across the world, and remains an important resource today. However, there is more to the value of coal than just burning it for heat and electricity; the natural gas that once was merely a hazard can be produced and distributed like conventional natural gas, providing a clean-burning fuel.

Drilling for Coalbed Natural Gas
Coal degasification in mines was first attempted in England during the 1800s, and it is reported that the coal gas was used for lighting the streets of London. The first CBM well to develop gas as a resource was drilled in 1931 in West Virginia, USA. For more than 50 years, CBM drilling activity remained low. In 1978, the US government passed the Natural Gas Policy Act. This legislation allowed companies to receive higher prices for natural gas produced from tight gas reservoirs, gas shales and coal seams. In 1984, the US government offered tax credits for developing and producing unconventional reservoirs. Originally set to expire in 1990, the tax credits were extended two more years because of their positive impact on drilling activity. After the tax credits expired in 1992, low gas prices caused concerns about the economics of CBM development.

Gas price is not the only factor affecting the viability of CBM production. Accessiblity to gas-transportation infrastructure and technical issues related to CBM production, for example low initial gas-production rates, high water-production rates and disposal issues, must also be considered. The positive impact of accessibility to adequate pipeline capacity can be seen in portions of the Rocky Mountains, USA, where the expansion of the Kern River Pipeline in May 2003 has significantly improved gas-production economics.

Today, CBM development is having an impact on the North American gas market. Annual production from 11 coal basins in the US now exceeds 1.5 Tcf [42.9 billion m³], or 10% of the annual US gas production (above). Proven CBM reserves—17.5 Tcf [501 billion m³]—now make up 9.5% of US total gas reserves, and the total US CBM in place is estimated at 749 Tcf.
[21.4 trillion m³]. About 100 Tcf [2.9 trillion m³] are thought to be recoverable (below). Increased gas prices, the continued expansion of the natural gas transportation system and recent advances in oilfield technologies have helped make CBM wells more profitable. Through the years, operators and service companies have gained valuable knowledge from mining research, and practical experience from drilling activity induced by the US tax credits.

As operators drilled and produced CBM reservoirs, it became clear that coal reservoirs behave differently from basin to basin, and even within basins. This behavior largely guides the application of different technologies within a basin or field. In many CBM areas, operators have reduced total exploitation costs while increasing gas recovery by prudent application of new technology.

Canada has just started to produce gas from CBM reservoirs and estimates its in-place reserves to be 1287 Tcf [36.8 trillion m³]. Australia started producing CBM in 1998 and places its total reserves at 300 to 500 Tcf [8.6 to 14.3 trillion m³]. Worldwide, the total CBM in-place reserves are estimated to be between 3500 and 9500 Tcf [100 and 272 trillion m³]. By 2001, 35 of the 69 coal-bearing countries had investigated CBM development but, just as in North America, the pace of future development will depend on economics (next page, top).

### From Peat to Coal

The formation of coal starts with the deposition of organic material from plants, creating peat. Peat is formed by continued subaqueous deposition of plant-derived organic material in environments where the interstitial waters are oxygen-poor. Distinct environments allow the accumulation, burial and preservation of peat, including swamps and overbank areas that may or may not be marine influenced (next page, bottom). In the geologic past, most peat is thought to have formed in deltaic or marginal marine environments.

Coalification, or the conversion of peat into coal, occurs at different rates in different environments. Biochemical degradation initiates the coalification process, but with burial, increasing overburden pressures and subsurface temperatures cause physicochemical processes that continue coalification. As water, carbon dioxide and methane are released, the coal increases in rank, which is a measure of maturity. Coals are divided into rank stages and include, in order of increasing rank: sub-bituminous, high-volatile bituminous, medium-volatile bituminous, low-volatile bituminous, semi-anthracite, and anthracite coals. Although coals contain some inorganic minerals, they are composed largely of macerals, or vegetal compounds, ranging from woody plants to resins.

The three general categories of macerals are vitrinite, liptinite and inertinite. Vitrinite refers to woody plant material, like trunks, roots, branches and stems. Liptinite macerals correspond to the more resistant parts of the plant, such as spores, pollen, waxes and resins. Inertinite macerals represent altered plant material and are less structured. These macerals have a greater carbon content from oxidation processes that occurred during deposition, for example the burning of wood or peat in fires. Maceral data reflect the basic makeup of coals and therefore help geologists determine CBM reservoir potential.

### An Unconventional Reservoir

From the time of deposition, coal is different from other kinds of reservoir rock. It is composed of altered vegetative material—macerals—that function as both hydrocarbon source and reservoir. It is inherently fractured from the...
coalification process, which forms vertical fractures, or cleats. Coal cleats are classified geometrically with the primary, more continuous cleats called face cleats and the secondary, less continuous cleats called butt cleats.

Genetic classification of coal fractures is also common. Endogenetic fractures, or classic cleats, are created under tension as the coal matrix shrinks due to dewatering and devolatilization during coal maturation. These cleat sets are orthogonal and nearly always perpendicular to bedding. In contrast, exogenetic fractures form due to tectonism and therefore regional stress fields dictate their orientation. Shear fractures, oriented 45° to the bedding planes, also are observed.

In virtually all coalbed reservoirs, cleats are the primary permeability mechanism. Like conventional reservoirs, coals can also be naturally fractured. In deeper coal seams, higher overburden stresses can crush the coal structure and close the cleats. In such locations, subsequent natural fracturing tends to be the main permeability driver. Understanding the cleating and

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natural-fracture systems in coals is critical during all facets of CBM reservoir development. Methane generation is a function of maceral type and the thermal maturation process. As temperature and pressure increase, the rank of the coal changes along with its ability to generate and store methane (left). Also, each maceral type stores, or adsorbs, different volumes of methane. In addition, coal can store more gas as its rank increases.

Conventional sandstone and carbonate reservoirs store compressed gas in porosity systems. Methane is stored in coal by adsorption, a process by which the individual gas molecules are bound by weak electrical forces to the solid organic molecules that make up the coal. To assess how CBM wells might produce over time, the sorptive capacity of crushed coal samples are tested and desorption isotherms are constructed (below). Desorption isotherms describe the relationship between pressure and adsorbed gas content in the coal at static temperature and moisture conditions. Coal’s ability to store methane largely reduces the need for conventional reservoir-trapping mechanisms, making its gas content—which is related to coal rank—and the degree of cleating or natural fracturing the overriding considerations when assessing an area for CBM production potential.

Gas generation in coal. As temperature and pressure increase, coal rank changes along with its ability to generate and store methane. Through time, dewatering and devolatization occur, causing shrinkage of the coal matrix and creation of endogenetic cleats.

Coalbed production characteristics. During Stage I, production is dominated by water. Gas production increases during Stage II, as water in the coal is produced and the relative permeability to gas increases. During Stage III, both water and gas production decline.

Sorptive capacity of coal. As coal maturity increases from bituminous to anthracite, the sorptive capacity of coal increases. Tests conducted on coal samples to relate adsorbed gas to pressure—under isothermal conditions—assess how CBM wells might produce over time. The plot shows typical responses in bituminous and anthracite coals (left). The gas storage capacity of coal can be significantly greater than that of sandstones (right).
This storing ability gives coals unique early-time production behavior that is related to desorption, not pressure depletion. Coals may contain water or gas, or both, in the cleat and natural fracture systems, and gas sorbed onto the internal surface of the coal matrix. Any water present in the cleat system must be produced to reduce the reservoir pressure in the cleat system before significant volumes of gas can be produced. Dewatering increases the permeability to gas within the cleats and fractures, and causes the gas in the matrix to desorb, diffuse through the matrix and move into the cleat system, resulting in CBM production profiles that are quite unique (previous page, middle).

Initial production is dominated by water. As the water moves out of the cleats and fractures, gas saturation and production increase and water production falls. When permeability to gas eventually stabilizes, the coal is considered dewatered and gas production peaks. From this point, both water and gas production slowly decline, with gas being the dominant produced fluid. The speed at which the reservoir dewatered depends on several factors, including original gas and water saturations, cleat porosity, relative and absolute permeability of the coal, and well spacing.

Some CBM wells produce dry gas from the start. For example, some wells in Alberta and British Columbia, Canada, and the under pressured portion of the San Juan basin are comparable to conventional reservoirs and produce water-free at irreducible water saturation. Dry gas coalbed production typically declines from the start, exhibiting Stage III behavior.

As with all gas reservoirs, the permeability controls production and largely dictates the amount of gas reserves in coal seams. Local variations in cleat and natural-fracture conductivity and density—how closely cleats or fractures are spaced—lead to wide variations in well performance within some areas of development (above right). For example, 23 wells in a field in the Black Warrior basin, USA, with similar coal thicknesses and original gas contents, were drilled and completed identically, at equal well spacings, but show diversity in production performance because of the local variations in cleat conductivity—permeability. Also, in this basin, cleat and natural-fracture conductivity are greatly affected by the stress on the reservoir. Field-test data confirm the inverse relationship between closure stress and coal permeability; increasing closure stress from 1000 to 5000 psi [6.9 to 34.4 MPa] decreased permeability from 10 to 1 mD.

The unconventional properties and production performance of coalbed reservoirs, including high initial water production and low initial gas production, are largely responsible for the relatively slow uptake in CBM reservoir development around the world. However, the collective knowledge and experiences of the industry in exploiting this resource are showing results in increased CBM production.

**Investigating a New Resource in India**

After reviewing the major coal-bearing basins in India, the Oil and Natural Gas Corporation (ONGC) concluded that the Jharia basin, 250 km [155 miles] northwest of Calcutta, had the best potential for coalbed natural gas production. Three pilot wells were drilled through the Permian-age Barakar formation, which contains up to 18 clearly identifiable coal beds, each from 1 to 20 m [3 to 66 ft] thick. The second pilot hole was cored and logged with high vertical resolution lithodensity, neutron and resistivity measurements from the Platform Express integrated wireline logging tool, FMI Fullbore Formation MicroImager, DSI Dipole Shear Sonic Imager and ECS Elemental Capture Spectroscopy tools. Fullbore cores were obtained in many of the coals and were sent for proximate analysis, rank determination and adsorbed gas content. The logs were analyzed for these same parameters and for cleat porosity.

The first step was proximate analysis from the lithodensity, neutron and gamma ray logs. These log measurements have widely different responses to the various coal components and can resolve them well. The main uncertainty lies in the response parameters of ash, since it may contain varying amounts of quartz, clay, calcite, pyrite and other minerals.' The parameters of volatile matter—mainly organics, wax, carbon dioxide [CO₂] and sulfur dioxide [SO₂]—and fixed carbon are reasonably similar for the bituminous and anthracite coals of interest. In the Jharia well, results of the log analysis were in

6. Proximate analysis is the term used for the identification of the major fractions of the coal, taken as moisture, volatiles, fixed carbon and ash. These fractions have usually been determined by progressively heating and then burning crushed samples and observing the volume of the different fractions removed at each stage until nothing is left but ash. Proximate analysis is distinct from ultimate analysis, in which the weight percent of different elements is determined.
7. Ash is the inorganic constituent, derived from mineral matter, that remains after proximate analysis.

![Production from 23 CBM Wells](image-url)
good agreement with core data (above). The ECS data added detailed information on the composition of the ash and improved the estimate of total ash in washed-out coals, where the density and other logs were more affected by the borehole (see “The Elements of Coal Analysis,” page 16).

The next step was to estimate the volume of adsorbed gas in each seam. Ideally, this would be derived directly from logs. However, the effect of adsorbed gas on the response parameters of coal is small and there are not enough independent measurements to solve reliably for gas. Traditional coal-industry techniques determine gas content from cores, and in their absence, by estimating the rank of the coal from proximate analysis and the gas content from rank, pressure, temperature, and a suitable adsorption isotherm.

The American Society of Testing and Materials (ASTM) ranks coals by the percentage of volatile material after normalizing to dry, ash-free coal. Slightly different ranking criteria were used in Jharia and were applied to both core and log data.

With logs providing information on intervals where core data were missing, ONGC was able to study the quality of the different coal seams. The average coal rank increased with depth, but with a probable change in trend half-way down the section (next page, top). The change in trend is most likely related to a major fault seen on the FMI data at this depth. Coal rank and proximate analysis can also be entered into a suitable sorptive capacity transform to determine the gas in place within each coal seam.²

Cleat porosity was estimated by four different methods: from the porosity seen by microresistivity measurements, by the separation of deep and shallow laterolog curves, by the quantity and type of mineralization seen by the ECS tool, and from the shear-wave anisotropy measured by DSI data. When the borehole is in gauge, the microresistivity measurement gives the most accurate results, and is used to calibrate the ECS and DSI data. In washed-out coals, the ECS log is least affected by hole rugosity, while the DSI and microresistivity logs can be affected more severely. The estimate of cleat porosity adds information on flow capacity to that already obtained on gas volume. These data helped ONGC decide which seams to test, whether to develop this resource and how best to accomplish this.

Huge Reserves and Progress in Canada

Canada’s estimated 1287 Tcf of probable in-place CBM reserves lie primarily in the provinces of British Columbia and Alberta, and can be divided into three main areas, the Alberta foothills, the Alberta plains and the British Columbia foothills. Coals from these areas vary in rank, gas content and accessibility. Canadian coal experts maintain that coal permeability is the main driver of CBM reservoir potential. For this reason, much of the focus when assessing CBM reservoirs in Canada is on understanding cleats and natural fractures, both in outcrop and in wellbores.

Alberta contains vast amounts of coal distributed throughout the southern plains, foothills and mountains. Originally deposited in relatively...
flat-lying peat swamps, organic matter was buried by sediments derived from the west and gradually coalified with increasing heat and pressure after burial. Coals were subsequently folded, faulted, uplifted and partially eroded, resulting in the present distribution of coal across the plains. Coal-bearing strata gently dip westward towards the mountains, where the coals are folded and abruptly turn towards the surface to be reexposed in the foothills.

Coal seams occur within distinctive horizons of the upper Cretaceous Scollard, Horseshoe Canyon and Belly River formations, and within the lower Cretaceous Mannville group strata in the Alberta plains. Coal is also found within the Paleocene Coalspur formation and the Mist Mountain formation of the Jurassic-Cretaceous Luscar/Kootenay groups in the Alberta foothills (below left). Individual coal seams vary in thickness from less than 1 meter [3 ft] to more than 6 meters [20 ft]. Groups of coal seams are separated by 10 to 50 m [30 to 160 ft] of rock. Most coals at shallow depths—less than 1000 m [3300 ft]—in the plains are sub-bituminous to high-volatile bituminous rank. Coals in the Alberta foothills generally are more mature, with ranks from high-volatile to low-volatile bituminous. Alberta plains coals have more predictable cleat characteristics than foothills coals in Alberta and British Columbia because of their limited deformation.

Permeability, formation pressure and reservoir fluid saturation are critical in identifying areas suitable for CBM development. Common methods used to measure permeability in coals, such as injection and falloff testing, often yield inconsistent results because the cleat permeability can be a function of injection pressure. Test intervals may be disturbed by drilling fluids and can be damaged by cementing, breakdown and stimulation fluids, causing adverse effects on test results. Ambiguities occur for a variety of reasons, including inflation of coal cleats and fractures, two-phase permeability and wellbore-storage effects.

8. The theory of Langmuir relates the gas volume adsorbed on ash-free coal to pressure at a given temperature and to two factors that depend on temperature and coal rank. Various researchers have correlated these factors with the results of proximate analysis, so that the adsorbed gas volume can be estimated from logs. See Hawkins JM, Schraufnagel RA and Olszewski AJ: "Estimating Coalbed Gas Content and Sorption Isotherm Using Well Log Data," paper SPE 24905, presented at the SPE Annual Technical Conference and Exhibition, Washington, DC, USA, October 4–7, 1992.

^ Alberta coals. Maps show the distribution of major coal seams (left) and coal rank (right) in Alberta.
The Elements of Coal Analysis

In the simplest technique of proximate analysis from logs, the bulk density is interpreted for ash content, which is then correlated with the other proximates for each rank of coal. Addition of the neutron, gamma ray and photoelectric logs makes the analysis more general and less dependent on local correlations. Unfortunately, some coals tend to wash out while drilling, leading to oversize boreholes and large borehole effects on the logs. In addition, the composition of the components, in particular ash, can vary, creating some uncertainty in the parameters to be used in interpretation.

An alternative technique is based on elemental analysis from neutron-induced gamma ray spectroscopy. Both the ECS Elemental Capture Spectroscopy sonde and the RST Reservoir Saturation Tool device estimate the quantity of minerals in the coal. The advantage of neutron-induced gamma ray spectroscopy is that the majority of the signals of interest arise from elements in the formation and are therefore unaffected by the borehole. In addition, the components of the ash can be more precisely defined from the mineralogy.

Neutron-induced gamma ray spectroscopy tools emit high-energy neutrons that are then slowed down and captured by elements in the borehole and the formation. During capture, a gamma ray is emitted with an energy that is characteristic of the element. A detector measures the gamma ray spectrum, or the number of gamma rays received at the detector at each energy level. This energy may be degraded by scattering in the formation, but there is sufficient character in the final spectrum to recognize the peaks caused by different elements. The first processing step is to calculate the proportion, or relative yield, of gamma rays from each element by comparing the measured spectrum with the theoretical spectrum of each individual element (next page). A mathematical inversion provides the percentage of the principal contributors, such as silicon, calcium, iron, sulfur and hydrogen.

The yields are only relative measures because the total signal depends on the environment, which may vary throughout the logged interval. To obtain the absolute elemental concentrations, additional information is needed. The principle of oxide closure states that a dry rock consists of a set of oxides, the sum of whose concentrations must be unity.1 Measuring the relative yield of all the oxides allows the calculation of the total yield and the factor needed to convert the total to unity. This normalization factor will then convert each relative yield to a dry weight elemental concentration.

Finally, the SpectroLith lithology processing technique transforms elemental concentrations into mineral concentrations using a set of correlations based on the study of more than 400 core samples from different clastic environments.2 The results are expressed as the dry weight percentage of clay, coal, accessory minerals such as pyrite and siderite, and the aggregate of quartz, feldspars and micas. While there may be local variations in these correlations, the major advantage of this technique is that it is automatic, with no user intervention. This contrasts with standard methods for clay determination that depend heavily on user-selected parameters.

Coals are easily identified by their high hydrogen concentration. Quantifying the amount of fixed carbon, volatile material and moisture in coal is more difficult and requires two assumptions. First, there are other sources of hydrogen that must be considered, including water in the cleats, clay water and moisture in the formation, and in the borehole, unless the well was drilled with air. Since these form a consistent background, they can be subtracted to give the hydrogen concentration in coal. Second, different types of coal have different

\[ y = -0.834x + 75.471 \quad R^2 = 0.997 \]
\[ y = -0.171x + 24.034 \quad R^2 = 0.944 \]

\[ y = 0.005x + 0.495 \]
\[ y = -0.171x + 24.034 \quad R^2 = 0.944 \]
\[ y = -0.7762x + 75.575 \quad R^2 = 0.8662 \]
\[ y = -0.2245x + 24.286 \quad R^2 = 0.3507 \]

\[ y = -0.0014x + 0.1816 \]
\[ y = -0.171x + 24.034 \quad R^2 = 0.944 \]
\[ y = 0.005x + 0.495 \]
\[ y = -0.171x + 24.034 \quad R^2 = 0.944 \]
\[ y = -0.0014x + 0.1816 \]

Proximate analysis based on ash content. Excellent correlations have been found with data from three wells in the Fruitland coal interval in the San Juan basin (left). The correlations from the Jharia well in India are satisfactory for fixed carbon but poor for volatile matter (right).
hydrogen contents. However, in a given area or formation, this can be sufficiently consistent to allow a conversion from hydrogen concentration to coal percentage.

Data from the ECS tool allow a quick and automatic proximate analysis at the wellsite. The total ash content is simply obtained from its components, namely quartz, clay, carbonates and pyrite, while the amount of fixed carbon and volatile material can be estimated from correlations with ash content (previous page).

1. In practice, the process is not so straightforward. First, we measure elements, not oxides, but nature is helpful since the most abundant elements exist in only one common oxide, for example quartz [SiO₂] for silicon [Si]. Thus for most elements there is an exact association factor that converts the concentration of the element to the concentration of the oxide. Second, although the ECS tool measures a majority of the most common elements, there are exceptions, the most important being those of potassium and aluminum. Luckily, the concentration of these elements is strongly correlated to that of iron, so that they can be included in the oxide association factor for iron.

Many such correlations have already been established from core data for specific areas or formations. Alternatively, the ECS mineralogy can be combined with other log data in an ELANPlus computation. The resulting proximate analysis is enhanced by the detailed ash description from the ECS sonde, and by the ability of lithodensity and neutron data to distinguish between fixed carbon and volatile matter.

The more detailed ECS mineralogy also helps identify the degree of cleating. The presence of calcite and pyrite indicates a well-developed cleat system in which the flow of water has caused secondary mineralization. However, large quantities of calcite and pyrite suggest that the cleats have been filled or that the coal is of low grade. Quartz and clay have also been observed in cleats, but large volumes of these minerals and a large total ash volume indicate a lower-ranked coal. Such coals will have lost less water and volatile matter during coalification and will therefore have fewer cleats. These observations can be used to identify well-cleated coal by, for example, calcite percentages between 2 and 7%, and pyrite percentages between 0.5 and 5%. Poorly cleated coals have total ash percentages above 45%, clay percentages above 25% and quartz percentages above 10%. Mineral percentages that fall between those of well-cleated coals and poorly cleated coals indicate partly cleated coals. The rules and cutoffs can vary by area and should be established locally from production data.
The coal rank and gas content can be estimated based on proximate analysis. Cleat intensity indicates permeability and hence productivity. Thus, neutron-induced gamma ray spectroscopy, in combination with other logs, provides a continuous record of the major factors needed to evaluate a coal seam and any surrounding sands shortly after the well has been drilled (previous page).

Elemental analysis has an additional role in cased holes, where the RST carbon/oxygen ratio is the most accurate logging method for identifying coals. This technique is particularly useful in wells drilled for deeper targets that have been cased over the coal-bearing zones without recording an openhole density log. The carbon/oxygen ratio is calibrated to coal density, using data from other wells in the area (above). The other elemental yields can be interpreted as already described after allowing for the effects of casing and cement on the silicon and calcium concentrations.

3. Hawkins et al., reference 8, main text.
Nexen Canada Ltd. has run successful tests on shallow plains coal seams using the MDT Modular Formation Dynamics Tester device (next page). After pumping out drilling fluid, the MDT packer module can withdraw reservoir fluid from isolated coal seams at near-virgin conditions. The tool provides accurate flow rate and pressure information, and measures the properties of the recovered fluids in real time. Pressure-transient analysis can be applied to the pressure response to determine coal permeability. Bottomhole shut-in pressure reduces the problem of wellbore storage that can mask the formation response in pressure-transient analysis. Nexen Canada has found that the MDT device is cost-effective and minimizes uncertainties inherent in other coal-permeability testing methods.

Some of the Mannville coals of the Alberta plains are thin-bedded, as seen in a Burlington Resources Canada well FMI image (above). Here, the bulk density log seems to respond to heavy minerals like pyrite in the coal matrix. These are seen as conductive specks on FMI images, giving anomalously high density peaks that cause some potential errors in net-coal estimates. The higher resolution of the FMI tool allows more reliable net-coal thickness measurement. Abundant folds and thrust faults related to Laramide deformation characterize the complex structural geology of the British Columbia and Alberta foothills. The present minimum horizontal stress direction runs northwest-southeast throughout much of the foothills area, roughly parallel to the outcrops, although local stress variations are indicated in borehole-breakout studies. In the Alberta plains, recent studies by Schoderbek D and Ray S: “Applications of Formation Microimage Interpretation to Canadian Coalbed Methane Exploration,” presented at the CSPG–CSEG Annual Convention, Calgary, Alberta, Canada, June 2–6, 2003. (continued on page 23)
Pressure and permeability from the MDT Modular Formation Dynamics Tester device. Nexen Canada Ltd. ran the MDT tool on a well to test coal seams in the Alberta plains. The MDT test position 2 can be located on the log (top). Hydrostatic pressures are plotted in Track 1, along with the gamma ray and caliper data. Results from the spherical flow buildup permeability analysis (middle left) are plotted in Track 2, along with the resistivity data. Buildup data were also used to identify a spherical flow regime (bottom left). Formation pressure determined from the buildup analysis is plotted in Track 3, along with porosity and lithology information. The DFA Optical Fluid Analyzer plot (right) shows pressure, temperature and pumpout volume during sampling, and fluid recovery changes during the test. Drilling mud was recovered initially (brown), then water (blue) with some possible small shows of gas (white).
Analysis of Alberta plains coal seams. A fault was identified during the FMI image interpretation of this Burlington well at a depth of XX79.5 m (Track 4). Faults and associated fracturing have a direct impact on the permeability of coal seams. Gamma ray and caliper data are displayed in Track 1 with borehole orientation. Track 2 contains porosity and lithology information. Fracture apertures exceeding 0.01 cm [0.004 in.] were calculated from FMI data and are displayed with resistivity data in Track 3. Track 4 contains the dynamic FMI image from which bedding and fractures planes were picked. Track 5 shows the dip plots from the interpretation of Track 4. An after-frac survey is included on the right to demonstrate the vertical growth of hydraulic fractures from the perforated coals. The presence of radioactive tracers below the perforations indicates downward fracture growth.
the Alberta Energy and Utilities Board (AEUB) using regional geological data, and drilling and completion records indicate stress variation between upper Cretaceous-Tertiary and lower Cretaceous rock sequences. In addition, image data from the FMI tool have shown faults in these areas (previous page). After-fracture surveys were run to evaluate how hydraulic fractures propagate through the coals and surrounding rock.

In the foothills of northeast British Columbia, the Cretaceous Gates and Gething formations contain the thickest coal resources. Coals in these formations are exposed in the Peace River coal field, along northwest-trending outcrops, where they are mined. In the southeast corner of British Columbia, coal is contained in the Jurassic-Cretaceous Mist Mountain formation, which outcrops in the front range of the Rocky Mountains in the Elk Valley, Crowsnest and Flathead coal fields.

The Gething formation contains over 20 m [65 ft] of cumulative coal in the Pine River area. The formation thins regionally southeastward but maintains cumulative coal thicknesses of about 6 m. A 1980 report of coal exploration in the northern part of the Gething trend provides information on gas contents from drill holes. The data indicate high gas contents—up to 19.5 m$^3$/tonne [620 scf/ton] at a depth of 459 m [1506 ft] in at least one hole. Gething coal rank generally decreases to the east and spans the bituminous range. Face cleats within the Gething coals in the north trend northwest-southeast and, under the current stress regime, may be closed.

The Gates formation thins to the northwest and its coal reserves are not as widespread as those in the Gething formation. Where coal is present in the Gates formation, it normally contains four coal seams with an average total thickness of 15 to 20 m [49 to 66 ft]. In 1996, Phillips Petroleum drilled four wells to test the Gates formation coals at a depth of 1300 to 1500 m [4270 to 4920 ft]. Gas contents measured in these wells were promising and ranged from 6.3 to 29.2 m$^3$/tonne [202 to 935 scf/ton], although measured permeability was low. Face cleats in Gates coal trend northeast-southwest and may be perpendicular to the present minimum stress direction. It is therefore reasonable to surmise that the face cleats in the Gates formation may be open.

The outcrop exposures in the Peace River coal field have given geologists insights into the interrelationships between deformation, cleat development and present stress fields, and their relationship to coal permeability. The combination of depth and deformation may have significantly reduced the permeability in coal seams in the Gething and Gates formations. Intraseam shearing of these coals is thought to have diminished coal permeability.

Coal outcrops provide extensive information on stresses and coal-fracture systems. In the subsurface, many operators rely on borehole imaging to determine the degree of cleating and natural fracturing within the coals; in some wells, shear fractures can be observed using borehole images (above).

Comparison of FMI images from the Alberta plains coal and British Columbia foothills coal. The image of a plains coal shows clear face- and butt-cleat development (top left). The images of the foothills coal help geologists identify significant shear fracturing (top right). Outcrop exposures of Alberta plains and British Columbia foothills coals show bedding planes, face and butt cleats, and shear fractures. Features are marked on the outcrop photographs. The foothills coal (bottom right) shows extensive shear fractures, while the plains coal does not (bottom left). Shear fracturing degrades coal permeability.

In-situ stress determination from borehole images. During drilling operations, stress release around the borehole causes induced fractures and borehole breakout (left). These phenomena indicate the direction of in-situ stresses. The orientations of these features, interpreted from FMI data (right), are used in hydraulic fracture treatment and deviated well designs.

Montage of British Columbia foothills coal interval. The high degree of fracturing in the foothills coals can make fullbore core recovery difficult. The interval shown was cored, but a short but crucial section of core was lost from XX19 m to XX20 m. The FMI image, acquired across the interval, showed that the missing core interval was heavily fractured. Gamma ray and caliper data are displayed in Track 1 with borehole orientation. Track 2 contains porosity and lithology information. Fracture apertures calculated from FMI data are generally lower than in the plains coals and are displayed with resistivity data in Track 3. Track 4 contains the dynamic FMI image from which bedding and fracture planes were picked. Track 5 shows the dip plots from the interpretation of Track 4.

Multiarray induction logs can provide invasion profiles and qualitative comparisons of cleating in coals. In Canada, geologists and petrophysicists with Burlington and Schlumberger are investigating a method to assess coal permeability by examining drilling-fluid invasion using AIT Array Induction Imager Tool data. The AIT device provides resistivity measurements at five depths of investigation, ranging from 10 inches to 90 inches, and with vertical resolutions of 1, 2 and 4 feet. The invasion profile is calculated using a model with a fully flushed zone of diameter $D_f$ followed by a zone of transition to the uninvaded formation at diameter $D_o$. The model has been used to compute the invasion profile in two contrasting wells, a low-permeability foothills CBM test well and a higher permeability plains CBM well. Both wells were drilled with fresh mud systems, providing a good resistivity contrast between mud filtrate and formation-water resistivity.

In the plains coals, the AIT analysis indicated greater invasion where the FMI tool displayed tensional fracturing (next page). The 1-ft [0.3-m] resolution measurement was able to resolve the effects of invasion in the vicinity of a fault seen on
Invasion analysis in the Alberta plains coals. Using a ramp-style invasion model and AIT Array Induction Imager Tool data, the plains coals show invasion up to 3.5 m [11.5 ft] in Track 4. Increased invasion is associated with intervals showing tensional fracturing on the FMI images. The 1-ft resolution AIT measurement was able to resolve the effects of invasion near a fault seen on FMI images at XX79.5 m. Log analysts use this information to gauge the amount of invasion, which may be related to reservoir permeability. Track 1 displays gamma ray and caliper data. Track 2 contains porosity and lithology information, and Track 3 contains resistivity data. Track 4 shows the invasion calculation, and Track 5 contains mechanical properties data, which show a higher Poisson's ratio and lower Young's modulus in the coals. Track 6 displays ELANPlus Elemental Log Analysis lithology results.
Invasion analysis in British Columbia foothills coals. The foothills coals show relatively low invasion, between 1 and 2 m [3 and 6 ft]. Shallow invasion profiles are observed in zones where the FMI image showed a high degree of shear fractures. Track 1 displays gamma ray and caliper data. Track 2 contains porosity and lithology information and Track 3 contains resistivity data. Track 4 shows the invasion calculation, and Track 5 contains mechanical properties data, which show a higher Poisson's ratio and lower Young's modulus in the coals. Track 6 displays ELANPlus lithology results.

the FMI image at XX79.5 m. Further investigation is needed to establish correlations to producibility. In contrast, the shear fractures observed on the FMI images in the foothills coals were associated with zones showing less invasion on the AIT invasion analysis (above). The log analysts believe this analysis provides a dependable way to gauge the degree of invasion, which may correlate to reservoir-scale permeability.

Information from logs, core and outcrop can be used in well construction. Proper cementing of Canadian CBM wells is a major challenge because of the fractured state of coals. Frequently, primary cementing jobs fail to obtain or maintain cement returns to the surface, resulting in low cement tops and greater risk of gas migration. Historically, operators have relied on increasing the amount of excess cement pumped to combat low cement tops, but a novel solution known as CemNET advanced fiber cement has yielded excellent results.

The CemNET slurry contains silica fibers that bridge and plug lost-circulation areas, allowing the slurry to return up the annulus. Operators are benefiting from this unique technology by pumping less cement, significantly reducing cement-disposal costs and potential damage to the coals. The long-term benefit is better cemented wells without remedial cementing costs. In extremely problematic lost-circulation areas, CemNET fibers, coupled with the LiteCRETE slurry system, have proved successful in CBM areas in Canada and in Wyoming, USA. These fluids have been foamed using either nitrogen or carbon dioxide. The move to polymer-free systems and foaming helps ensure improved fluid flow to the wellbore without damaging coal permeability.

Another common characteristic of Canadian CBM targets is that they consist of multiple thin coal seams; it is not unusual to have more than 20 seams present. Schlumberger CoiFrac stimulation through coiled tubing technology has allowed operators to economically perforate and fracture all of these zones individually in a one-day operation. In some areas, Schlumberger is fracturing more than 30 zones per well and can stimulate two wells per day in certain circumstances. Operators benefit from reduced setup costs, reduced gas flaring and significantly reduced time from completion to gas sales. CoiFrac operations are suitable for environmentally sensitive areas since the equipment has a smaller footprint than a service rig and most of the equipment travels to the lease only once.

Efforts to exploit Canada's vast CBM resources have just begun. Armed with the historical knowledge of the coal mining industry, Canada's CBM operators continue to seek out optimal methods for drilling, evaluating, completing and producing coalbed reservoirs.

Development in the Raton Basin
The Raton basin is located in the southern Rocky Mountains, along the boundary between New Mexico and Colorado, USA. It was formed during the late Cretaceous period and the early Tertiary period. The Laramide uplift led to the erosion of the ancestral Rocky Mountains and the creation of an eastward prograding wedge of fluviodeltaic sedimentation, including the deposition of numerous coal beds. The basin contains two
coal reservoir systems: the primary production target, the Vermejo formation coals, at an average depth of approximately 2000 ft [610 m], and the overlying Raton formation coals, the secondary coal target.

The Vermejo coals are moderately continuous because they were deposited in swamps and in floodplains within a fluvial-dominated delta plain. Vermejo coals reach a combined thickness of up to 40 ft [12 m] and average 20 ft [6 m] in combined thickness, with an average individual seam thickness of 2.6 ft [0.8 m], over a 275-ft [84-m] gross interval. By contrast, the Raton coals are thinner and less continuous because their deposition was typically overbank into the backswamp environments associated with meandering river systems. Raton coals can exceed 75 ft [23 m] in gross thickness, but individual seams average 1.5 ft [0.5 m] in thickness.

During the Miocene epoch, an igneous complex called the Spanish Peaks intruded into the basin.14 Igneous activity formed a complex network of dikes, sills and fractures that have influenced the reservoir characteristics of both coals and sandstones (right).15 The mid-Tertiary burial and the late-Tertiary uplift and erosion in the southern part of the basin, coupled with the late-Tertiary intrusions and associated heating, caused the overall fluid pressure in the basin to drop.15 This complicated geologic history has made the Raton basin difficult to understand and develop.

With CBM operations in several US basins and over 1.9 Tcf [54.4 billion m³] in CBM reserves, El Paso Production Corporation has studied the Raton basin extensively since 1989. El Paso has drilled more than 350 wells and has recovered more than 42,000 ft [12,800 m] of full-bore core in the basin, making these coals some of the most studied CBM reservoirs in the industry. Vast amounts of lithologic, gas-content and log analysis computations. Since 2001, El Paso has acquired Platform Express and ECS data on 290 wells, and DSI and FMI data on strategically located wells across the Vermejo Park Ranch. Borehole images have been used along with outcrop and core data in a comprehensive effort to model the basin’s fracture systems.20

Footnotes:


Even with this extensive database, the Raton basin remains a challenging area in which to operate because of numerous complicating factors. First, gas-content values in the Vermejo and Raton formation coals vary across the basin, ranging from 50 to more than 400 scf/ton \([1.56 \text{ to } 12.48 \text{ m}^3/\text{tonne}]\), on an in-situ basis. The deeper Raton formation coals are typically gas-saturated and productive potential. The intrusive bodies have changed bituminous coal into higher rank coal, so the impact on gas content is inconsistent and not yet predictable.

El Paso’s understanding of the reservoirs and the basin as a whole has allowed the company to improve its models and adopt strategies in drilling, completion, stimulation and production that maximize environmentally sound exploitation. For example, El Paso drills Raton basin CBM wells using air as the drilling fluid, thereby minimizing the damage to the coal’s cleat and natural-fracturing systems. Wireline logging is accomplished with air in the borehole by acquiring epithermal neutron data in combination with the Platform Express tool.\(^{21}\)

The Platform Express tool is designed to minimize the adverse borehole-rugosity effects on the density measurement commonly observed in coals and in air-filled boreholes. Detailed lithology of both the coals and the surrounding low-permeability gas sandstone is computed using the ECS tool, and SpectroLith and ELANPlus processing. Log-based proximate analysis is also performed in the coals to determine the percentages of volatile matter, fixed carbon, moisture and ash, based on benchmarking to voluminous core data. From these percentages, coal rank and adsorbed gas volume can be estimated (above). In addition, the logs provide a qualitative estimate of the degree of cleating.

The DSI tool also provides El Paso with valuable information on fractures and in-situ stress fields by measuring shear wave anisotropy. Anisotropy causes shear waves to split into two components, one polarized along the direction of

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**Table:**

<table>
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<th>Depth (ft)</th>
<th>Gas Saturation</th>
<th>Water Saturation</th>
<th>Coal</th>
<th>Cleat</th>
<th>Cleated</th>
<th>Poorly Cleated</th>
<th>Fracture Permeability</th>
<th>Hydrocarbon</th>
<th>Water</th>
<th>Moisture</th>
<th>Volatiles</th>
<th>Fixed Carbon</th>
<th>Ash</th>
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\(^{21}\) Characterizing coal and noncoal resources. With ECS Elemental Capture Spectroscopy and Platform Express data, an ELANPlus analysis is computed. Lithology is presented in Track 4. Proximate (Track 5) and cleat analysis (Track 6) provide information on coal quality. Computed permeabilities are in Track 7 and estimated gas production is displayed in Track 8. El Paso also uses the ELANPlus processing to calculate the reserves in the surrounding sandstones and siltstones.
maximum velocity, and the other along the direction of minimum velocity. With two transmitters and two sets of receivers oriented perpendicular to one another, the DSI tool can measure both the in-line waveforms from receivers oriented in the same azimuth as the transmitter, and crossline waveforms from receivers oriented 90° from the transmitter.22

During the DSI measurement, there is no way to know how the signals are oriented with respect to anisotropy. However, with both in-line and crossline waveforms, it is possible to perform a mathematical rotation to find the azimuth of the fast shear wave, and to determine the velocities of both fast and slow shear waves. This rotation relies on the fact that the crossline waveforms should vanish when the measurement axis is aligned with the anisotropy axis. The processing also computes the energy in the crossline waveforms as a percentage of the total waveform energy. When the two axes are aligned, the result is known as the minimum energy and is zero if the rotation model is correct. The maximum energy is the energy at 90°. The difference between minimum and maximum is known as energy anisotropy and is the principal measure of anisotropy from DSI data.

The polytectonic history of the Raton basin has introduced other complications. For example, late-Tertiary changes in the regional stresses from compression to tension, thought to be caused by Rio Grande rifting to the west, have major implications for field development, especially in terms of well placement and stimulation practices. Prior to acquisition of key log data by El Paso, the Raton basin's maximum principal stress direction was believed to be east-west, consistent with a compressional basin model. FMI images and DSI anisotropy data have shown that the maximum principal stress direction is actually north-south (above right). This change has significant implications for planning field development and well stimulations (see “Refracturing Works,” page 38). Fracture stimulation will tend to propagate in this north-south direction and, given an east-west Laramide-age open natural-fracture system, optimal drainage aspect ratios are anticipated. As a result, where possible, development wells are not positioned due north-south or east-west of one another; this maximizes ultimate drainage areas and gas recovery.

Currently, El Paso is assessing two different hydraulic fracture stimulation treatments in the Raton basin. The first is a low-polymer borate fracturing fluid and higher concentrations of proppant, delivered using coiled tubing and straddle packers. This technique has been beneficial in wells where six to eight different coalbed layers have been identified for stimulation. These polymer-base fluids have been more successful in areas that initially produce large amounts of water, and where cleat- and fracture-system damage is of less concern. However, in areas where the coals initially produce low volumes of water, degrading the permeability to gas within the cleats and fractures is likely with polymer liquids. In these areas, El Paso is evaluating a second technique of pumping foamed nitrogen down casing to hydraulically fracture the coals and place smaller proppant concentrations.

Coaled Completion Strategies
Coalbeds often are adjacent to productive sands that have dramatically different mechanical properties. Coal has a higher Poisson’s ratio and a lower Young’s modulus than sand, so coals tend to transfer overburden stress laterally and maintain higher fracture gradients. Cleating and natural fracturing in coals create complex hydraulic fracturing scenarios that are extremely difficult to model.23

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21. The epithermal neutron measurement is based on the slowing down of neutrons between a source and one or more detectors that measure neutrons at the epithermal level, where their energy is above that of the surrounding matter. In air-filled boreholes, the lack of hydrogen dramatically changes the thermal neutron population near the detectors, invalidating the response of a standard thermal neutron log. The epithermal measurement is less affected by the borehole and by using an array of back-shielded detectors, as in the APS Accelerator Porosity Sonde device, can be calibrated to give porosity. Also, by measuring neutrons at the epithermal level, the effects of thermal neutron absorbers are avoided.


Gas lock is a condition sometimes encountered in a pumping well when dissolved gas, released from solution during the upstroke of the plunger, appears as free gas between the valves. On the downstroke, pressure inside a barrel completely filled with gas may never reach the pressure needed to open the traveling valve. In the upstroke, the pressure inside the barrel never decreases enough for the standing valve to open and allow liquid to enter the pump. Thus no fluid enters or leaves the pump, and the pump is locked. It does not cause equipment failure, but with a nonfunctional pump, the pumping system is useless. A decrease in pumping rate is accompanied by an increase of bottomhole pressure (or fluid level in the annulus). In many cases of gas lock, this increase in bottomhole pressure can exceed the pressure in the barrel and liquid can enter through the standing valve. After a few strokes, enough liquid enters the pump to break the gas lock, and the pump functions normally.


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30. Oilfield Review

Devices such as the DSI tool help determine accurate in-situ stress magnitudes and directions to improve hydraulic fracturing designs. In addition, borehole images allow determination of the preferred fracture plane, which reflects the current stress conditions at the wellbore. This information is used to devise perforation strategies that maximize the efficiency of hydraulic fracturing operations by reducing near-wellbore tortuosity effects that lead to early screenout.24 The relationship between coal cleats and horizontal stresses is equally important and can help explain CBM production variations between wells and between production areas.

The effectiveness of hydraulically fracturing individual coals has been debated because of their inherent complexities. Proppant volumes used in coal stimulations can be as high as 12,000 lbm/ft [17,700 kg/m] of coal, but the effective hydraulic fracture half-lengths are disappointingly low—rarely documented over 200 ft [60 m]. Hydraulic fractures can grow out of zone or develop into complex fracture networks within the coal, often damaging coal permeability when polymer-base fracturing fluids are used.25

Some experts believe that CBM reserves would triple if fracturing coals were as effective as fracturing sandstones. Mechanical properties from DSI data show the stress contrast between coals and surrounding layers, enabling engineers to predict fracture height and improve stimulation treatments (left). In areas where adjacent sandstones have productive potential, operators are reexamining their perforating and stimulation strategies in coals and sandstones. A technique called indirect vertical fracturing (IVF) initiates the fracture in the less-stressed sandstones above or below the coal to ensure adequate fracture propagation.29 In coals, this technique succeeds because the vertical permeability of coal is frequently greater than its horizontal permeability, reducing the need for a hydraulic fracture to completely pass through the coal to effectively drain it. Another reason for the success of this technique in coals is due to the contrast in fracture gradient between the surrounding clastic rocks and the coal. This difference helps ensure fracture connection with the coal seam along the length of the hydraulic fracture. This technique was first demonstrated in the Fruitland coal and Picture Cliff sands of the San Juan basin in New Mexico and is currently being employed successfully in the central Rocky Mountains.
Dewatering Methods
In a majority of CBM wells, water production is crucial to the gas-production process. Successful dewatering requires uninterrupted pumping operations to decrease the bottomhole pressure so gas will desorb from the matrix and diffuse into the cleat systems as quickly as possible. Pumping methods vary according to area lift requirements and economics. Pumps must handle large volumes of water and be resistant to coal fines, proppant damage and gas lock. These requirements have made progressing cavity pump deployment one of the more attractive lift methods for CBM applications. The selection and design of an appropriate lift method often are not straightforward and should focus on capacity, efficiency and dependability.

Schlumberger engineers and scientists at the Abingdon Technology Center and Cambridge Research Center in England are developing software to aid in artificial-lift selection specific to gas-well dewatering. The Gas Well Dewatering Selection Tool (GDST) brings consistency to this critical selection process by utilizing the available well information to select the most appropriate lift method. This software helps Schlumberger field engineers, interacting with the clients, use a selection process based on sound engineering practice. The tool provides a case-based reasoning engine and sensitivity analysis to obtain recommendations with defined confidence levels.

The economic drivers for CBM wells differ from conventional gas wells in that most wells will not require indefinite or increased dewatering through time. The GDST program enables the engineer to make several iterations to determine the best lift method. The program does not provide for comparative economics of lift methods, although economic limitations of the proposed lift methods are considered in the selection process. The tool is designed to aid in the selection of lift methods, including those that may not have been considered previously. (above right). An optimal dewatering strategy, coupled with nondamaging cementing and stimulation techniques, helps expedite water movement out of the coal’s fracture permeability network, thereby increasing well productivity.

Gas for the Future
The exploitation of CBM resources is progressing steadily. In the USA, natural gas prices have made many areas—for example the Green River region, Piceance basin, Arkoma basin and Cherokee basin—more attractive for CBM drilling, although some are not yet producing significant volumes of natural gas. Tremendous CBM reserves in the US Gulf Coast region have yet to be tapped, but CBM activity has started in the Cook Inlet, Alaska, USA. Worldwide, many countries have just started investigating their CBM resources. Local activity will grow out of necessity and out of the knowledge of how these reservoirs behave.

Formation-evaluation methods, together with fullbore core data, are helping the industry understand coal reservoirs. Log processing techniques yield detailed lithology, and proximate and permeability data. Clean and fracture systems are studied along with important local stress information through the use of borehole imaging techniques to more thoroughly appreciate coal-seam permeability.

Coal-seam permeability, controlled by events that occurred during deposition, maturation and tectonism, has surfaced as the most important factor in CBM production. Coal fracture systems must be connected successfully to the wellbore through nondamaging stimulation methods. However, complex stress profiles and coal fracture systems make hydraulic fracture propagation in and around coals difficult to simulate.

New fracture-monitoring technology promises real-time images of hydraulic fracture creation. Early passive-seismic technologies performed primitive hydraulic fracture monitoring, but processing these data was tedious and time-consuming, and did not provide real-time information during fracturing operations. The StimMAP hydraulic fracture stimulation diagnostics software allows real-time, onsite imaging of hydraulic fracture seismic events, resulting in improved job placement, enhanced well productivity and a better understanding of fracture geometry for future field-development decisions.

Although the industry’s knowledge of coal is vast and growing, modeling CBM reservoir behavior has been a challenging task. Schlumberger has improved coal reservoir modeling capabilities in ECLIPSE Office integrated simulation manager and case builder software. This new software incorporates isotherm data and handles uncertainties, and will have the capability to manage multiple gas types.

The nature of CBM development demands careful economic consideration. Low-cost solutions can help, but technological advances in drilling, formation evaluation, completion, stimulation, production and reservoir modeling will have a far greater impact. With immense worldwide reserves and a growing infrastructure to exploit them economically, coal ranks high on the short list of unconventional fuels awaiting future development.

—MG, JS