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Get accurate, CBM reservoir data

Unique technology takes advantage of the fundamental geophysics of coalbeds.

AUTHOR

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While conventional tools and analysis methods are used with varying success to describe coalbed methane (CBM) reservoirs, few technologies have been developed specifically to address the key challenges — namely, which seams contain the most gas and how much water must be removed to produce it.

Producers must depressurize a reservoir via water production to desorb gas from coal. Reservoir pressure must be reduced below the effective partial pressure of methane (critical desorption pressure) to allow two-phase flow of gas and water, allowing methane to flow from its adsorbed state in the coal to gas phase and into the well bore.

Because coal seams are relatively continuous and permeable, production-related pressure perturbations in one well bore commonly affect the reservoir surrounding nearby well bores. Therefore, assessment of reservoir producibility and economics must consider the overall field. Conventional wisdom holds that even uneconomic wells contribute to overall field depressurization, and thus to production of gas.

This is based on a tenuous assumption — that the key reservoir properties of gas content and critical desorption pressure are fairly consistent across typical fields, and that "sweet spots" do not exist independent of other parts of typical fields. This assumption is mainly caused by a general lack of data because of high cost and long lead times required for coring and accuracy problems of other methods (mudlogging and gas desorption from cuttings). Because of these constraints, an operator may collect core samples from only one seam in one well per township, while subsequently drilling 100 to 250 wells on each township — sometimes completing them in as many as three seams for each well.

Increasing success for coalbed natural gas requires faster, more accurate and lower cost reservoir data. The WellDog Critical Gas Content reservoir analysis service takes advantage of the fundamental geophysics of coalbeds — most importantly, that the effective partial pressure of methane in the unperturbed reservoir is equivalent throughout the local coal and surrounding water. Partial pressure of methane can thus be measured in one location – such as in wellbore fluid — and be determined for the local reservoir that is accessed by that well bore.

Determining the partial pressure of methane in the wellbore fluid can be done by a number of standard bubblepoint analysis techniques such as headspace analysis of bottomhole samples or water/gas ratio measurements. However, after surveying partial pressure throughout hundreds of well bores, we have found that the effective partial pressure of the fluid in a wellbore can be affected by a number of regularly occurring conditions, including perturbation by production from the surrounding coal, presence of residual solids from the drilling or completion process and con-

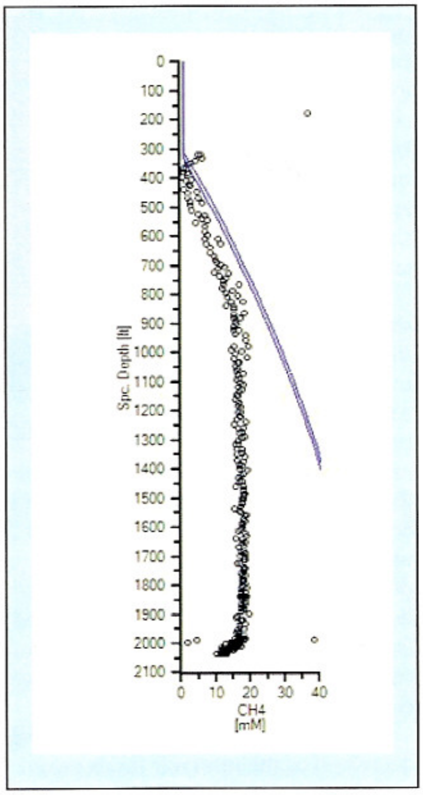

Figure 1. A typical plot of methane solution gas concentration vs. depth was measured in a Powder River basin well bore. (All figures courtesy of Well Dog)

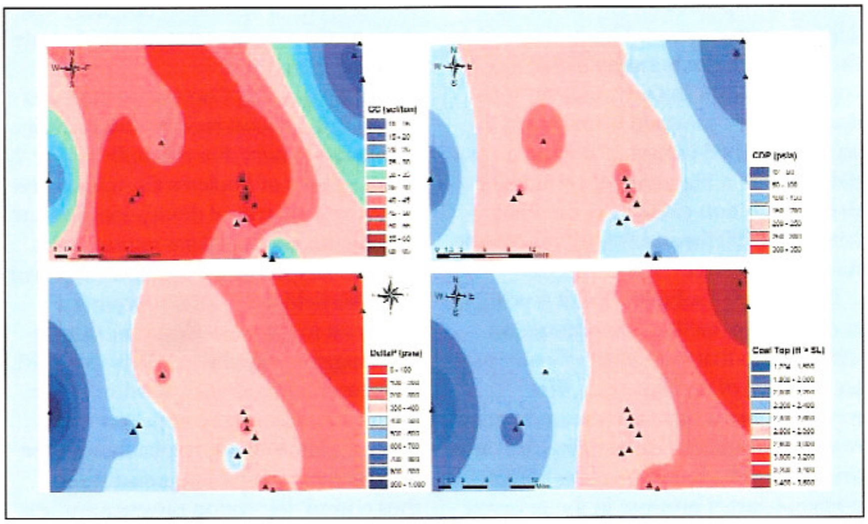

Figure 2. A series of isopleths illustrates how coal structure, critical desorption pressure, gas content and initial gas saturation in the coal vary across a 7 by 5 township area.

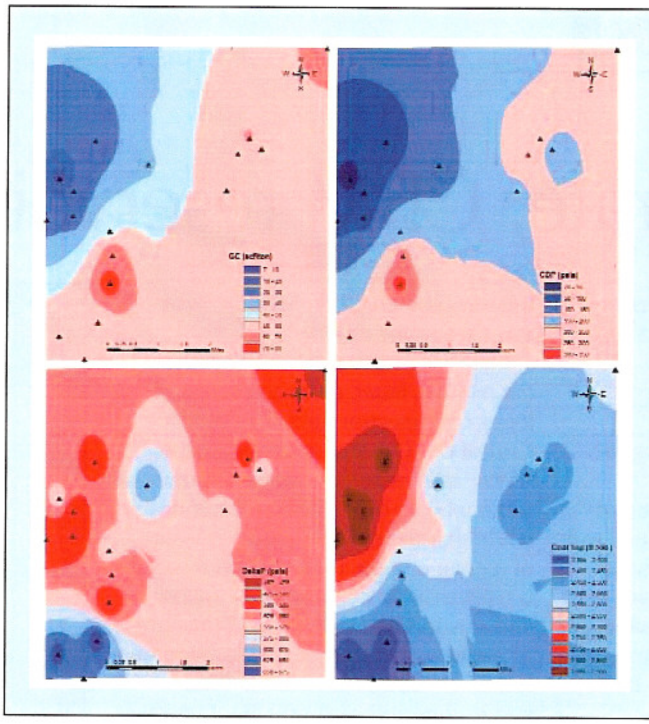

Figure 3. A series of isopleths was generated from data collected in twenty wells distributed across a field measuring about 2.5 miles by 2.5 miles (4 m by 4 m).

tribution of fluids from other completion zones.

Thus, a single measurement of partial pressure at one depth in a well bore cannot be certain to represent the local reservoir. Definitive results can only be obtained by performing continuous measurements, in depth and/or time and comparing the results to well completion and production history.

For example, Figure 1 shows a typical plot of methane solution gas concentration vs. depth measured in a Powder River basin well bore. The completion history of this well bore included perforation at 2,000 fbs (feet below surface), high-rate water stimulation, and blow down to the coal seam prior to the test. Below 2,000 fbs, the well bore contained fresh water. Above 2,000 fbs, the well bore contained fluids drawn in from the target coal seam.

Below 2,000 fbs, the solution gas levels decreased as the reservoir fluids mixed with fresh water. Above about 900 fbs, the solution gas levels decreased as methane cavitated from the water and evolved as gas.

Most importantly, the solution gas levels in fluid at depths between 900 fbs and 2,000 fbs are constant. This indicates that the coal seam surrounding the well bore contains fluids with fairly uniform solution gas levels, as would be expected for an unperturbed reservoir. Together, these data provide a high level of confidence that the solution gas level of the fluid between 2,000 fbs and 900 fbs represents the local reservoir.

By applying a solubility law, it is possible to convert the methane concentration measured in that fluid to an effective partial pressure of methane (i.e., the methane partial pressure required under reservoir conditions to solubilize the measured concentration of methane). This methane partial pressure in the reservoir is related to two key reservoir characteristics: 1) it is equivalent to the pressure at which methane will desorb directly from the coal (and the pressure below which the well begins to produce gas), and 2) it is directly related to the gas content of the coal by a relationship described by a measured methane gas adsorption isotherm for that particular coal.

In this manner, by careful analysis of well completion and production history and by direct measurement of trace levels of solution gas, it is possible to directly and quickly determine critical desorption pressure and gas content of a coal seam. In hundreds of laboratory and field tests, these analyses have returned consistently accurate data.

The Critical Gas Content method provides a fast, low-cost tool for scoping reservoir heterogeneity. For example, Figure 2 shows a series of isopleths illustrating how coal structure, critical desorption pressure, gas content and initial gas saturation in the coal vary across a 7 by 5 township area.

In this field, the coal dips from the northeast to the west. Conventional wisdom suggests that the gas content would be greater in the deeper portion of the seam where the reservoir pressure is greater. However, test results showed the highest methane partial pressure (and thus critical desorption pressure and gas content) in the middle of the field. While the producibility (i.e., the amount of pressure drawdown required to produce gas) was most favorable in the northeast, little or no gas was present in that part of the field. Also, producibility and gas content were both very poor in the deepest part of the field on the west side. Unexpectedly, most of the gas was located in the center of the field, which was also a region with reasonable producibility. Another unexpected result was that the gas content varied widely across this field — from less than 15 scf/ton in the northeast to more than 60 scf/ton in the center of the field. This level of gas content heterogeneity is consistent with results observed in other fields.

To examine reservoir heterogeneity over a smaller field, higher density data sets were collected. Figure 3 shows a similar series of isopleths generated from data collected in twenty wells distributed across a field measuring about 2.5 miles by 2.5 miles (4 m by 4 m).

In this case, the coal showed a general dip from northwest to southeast, with substantial small structures present in the southwest and east. This field is intersected by a river flowing from southwest to northeast. Generally, on the northwest side of that river, gas content and critical desorption pressure were low; on the southeast, both were high. Producibility varied widely, appearing to depend more on individual structures than general field trends. This field included an excellent production target (gas content greater than 60 scf/ton) near the southwest and good production targets (gas contents ranging from 40-60 scf/ton) throughout its eastern half. However, while producibility was good in the northwest, economic quantities of gas were not present in that area, and it is unlikely, given the field structure, that producing wells in that area would significantly impact reservoir pressures in the rest of the field.

Conventional oilfield tools fall short in the complex geology and geophysics of CBM reservoirs. Significant benefits that can be obtained by gathering more complete and accurate reservoir data. E&P