Learning to Produce Coalbed Methane

Coalbed methane wells have turned conventional oilfield thinking on its head. Coal seam gas is exploited by wells that are drilled and completed to start life producing water; gas flow only starts after the reservoir pressure is reduced.

Methane in coal has traditionally presented miners with, at best, a nuisance, and, at worst, a major explosion hazard—something to be avoided. Some coalbeds are vented through boreholes before mining, but in the majority, the methane is diluted to below its lower explosive limit (5 percent). In the USA alone this process is wasting hundreds of millions of cubic feet of gas each day.

Now explorationists are seeking coalbed methane and drilling production wells into coals that may never be mined. This new energy source is attracting attention worldwide and in the USA, particularly, is creating a great deal of activity.

Coal is both source rock and reservoir for coalbed natural gas which can vary in composition from 95 to 98 percent pure methane to more than 50 percent carbon dioxide and occasionally more than 10 percent ethane. Unlike a classic production zone, the majority of gas is not compressed into conventional pore spaces but attached within the coal’s molecular structure, which gives it “microporosity.” Although conventional porosity can be as little as 1 to 3 percent, this molecular sorption commonly results in an “equivalent porosity” greater than 20 percent porosity for a coal that is fully saturated with gas.1

Part of this very low porosity is a network of small fractures, called cleats, which are usually filled with water. This water must be produced to reduce reservoir pressure which then allows the gas to desorb from the coal and flow via the cleats into the wellbore (next page).

The first significant coalbed methane activity has been in the US which contains resources of around 400 trillion cubic feet (Tcf) (see page 29). This year new coalbed methane wells may represent nearly half of US gas well completions. At the end of last year, some 6,000 coalbed wells were estimated to be in production.

The significance of this rapid growth in production in the US has not been lost on the rest of the world. Other countries are now looking for opportunities to tap the gas instead of mining the mineral. Alberta, Canada has methane reserves of at least 150 Tcf. The Alberta Geological Survey has set about confirming this potential and stimulat-

For help with this article, thanks to Darwin Ellis, Schlumberger-Doll Research, Ridgefield, Connecticut, USA; Hugo Morales, Dowell Schlumberger, Tulsa, Oklahoma, USA; Jerry Norton, Dowell Schlumberger, Prestonburg, Kentucky, USA.

ing subsequent exploration and recently launched a research project calling for subscriptions from interested companies.2

Australia estimates its gas in place at 1,000 to 2,000 Tcf. As most of the coal is near populated coastal areas, it may be exploited in preference to other gas resources which tend to be offshore and remote from users. In Europe, Poland, France and the UK are taking a leading role in this potential, while countries in the Far East such as Indonesia are also looking to coal as a future gas source.

Despite this recent flurry of activity, coalbed methane production is not a new phenomenon—the first recorded well was drilled in 1931 in West Virginia, USA. In the 1950s attention switched to the San Juan basin in Colorado, USA where a number of wells were drilled. But production was not easy. Coal fines from the extremely brittle reservoirs often caused problems, blocking wells and clogging surface equipment.

Although some success was recorded in the 1950s, the current generation of methane producers dates from 1977 when Amoco Production Company completed its first well. This was also in the San Juan basin where gas-saturated coal beds are generally thick (up to 150 feet [15 meters]), no deeper than 4,000 feet [1,220 meters], and in some cases overpressured with a gradient of 0.55 to 0.60 psi / foot which enables production of gas without the usual prior production of large volumes of water. In the US, the other main basin for methane production is Black Warrior in Alabama, which has a series of thinner beds (no more than about 5 feet [1.5 meters]) ranging in depth from outcrop to 3,500 feet [1,070 meters].

Activity remained low until 1984 when the US government introduced a tax credit for unconventional fuels, worth around $0.80/MM BTU (British Thermal Units)—current prices range from $1.20 to $2.60/MM BTU. This sparked further drilling in San Juan, Black Warrior and a host of other US coal basins (next page). To some extent, the expected expiration of the tax credit at the end of 1990 motivated the past year’s activity.3 A recently announced two-year extension is helping maintain drilling levels. A key element in achieving cost-effective results will be continued research into coal’s complex production mechanisms.

Much of the US research effort to date has been led by government agencies. In the 1970s, the US Bureau of Mines initiated a research and development program that looked at many of the problems associated with drilling and producing coalbed methane wells, especially mine safety. In conjunction with United States Steel Corp. (now USX), the Bureau developed a 23-well demonstration project at the Oak Grove mine, Alabama, USA.

Recent core tests have demonstrated that around 73 percent of the original gas in place has been removed from the Oak Grove coal. This result is complicated by the fact that the production exceeded the estimated gas in place for the coal zone that was completed—indicating that some of the produced gas came from adjacent strata.4

Coalbed methane resources of the US Total resource=400 Tcf

US distribution of coalbed methane reserves in Tcf. The introduction of a tax concession spurred activity across the country. With new economic conditions starting next year, it is not clear where activity will continue. But there is general agreement that coalbed methane production is here to stay. (Source: Gas Research Institute and ICF Resources Inc.)

Then, around 10 years ago, the Gas Research Institute (GRI) began coordinating testing and analysis of the numerous mechanisms that govern reservoir storage, release and production of coalbed gas. A field laboratory was established at Rock Creek, a few miles north of the original Oak Grove site.

Earlier this year in Colorado’s Piceance basin, a new research program began with the spudding of a horizontal well funded by the US Department of Energy. The three-year, $4.3-million project is designed to determine the commercial feasibility of drilling and producing from tight sands and coal seams at a total depth of nearly 8,000 feet [2,440 meters] with a horizontal section of 500 feet [150 meters].

Over the years, research has helped improve understanding of coalbed reservoirs and established some ground rules for their production. To produce gas at economic rates the coal must have an extensive cleat system to provide permeability and a flow path to the wellbore. There are two types of cleat—put simply, they are longitudinal (face) cleats and orthogonal (butt) cleats.

January 1991
Because of this, permeability can also have a directional element. And although, as with conventional reservoirs, intrinsic permeability and static reservoir pressure are key elements in controlling a coal seam's pressure decline, a new element in the equation is gas desorption pressure.

Reservoir pressure must be reduced to less than the desorption pressure so that methane begins to desorb from the coal's microporosity closest to the cleat. This creates a concentration gradient within the coal causing more methane to diffuse through the coal matrix (according to Fick's equation, which states that gas will move from an area of high concentration to low concentration). Desorption time characterizes how long methane takes to diffuse through the coal particle to the cleat. At the cleat system, gas together with water travels in Darcy flow toward the wellbore.

From looking at one point in the reservoir, the net result of these mechanisms is that first water alone is produced. Then, as the pressure is reduced, water continues to flow, though from deeper in the coal, and small, unconnected bubbles of desorbed gas begin to form. Finally, the concentration of desorbed gas becomes high enough

---

### Basic Properties

<table>
<thead>
<tr>
<th>Chemical Formula</th>
<th>Bulk Density g/cm³</th>
<th>Mol. Weight</th>
<th>Occurrence in Sedimentary Rock</th>
<th>Elemental Weight % (calculated from formula)</th>
<th>Observed Trace Elements</th>
</tr>
</thead>
<tbody>
<tr>
<td>Anthracite</td>
<td>1.51</td>
<td>12.85</td>
<td>In shales and organic-rich beds, organic source.</td>
<td>H: 2.8, C: 93.5, O: 2.7, H: 1.0</td>
<td>U</td>
</tr>
<tr>
<td>Bituminous Coal</td>
<td>1.27</td>
<td>14.27</td>
<td></td>
<td>5.6, C: 84.2, O: 8.7, H: 1.5</td>
<td>S</td>
</tr>
<tr>
<td>Lignite</td>
<td>1.23</td>
<td>16.45</td>
<td></td>
<td>5.2, C: 73.0, O: 20.8, H: 1.3</td>
<td></td>
</tr>
<tr>
<td>Peat</td>
<td>1.10</td>
<td>21.76</td>
<td></td>
<td>4.1, C: 55.2, O: 37.5, H: 3.2</td>
<td></td>
</tr>
</tbody>
</table>

### Nuclear Logging Parameters (calculated by SNUPAR)

<table>
<thead>
<tr>
<th>Gamma-gamma Logging</th>
<th>TDT Logging</th>
<th>Neutron Logging</th>
<th>Acoustic Logging Parameters</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electron Density Index g/cm³</td>
<td>Litho Density g/cm³</td>
<td>Electron Density Index g/cm³</td>
<td>Neutron Logging</td>
</tr>
<tr>
<td>Anthracite</td>
<td>1.55</td>
<td>1.47</td>
<td>0.16</td>
</tr>
<tr>
<td>Bituminous</td>
<td>1.34</td>
<td>1.24</td>
<td>0.17</td>
</tr>
<tr>
<td>Lignite</td>
<td>1.29</td>
<td>1.19</td>
<td>0.20</td>
</tr>
<tr>
<td>Peat</td>
<td>1.14</td>
<td>1.04</td>
<td>0.25</td>
</tr>
</tbody>
</table>
to establish two-phase flow toward the wellbore (previous page).

Identification of a coal seam and evaluation of production efficiency cannot be achieved using only methods developed for the conventional oilfield. Laboratory analysis of cores using techniques borrowed from the mining industry are being combined with electric wireline logs in an effort to chart producibility (see “Classifying Coal,” right).

Electric logs have been used to locate coal seams as far back as 1931. At that time, the high resistivity of coal beds (usually greater than 10 ohm-meters [ohm-m], depending on seam thickness) caused distinctive anomalies on resistivity curves. Logging soon became an accepted tool in defining and evaluating coalbeds for the mining industry.

Coal was also found to exhibit an anomalous response on the density log—often less than 1.75 g/cm³. The most prolific coals for gas production typically register 1.2 to 1.3 g/cm³. Most other logging responses in coal also vary distinctly from those obtained in conventional reservoirs (previous page, middle, and below).

After locating a coal seam, there is a need for more detailed reservoir information. Gas detection in clastic reservoirs is traditionally achieved using the Compensated Neutron Log (CNL) tool which responds primarily to the hydrogen content of the formation in combination with density porosity measurements. Unfortunately, the neutron porosity reading in coal falls in the area of 80 to 100 porosity units [p.u.], a range where the tool’s sensitivity is poorest. And, because the theoretical difference between a coal with gas in it and a coal with no gas is only about 3 p.u. and the actual response is not known, measuring gas in place is virtually impossible.

The alternative has been to draw an empirical relationship between logs and cores. At the heart of this is an approximate relationship between rank (a measure of coal’s geologic maturity) and coal’s ability to sorb gas—higher rank can sorb more gas. However, rank cannot indicate how much of this capacity to sorb is actually filled with gas.

First, there is a need to determine the coal’s rank. The mining industry has traditionally employed three methods for this: reflectivity, combustion and proximate analysis. Proximate analysis evaluates weight percent ash, fixed carbon and volatile matter, to calculate rank. Although logging does not involve pyrolysis used in proximate

---

### Classifying Coal

Coalbed methane production has seen the merging of two cultures: oilfield and coal mining. Much of the past work on the subject has been carried out by the coal industry, anxious to avoid explosions caused by escaping gas. Mining tests and terminology have now been adopted by the gas industry.

The mainstay of the mining industry’s approach to determining coal qualities has been core testing. At the outset, a sample is placed in a canister at atmospheric pressure and the amount of gas it releases is the “free methane” value. Because use of pressurized core barrels is rare, it is usually necessary to correct for the “lost gas” released while the core was in transit to the surface.

Next the sample is crushed and methane desorption measured again; this measures “residual gas.” If the correction for lost gas can be carried out effectively, the sum of lost, measured and residual gas provides the best estimate of gas content—some operators regard residual gas as nonrecoverable and omit it from the summation.

“Proximate analysis” is then carried out to quantify the four main constituents of coal. The crushed sample, which has already adsorbed its gas, is heated to 105°C [221°F] to determine moisture content. This heat is then boosted to around 950°C [1740°F] to drive off the “volatiles” (organic material, sulfur dioxide and carbon dioxide) leaving “fixed carbon.” The sample is then burned completely and what remains is “ash.” A different set of tests on the core is the “ultimate analysis,” which identifies the elemental weight percents for nitrogen, carbon, hydrogen, oxygen and sulfur.

During its formation, coal is subject to a diagenetic alteration, termed coalification (next page, top right). As organic sedimentary material is converted to coal, gases and liquids evolve. Almost all the physical, chemical and petrophysical properties of coal depend largely on the degree of coalification.

To chart these variables as coal progresses from low-grade to high-grade fuel, the coal

---

### Comparison of Typical Coal Logs to Those from Conventional Reservoirs

<table>
<thead>
<tr>
<th>Property</th>
<th>Dependents on thickness, usually &gt; 10 ohm-m</th>
</tr>
</thead>
<tbody>
<tr>
<td>Density</td>
<td>&lt; 1.75 g/cm³</td>
</tr>
<tr>
<td>Neutron</td>
<td>&gt; 60 p.u.</td>
</tr>
<tr>
<td>Sonic (compressional)</td>
<td>120 ms/ft</td>
</tr>
<tr>
<td>Gamma Ray</td>
<td>&lt; 75 API</td>
</tr>
<tr>
<td>Photoelectric Factor</td>
<td>0.17</td>
</tr>
<tr>
<td>Carbon/Oxygen Ratio from GLT*</td>
<td>&gt; 1.0 relative yield</td>
</tr>
<tr>
<td>Hydrogen from GLT</td>
<td>&gt; .4 relative yield</td>
</tr>
</tbody>
</table>

7. Darcy’s law establishes the flow relationships of gas and liquid phases as they pass through a reservoir.

* Mark of Schlumberger
industry developed a standardized rank table: a higher fixed carbon content corresponds to a higher rank and better fuel.¹ Anthracite ranks highest, followed in descending order by bituminous, subbituminous and lignite (below, right).

Because rank is a function of temperature and time, it increases with depth. A high-rank coal is likely to contain more methane than a shallow, low-rank coal. Early evolution of methane from diagenesis of wood to low-rank lignite is analogous to biogenic evolution of gas as described by organic geochemists. Most of the gas is lost to the atmosphere during the early stages of burial and compaction. However, as bituminous coal becomes anthracite, gas is generated after burial and is less likely to be lost.

With increasing rank, coal produces carbon dioxide and methane and, as it shrinks, loses its capacity to retain water. Coal’s affinity for carbon dioxide is stronger than that for methane, but carbon dioxide is readily soluble in water and therefore its presence decreases as water is lost. Methane tends to become progressively enriched in the coalbed reservoir.

During coalification more methane is generated than can be retained—up to 10,000 ft³/ton of coal. Provided the coal has not been exposed to abnormally low fluid pressures in the geologic past, it should contain close to its methane storage capacity.

There are three ways to rank coal. First, rank can be calculated by relating it to the ratio of fixed carbon versus fixed carbon plus volatiles as determined by proximate analysis. Rank increases with this ratio. Second, rank can be established according to the amount of heat given off when the coal is burned; standard classifications for this exist in many countries. The third type of ranking comes from a reflectance measurement. A polished slide of coal is used to determine the reflectance index, which is directly related to the rank of the coal. This "vitrinite reflectance test" introduces the second important area of coal classification: maceral content.


<table>
<thead>
<tr>
<th>Glass</th>
<th>Group</th>
<th>Rank Criteria Limits of Fixed Carbon or BTU Mineral-Matter-Free Basis</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lignite</td>
<td>Brown Coal</td>
<td>Moist BTU, &lt; 8,300, Moist BTU, &lt; 8,300</td>
</tr>
<tr>
<td>Subbituminous</td>
<td>Subbituminous C coal</td>
<td>Moist BTU, ≥ 8,300 and &lt; 9,500, Moist BTU, ≥ 9,500 and &lt; 11,000, Moist BTU, ≥ 11,000 and &lt; 13,000</td>
</tr>
<tr>
<td>Subbituminous</td>
<td>Subbituminous B coal</td>
<td>Moist BTU, ≥ 8,300 and &lt; 9,500, Moist BTU, ≥ 9,500 and &lt; 11,000, Moist BTU, ≥ 11,000 and &lt; 13,000</td>
</tr>
<tr>
<td>Subbituminous</td>
<td>Subbituminous A coal</td>
<td>Moist BTU, ≥ 8,300 and &lt; 9,500, Moist BTU, ≥ 9,500 and &lt; 11,000, Moist BTU, ≥ 11,000 and &lt; 13,000</td>
</tr>
<tr>
<td>Bituminous</td>
<td>High-volatile B bituminous coal</td>
<td>Moist BTU, ≥ 11,000 and &lt; 13,000, Moist BTU, ≥ 13,000 and &lt; 14,000, Dry FC ≥ 89% and moist BTU ≥ 14,000</td>
</tr>
<tr>
<td>Bituminous</td>
<td>High-volatile A bituminous coal</td>
<td>Moist BTU, ≥ 11,000 and &lt; 13,000, Moist BTU, ≥ 13,000 and &lt; 14,000, Dry FC ≥ 89% and moist BTU ≥ 14,000</td>
</tr>
<tr>
<td>Bituminous</td>
<td>Medium-volatile bituminous coal</td>
<td>Moist BTU, ≥ 11,000 and &lt; 13,000, Moist BTU, ≥ 13,000 and &lt; 14,000, Dry FC ≥ 89% and moist BTU ≥ 14,000</td>
</tr>
<tr>
<td>Bituminous</td>
<td>Low-volatile bituminous coal</td>
<td>Moist BTU, ≥ 11,000 and &lt; 13,000, Moist BTU, ≥ 13,000 and &lt; 14,000, Dry FC ≥ 89% and moist BTU ≥ 14,000</td>
</tr>
<tr>
<td>Anthracite</td>
<td>Semi-anthracite</td>
<td>Dry FC ≥ 86% and &lt; 92%, Dry FC ≥ 92% and &lt; 98%, Dry FC ≥ 98%</td>
</tr>
<tr>
<td>Anthracite</td>
<td>Anthracite</td>
<td>Dry FC ≥ 86% and &lt; 92%, Dry FC ≥ 92% and &lt; 98%, Dry FC ≥ 98%</td>
</tr>
<tr>
<td>Anthracite</td>
<td>Meta-anthracite</td>
<td>Dry FC ≥ 86% and &lt; 92%, Dry FC ≥ 92% and &lt; 98%, Dry FC ≥ 98%</td>
</tr>
</tbody>
</table>

Moist BTU = British Thermal Unit value of coal measured at 30°C [86°F] and relative humidity of 97%. FC = Fixed carbon % determined as follows: dry FC% = % volatile material.

The American Society of Testing and Materials (ASTM) ranking of ash-free coal.

Macerals are the organic microconstituents of coal and vary with source material. There are three main groups: vitrinite originates from the stemmy material in plants; liptinite from leafy material; and inertinite from nonflammable, waxy material (next page, bottom left).

During coalification, large volumes of volatile substances are released. These are relatively rich in hydrogen and oxygen and with time the coal becomes enriched with carbon. The three maceral groups differ substantially in their initial hydrogen/carbon and oxygen/carbon ratios, but by the time coalification is complete, these ratios can be virtually identical. Because macerals can be distinguished visually, they are quantified petrographically by examination of a thin section of a core under a microscope.

If the chemical composition of coal is an important factor in methane production, porosity is a key physical parameter. In porosity, coal differs dramatically from conventional reservoirs. The pore structure of coal can be charac-
terized by the presence of three main pore systems: macropores (diameter greater than 0.1 microns [\(\mu m\)]), transitional pores (0.01 to 0.1 \(\mu m\)) and molecular sized micropores (radius less than 0.01 \(\mu m\)).

Macropores are essentially the cleats, a network of strongly developed, longitudinal (face) cleats and weakly developed, orthogonal (butt) cleats. Spacing between the cleats can vary from fractions of an inch to feet. Microfractures are ubiquitous and inherent in the coalification process, in which the solid volume decreases and fractures.

Coal differs from common sedimentary rocks in having microporosity which makes up about 70 percent of its total porosity. This gives coal its large surface area, on which the majority of methane in the reservoir is adsorbed. Including this molecular porosity, coal has an internal surface area of over \(10^9 \text{ ft}^2/\text{ton}\), and methane molecules can be packed very tightly in monomolecular layers. Gas contents of 500 to 600 \(\text{ft}^3/\text{ton}\) have been recorded in the US for the higher rank bituminous and anthracite coals.

In the past, the rate at which methane is likely to be produced by coal was primarily a safety consideration for the mining industry; now it also governs the viability of coalbed methane wells. The maximum volume of methane that a certain coal can hold at various pressures is determined by carrying out an adsorption isotherm.

At a fixed temperature, a gas-free sample of coal is exposed to methane at gradually increasing pressures. The quantity of methane adsorbed is measured and plotted in standard cubic feet per ton (scf/ton) against pressure. Once the sample reaches equilibrium at initial reservoir pressure, the pressure is decreased and the amount of gas that is desorbed is measured at increments; this is also plotted. The adsorption and desorption data can then be curve-fitted to Langmuir's adsorption isotherm, an equation used to describe the amount of gas adsorbed on a surface as a function of pressure with temperature held constant (above). The isotherm is nonlinear so production rates do not respond linearly to pressure reduction. Indeed, gas flow rate from a coal seam may increase with time. It is not rare for maximum rate to occur months or even years after production starts. Desorption time—the time required to recover 63 percent of the methane from a sample of coal—must also be factored into calculation of production economics.
Log-derived estimate of gas in place at Gas Research Institute well M1, Rock Creek, Alabama, USA. The gas peaks (red on rightmost track) are generated from a relationship established between rank, ash and gas content using core information. The log shows good correlation with the core gas content (pink rectangles).

Analysis, this method of calculating rank can be adapted for log interpretation.

The CNL tool is run in conjunction with the Natural Gamma Ray Spectroscopy (NGS) tool and the Litho-Density tool. The output of these three can be combined to compute ash, volatile material and fixed carbon content, the results of a proximate analysis, and from this rank is inferred. The NGS tool responds primarily to clay which is usually assumed to be the predominant constituent of ash—although in many coals pyrite and quartz can also contribute to ash. The CNL and Litho-Density logs are then used to determine how much of the coal is volatile material and how much is fixed carbon. To achieve this, measurements of potassium, thorium, photoelectric factor, enhanced bulk density and enhanced neutron porosity are combined with known information on the constituents of coal from such sources as SNUMAP (Schlumberger Nuclear Parameter program).

So far, an algorithm used in the Black Warrior basin has been applied to around a dozen cases, and the field-specific model is in the final stages of calibration (left).

Another method of determining gas content uses a more sophisticated logging suite, incorporating either the Geochemical Logging Tool (GLT) or Induced Gamma Ray Spectrometry Tool (GST) measurements. The tools permit elemental composition of the coal to be analyzed. The GLT tool has two modes of gathering data, depending on the timing gate in which the gamma rays are detected. In the capture mode, ten elements can be determined: silicon, calcium, sulfur, iron, hydrogen, aluminum, potassium, chlorine, thorium and uranium. In the inelastic mode, carbon and oxygen are measured.

Carbon, hydrogen, oxygen, nitrogen and sulfur are the chief constituents of coal. As rank increases, the percent carbon increases at the expense of hydrogen and oxygen. In this way, rank can be determined. If GLT measurements are then used in conjunction with NGS, Litho-Density and resistivity logs, an accurate determination of mineral content can be made and used as the ash content, which is subtracted to calculate a pure coal content.

### Gamma Ray, Grain Density, and Density Response

<table>
<thead>
<tr>
<th>GAMMA RAY</th>
<th>Volume Analysis</th>
<th>MACERAL IDENT</th>
<th>COAL FACIES</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.0</td>
<td>0</td>
<td>VITRINITE</td>
<td>NOT DETERMIN</td>
</tr>
<tr>
<td>(GAP)</td>
<td>(PU)</td>
<td>INERTINITE VOLUME</td>
<td>HIGH CLAY VOLUME</td>
</tr>
<tr>
<td>0.50</td>
<td>100,000</td>
<td>LIPTINITE VOLUME</td>
<td>HIGH ASH VOLUME</td>
</tr>
<tr>
<td>(G/C0)</td>
<td></td>
<td></td>
<td>POORLY CLEATED</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>PARTLY CLEATED</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>VERY CLEATED</td>
</tr>
</tbody>
</table>

#### TRACK 1—Gamma ray, grain density, density response
- Response has ash (minerals) contribution subtracted from bulk density measurement.

#### TRACK 2—Volume analysis
- Mineral and rank solution using the Elemental Log Analysis (ELAN) program and inputting GLT, Dual Induction Resistivity (DIL) Log and Litho-Density logs.

#### TRACK 3—Maceral identification
- Maceral solution using the ELAN program, inputting a component for minerals of ash, bulk density log, neutron porosity log, carbon and oxygen.

#### TRACK 4—Gas flow potential
- Determined by the coal cleat logic program.

#### TRACK 5—Coal cleat facies
- From the coal cleat logic program inputting minerals and macerals.

January 1991
Macerals are key organic microconstituents defined by the coal's source material (see “Classifying Coal,” page 31). If coal's total maceral content can be determined, gas content can be estimated, using an empirical equation that relates gas content to maceral content, mineral matter and coal rank. An example of this is the multiple linear regression model derived by Levine in 1987 using a set of 57 coal cores from an exploration well in the Cahaba basin, Alabama. The model indicates that macerals from the inertinite group, while having no significant effect on gas generation, may have a positive influence on gas content.11

Whereas the equation derived by Levine was based on direct determination of coalbed gas content by desorption of cores, this measurement is now being performed based on log measurements. Mineral content, fixed carbon and volatiles are determined using the Elemental Log Analysis (ELAN®) program, which allows the user to adapt interpretation models to the minerals desired and can solve for five different coal models simultaneously. Two passes of ELAN processing are made. The first solves for a generic coal and the mineral content of that coal using all the data available except the inelastic inputs (as measured by the GST tool). The second pass uses the results of the first pass and the inelastic data to determine coal rank.

Rank must be determined to evaluate maceral distribution in coal. Each maceral has a range of properties (like carbon content and density) that varies according to rank (top, right). After elemental analysis is complete, the density, neutron, carbon and oxygen input data are adjusted for the mineral content in the coal—making it dry, ash-free data—and used in a maceral-modeled ELAN computation to solve for the three maceral groups (previous page).

In the San Juan basin, where much of this work was pioneered, details of the types of coals to be encountered and their expected maceral compositions are already well known. In virgin territory, initial assumptions would have to be made and refined using core data.

With a picture of the cleating structure built up, a flow estimate can be made and the mechanical properties of the coal calculated. By comparing cleating in fullbore cores from some 20 San Juan wells, a relationship has been established between maceral and clay content and the extent of cleating. The relative proportion of the three macerals determines the amount of cleating, and the presence of higher clay concentrations reduces cleating. Having established this relationship, relative concentrations of the three macerals determined from the logs can be used to assess the extent of cleating in wells that have not been cored.

Based on the logic that as cleating frequency increases, the permeability of the coal increases and therefore flow rate increases, cleat ratings have been combined with the pore pressure of the coal seam determined by a Repeat Formation Tester (RFT®) tool to produce a flow estimate determination.

Accuracy of log results is highly dependent on mud properties and hole size, drilling damage to the coal at the borehole wall and how much time has elapsed before logging. Coal's friability and low compressive and tensile strengths can have some effect on wellbore stability during drilling. In typical coalbed wells there are few well
control problems and many of the wells are air-drilled; foam and water are also used. However, in some areas of the San Juan basin there are overpressured zones that necessitate the use of weighted mud, which can create invasion problems if the coal is extensively cleated.

The first coalbed methane wells in the San Juan basin were completed openhole. These wells were often underreamed in an effort to remove formation damage that might have occurred during drilling. But most wells experienced difficulties with fines production and fill. Gravel packs were installed but were quickly plugged and had to be removed. In 1985, Meridian Oil Corporation of San Antonio, Texas, USA, operating in the San Juan basin, developed a new completion technique: instead of underreaming, a large cavity is created by unloading the well’s hydrostatic head with air or foam. A preperforated liner can be installed across the enlarged openhole interval.12

Openhole completion certainly involves a lower initial outlay than cementing and perforating, but the potential cost of wellbore instability and coal sloughing could be much greater. As production progresses, coal fines can accumulate in the wellbore restricting future production and possibly requiring cleanup treatment. Cementing offers both support to the wellbore and the option of selective, multizone completion (previous page, middle).

For these reasons, the majority of wells drilled today are completed with cemented casing. Additional hole is drilled below the coal seams to provide space for coal fines to accumulate and for installation of a pump if required for dewatering.

An effective cement bond across the coals requires the usual recommended cementing practices, but coal presents the additional problem of having cleats, which are a clear target for cement invasion. Lightweight, LITEFIL slurries or foamed cement are employed, as are slurries of 50/50 cement/Pozzolan (a light, inert additive commonly used in cement). Lost circulation materials like Kolitex are also incorporated to act as bridging agents and prevent cement from entering the cleats. Kolitex also offers the advantage of further lightening the slurry.

Cemented casing is usually subject to normal perforation. When the stimulation treatment requires a single entry into the formation, notching—using high pressure jets of fluid containing abrasive—is employed to create a single hole, or notch, in the casing. The in-situ permeability can be determined prior to the outset of gas desorption through pressure transient testing (a series of pump-in and falloff tests). At this point, the well is producing only water in single-phase flow. For most of the well’s productive life, however, it is flowing water and methane in two-phase flow. This presents problems for conventional analysis, which assumes single-phase flow.

Testing wells throughout production, rather than just at the beginning, not only charts pressure and wellbore conditions but helps to determine cleat permeability, which may change as reservoir pressure is decreased, thereby creating greater stress in the coal.

As gas and water are withdrawn from a coalbed, the coal undergoes expansion (cleats may contract much like pore space contracts in a conventional well) causing a decrease in permeability. At the same time the coal itself may also contract as the gas is depleted. This increases the size of the cleats and, therefore, increases permeability. It is not clear which process dominates.

A new analysis for multiphase flow transient testing has been developed by ARCO Oil & Gas Co., which enables calculation of a coal seam’s absolute permeability at any time in the well’s production life.13 At the heart of this work is a new pseudo-pressure function that accounts for multiphase flow effects. This analytical method was applied to a well shortly after production had started (where permeability would be little changed from its original value) and good agreement was found with a value calculated immediately after completion using the conventional technique. Skin values (which show the degree of formation damage that has occurred) calculated using both methods also showed agreement.

Positive skin values usually indicate a need for stimulation, namely hydraulic fracturing.14 Removing wellbore damage is just one of four basic reasons for fracturing a well. The treatment should also accelerate dewatering and pressure drawdown, distribute pressure drawdown more evenly to reduce fines production and connect the wellbore to the natural fracture system of the reservoir.

Coal’s effective modulus of elasticity is dramatically different from that of fractured sandstone or carbonate reservoirs. The very low Young’s modulus in coal (107 to 109 psi compared with around 2×1010 to 6×1010 psi in the surrounding rock) makes creation and propping of long fractures difficult.15 In addition, the Poisson’s ratio (used to calculate in-situ stress) of coals is usually greater than for conventional reservoirs and, as previously noted, permeability anisotropy due to the cleat structure often makes fracture direction difficult to predict.

Coal has a complex system of natural orthogonal fractures (the cleats), discontinuities in the bedding planes and in some cases thin coal seams of 1 to 4 feet (30 centimeters [cm] to 1 meter) interspersed with layers of shales, sandstones and dolomites. Together these can lead to multiple fractures, T-shaped fractures and difficulty controlling fracture height.

One research aid, available for coalbeds but not conventional gas reservoirs, is to...


Mark of Dowell Schlumberger
Coal’s Complex Fractures

The design of the fracture treatment depends on the depth, thickness and stratigraphy of the coal seam. Work in the field and theoretical studies divide fracture pressure behavior into four main categories:

**Horizontal fracture**
- At shallow depths where the principal minimum stress is vertical, fractures are generally horizontal. They are created using either limited entry methods (slotting rather than perforating the casing) or mechanical diversion. Linear fluids with moderate-sized pad volumes are preferred. Treatment pressure would be in excess of 1 psi/foot although multiple fracture systems would be created if bottomhole pressure were much larger.

**Vertical fracture**
- A series of thin coal seams at a depth where a single, planar, vertical fracture is favored. This is analogous to a vertical hydraulic fracture in a layered clastic and/or carbonate reservoir. A common practice in stimulating this type of reservoir is to perforate in the clastic zone (sand or silt) adjacent to the coal and allow the fracture to grow vertically. The stress contrast between coal seams is the key element governing fracture growth and can be determined through use of a minifract.
  - This treatment usually allows lower treating pressures (less than 1 psi/foot) than would be required treating the coal exclusively. Leakoff is not usually a problem so normal pad volumes of 30 to 35 percent of the total pumped can be used. To meet the high proppant transport needs, viscous, shear-stable borate crosslinked fluids (or possibly foams) are often employed.

**T and parallel fractures**
- A single, thick coal seam will confine the hydraulic fracture entirely within the coal, and a complex (multiple vertical or T-shaped) fracture system may be created. This usually leads to above normal treatment pressure. High injection rates are needed to combat leakoff as are high viscosity, shear-stable or delayed crosslinked gels and bridging fluid loss additives. Even so, high formation compressibility, the low Young’s modulus of coal and the presence of complex fracture systems mean that a fracture will seldom penetrate more than a few 100 feet [30 meters] from the wellbore.
mine the coalbed after stimulation—called mining back. In this way, researchers have been able to characterize coal's reaction to treatment by actually looking at fractures (below).

Extensive US government-sponsored mining back has been carried out at the Rock Creek research facility. This work confirms the complex nature of induced fractures (see "Coal's Complex Fractures," previous page). Vertical, sand-filled fractures are found to be generally widest nearest the borehole, narrowing rapidly away from the borehole. The maximum lateral extent of sand-filled vertical fracture wings is generally short, usually no more than 300 feet (90 meters).

Mining back confirms the presence of parallel fractures, particularly near the wellbore. The more friable the coalbed, the more prevalent the multiple fractures. Also farther from the borehole, the number of multiple fractures tends to decrease with only a single main fracture remaining.

Parallel fractures are partly responsible for the higher than expected pressures observed in most coalbed treatments which indicate that the fracture has not extended as predicted. Other mechanisms responsible for higher pressures include tip failure, borehole failure and the bridging of proppant and coal particles within the fracture.

The pressure required to propagate a branched fracture with two near-parallel elements has been shown to be about 40 percent higher than the pressure needed to extend a single planar fracture. And, with...
Coal's Complex Fractures

The design of the fracture treatment depends on the depth, thickness and stratigraphy of the coal seam. Work in the field and theoretical studies divide fracture pressure behavior into four main categories:

- **Horizontal fracture**
- **Vertical fracture**
- **T and parallel fractures**
- **T-shaped fractures**

**At shallow depths** where the principal minimum stress is vertical, fractures are generally horizontal. They are created using either limited entry methods (slitting rather than perforating the casing) or mechanical diversion. Liner fluids with moderate-sized pad volumes are preferred. Treatment pressure would be in excess of 1 psi/ft, although multiple fracture systems would be created if bottomhole pressure were much larger.

**A series of thin coal seams at a depth** where a single, planar, vertical fracture is favored. This is analogous to a vertical hydraulic fracture in a layered clastic and/or carbonate reservoir. A common practice in stimulating this type of reservoir is for lateral placement in the clastic zone (sand or silt) adjacent to the coal and allow the fracture to grow vertically. The stress contrast between coal seams is the key element governing fracture growth and can be determined through use of a microfracture treatment. This treatment usually allows lower treating pressures (less than 1 psi/ft) than would be required treating the coal exclusively. Leaktight is not usually a problem so normal pad volumes of 30 to 35 percent of the total pumped can be used. To meet the high proppant transport needs, viscous, shear-stable boreal crosslinked fluids (or possibly foams) are often employed.

**A single, thick coal seam will confine the hydraulic fracture entirely within the coal, and a complex (multiple vertical or T-shaped) fracture system may be created.** This usually leads to above normal treatment pressures. High injection rates are needed to combat leakoff as are high viscosity, shear-stable or delayed crosslinked gels and bridgingfluidless additives. Even so, high formation compressibility, the low Young's modulus of coal and the presence of complex fracture systems mean that a fracture will seldom penetrate more than a few 100 feet (30 meters) from the wellbore.

A fracture, initially confined within a single coal seam, later in the treatment propagates vertically into the bounding layers. If fluid escapes into the boundary layer, the fractures created in the coal may narrow, and screenout may occur if the sand volume is high. To combat this, there must be enough fluid to restart pumping a pad around the vertical component start to propagate. A large pad will widen the fracture to accept proppant before pumping of sand is resumed.

- **Propagating into boundary layer**
  - Fluid escapes into boundary and fracture narrows
  - Time
  - \( W_1 + W_2 \) total fracture volume may be equal

**3.** Oilfield Review  
January 1991

---


a numerical simulator, interaction with natural fractures has also been studied, showing that hydraulic fractures may develop offsets at crosscutting natural fractures.

Coal fines contamination of treatment fluid is also suspected to contribute to abnormal pressures. However, a combination of laboratory and field work indicates that this is not so. Coal fines that are uniformly distributed throughout the fracturing fluid can exist at high concentrations without significantly increasing treating pressure. Fines concentrated at the fracture tip may account for high treating pressure but more than 10 to 15 percent of the fracture must be plugged to explain the observed pressure increase by this mechanism alone. In any case, fines contamination is reduced if treatment is carried out through cemented casing and numerous pump-in and shutdown operations are avoided.

Mining back has also revealed vertical fractures that often do not extend the entire height of the coal beds, although in some cases, fluid or sand proppant (or both) were found penetrating overlying strata.

Where the minimum principal stress is vertical (which usually occurs only at less than 1,000 feet [300 meters]), fractures will preferentially propagate horizontally. Mining back has shown that these are relatively common, mostly at the top of the coal bed at its upper boundary. They are also found along other distinct interfaces such as shale bands in the coal bed.

Some rules of thumb have been developed to help control induced fractures. For instance, the extent of horizontal fractures can be limited by keeping treatment pressures below lithostatic pressure (this may be impossible in shallow seams) and by avoiding perforating at the coal/barrier interface. Proper phasing of perforations can help prevent multiple parallel fractures and, in some cases, notching has been adopted. Use of high-viscosity fluids also helps. And because fracturing pressures appear to increase with coal exposure time, stimulating immediately after completion can help prevent wellbore deterioration.

Lack of the cleats can be controlled using the smallest diameter sand that is practical (often 100 mesh which has a typical diameter of 150 μm). Smaller material is better able to conform to the surface of the coal, blocking potential lack of control areas. This also helps to support the coal and prevent fines production later. Incomplete packing of a fracture and overflushing of the proppant can lead to early fines production. Later, fines may arise from dehydration, shrinkage, and oxidation of the coal.

Use of a Coalbed Methane Agent (CBMA) dewatering aid also assists fines control. During stimulation, this nonionic material is typically added to the fluid used for the pad stages, during which the initial fracture is opened before pumping the main fluid carrying the proppant. The CBMA agent’s surfactant properties increase the relative permeability of the coal to water. Reducing the pressure drop in the reservoir helps keep fines immobile. The tendency for fines to migrate is also reduced by the CBMA dewatering aid maintaining hydrocarbon wetness on the coal’s surface. This is another example of a coalbed requiring the opposite of a traditional hydrocarbon well, where every effort is made to ensure a reservoir is water-wet.

Use of the CBMA additive cuts the amount of water that gets left in the coal (the “irreducible water”), which eventually increases the relative permeability of coal to methane when reservoir pressure is lowest.

Once the water has been produced, its disposal has become a major issue in the US. In part, this has been fueled by the rapid increase in production and the quantity of water produced. As long as total dissolved solids in the water are less than 2,000 parts per million, it can be applied on land (provided this does not cause erosion). Discharge into streams is allowed if chloride concentration remains less than 250 milligrams per liter, otherwise reinjection via disposal wells has to be carried out. Dilution, aeration, and settling ponds are often used to pretreat the water before disposal.

On the positive side, the environmental benefits of clean-burning gas are gaining increased recognition. Future US production is likely to be encouraged now that the Clean Air Act has been passed by Congress. This favors gas over more polluting fuels. Further environmental benefit can be claimed for coalbed methane wells because gas is being burned that might otherwise be released into the atmosphere during venting. While this also adds carbon dioxide into the atmosphere, it removes methane that is thought to be a more serious contributor to the greenhouse effect.