DOWNHOLE GEOCHEMICAL ANALYSIS OF GAS CONTENT AND CRITICAL DESORPTION PRESSURE FOR CARBONACEOUS RESERVOIRS

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ABSTRACT

This paper describes research directed at developing a new downhole analysis method to determine critical desorption pressure and gas content in coals and carbonaceous formations. In this report, we describe the reservoir physics that make the method possible, share laboratory results that illustrate and confirm the underlying physics, and demonstrate the application of the analysis technique in representative field surveys

WellDog's technology uses a Raman-spectroscopy-based sensor capable of detecting and quantifying trace amounts of solution gas. The solution gas level in a coal seam (i.e. the amount of methane dissolved in the coal seam water) is related to the partial pressure of methane via a solubility law such as Henry's Law. Determining the effective partial pressure of methane in a reservoir via a solution gas measurement can provide a convenient and accurate route to determining key reservoir properties like gas content.

Representative field surveys within coal gas development areas show a high degree of variability in gas content not only between coal seams but also geographically for individual coal seams. This high degree of variability underscores the need to collect a large number of gas content values in an areas in order to identify attractive development targets when assessing the gas resource.

INTRODUCTION

The key to successful coal gas development is an understanding of 1) gas content – how much gas is in the coal at current reservoir conditions; 2) saturation-how much gas is in the coal relative to the theoretical amount the gas the coal can hold as measured by an adsorption isotherm; and 3) the critical desorption pressure at which gas an be produced. Until recently, determining critical desorption pressure and gas content for coal seams was difficult, time-consuming and expensive. Generally accepted industry practice has been to retrieve a core sample of the coal, desorb the gas that the coal contains, and relate the resultant gas content to critical desorption pressure, and thus partial pressure, via an adsorption isotherm. This typical analysis is illustrated in Figure 1.
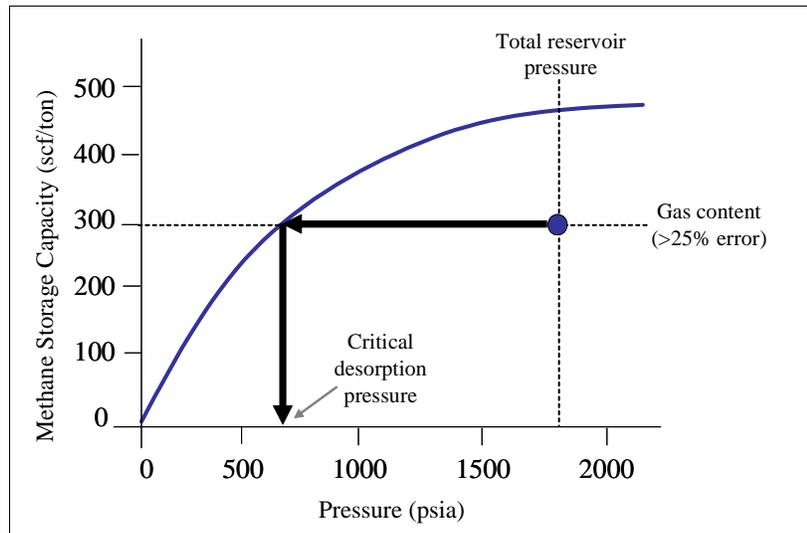
Figure 1. *Standard technique for deriving critical desorption pressure from gas content and adsorption isotherm data.*

The core based adsorption method involves a number of technical challenges and inherent uncertainties, including high expense and risk for core retrieval, difficulties in controlling or measuring "lost gas", a high sensitivity of petrophysical properties to reservoir conditions (e.g. temperature and moisture content), and the weeks to months required to obtain accurate desorption data. As a result of these challenges and uncertainties, many coalbed operators do not pursue detailed reservoir analysis of any kind – but instead rely on anecdotal information and "post-mortem" production analysis to develop a rudimentary picture of the coalbed reservoir and its productivity.

This paper describes research directed at developing a new method to determine critical desorption pressure and gas content. In this report we describe the reservoir physics that makes this method possible, laboratory results that illustrate and confirm the physics, and application of the analysis technique in representative field surveys. Future publications will report in more detail the accuracy of this method, case studies illustrating its practical use, and the results of in-depth laboratory and field petrophysical and reservoir studies using this technology.

The result of this research has been a practical method for analyzing a coalbed reservoir quickly and accurately. This method has been used to describe more than 120 coalbed reservoirs in basins around North America.

BACKGROUND

Natural gas reservoirs are primarily comprised of a storage rock, water and methane (Law, 1994). The amount of methane contained (adsorbed and/or absorbed) in the rock can be represented by an effective partial pressure of methane in the reservoir system

(Nuccio, 1997). This partial pressure then provides a ready quantity from which to describe allocation of methane throughout the reservoir.

For example, the methane gas content of a coal seam is related to the partial pressure of methane via an adsorption isotherm (Figure 2). An adsorption isotherm is a laboratory measurement of how much gas a coal can hold at a given pressure.
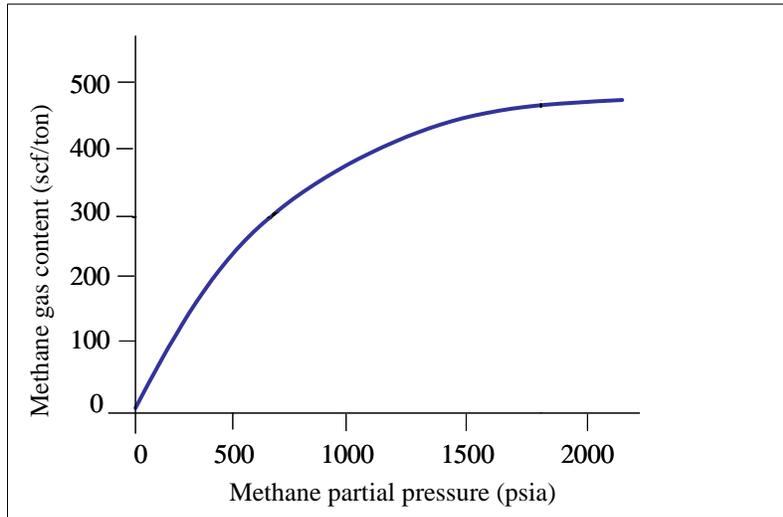

Figure 2. *Typical relationship between methane partial pressure and gas content for coal.*

Likewise, the solution gas level in a coal seam (i.e. the amount of methane dissolved in the coal seam water) is related to the partial pressure of methane via a solubility law such as Henry's Law (Fogg, 1991) (Figure 3).
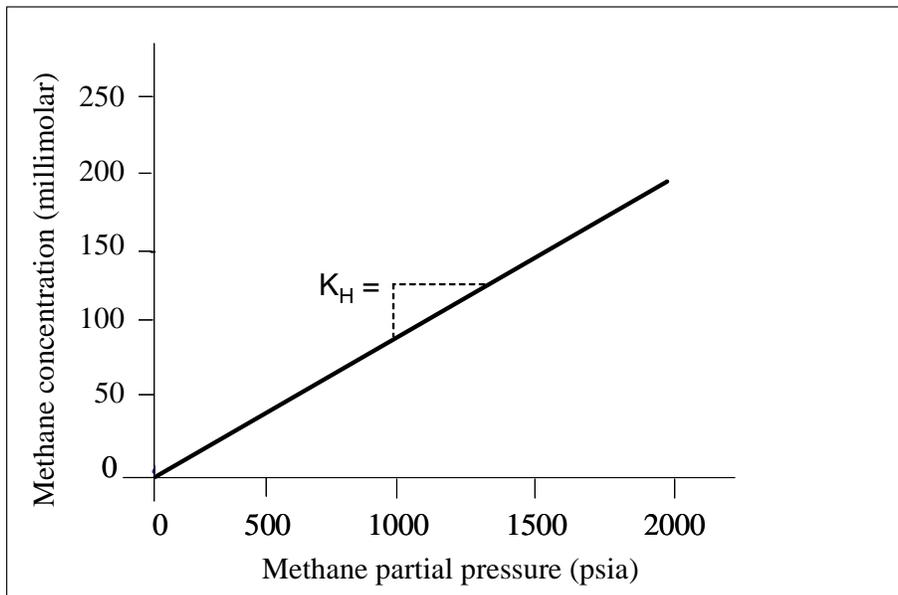
Figure 3. Typical relationship between methane partial pressure and concentration of methane in water under constant environmental conditions. The slope of the line is equivalent to the solubility constant (e.g. Henry's constant, K_H). The slope, and thus solubility constant, varies significantly with temperature, and somewhat with pressure and ionic strength (Fogg, 1991).

The common x axes for the graphs in Figures 2 and 3 provide a connection between the solution gas methane concentration and the coal gas content. As a result, determining the effective partial pressure of methane in a reservoir via a solution gas measurement can provide a convenient and accurate route to determining key reservoir properties like gas content.

In a coal reservoir, the effective partial pressure of methane is equivalent to the critical desorption pressure. That is, the effective partial pressure is the pressure at which the methane partial pressure is equal to the total reservoir pressure and below which gas will desorb from the coal (Barker et al, 2002). In fact, before a reservoir is produced, the methane distribution throughout a coalbed reservoir is in general at thermodynamic equilibrium; as a result, determination of partial pressure at one point results in determination of partial pressure, and the related reservoir characteristics, throughout the reservoir.

As an example of the facility of this partial pressure technique, we can determine the concentration of methane in the water by using a solubility law to calculate a partial pressure and then use that partial pressure, along with an adsorption isotherm, to calculate the gas content of the coal seam itself (Figure 4).
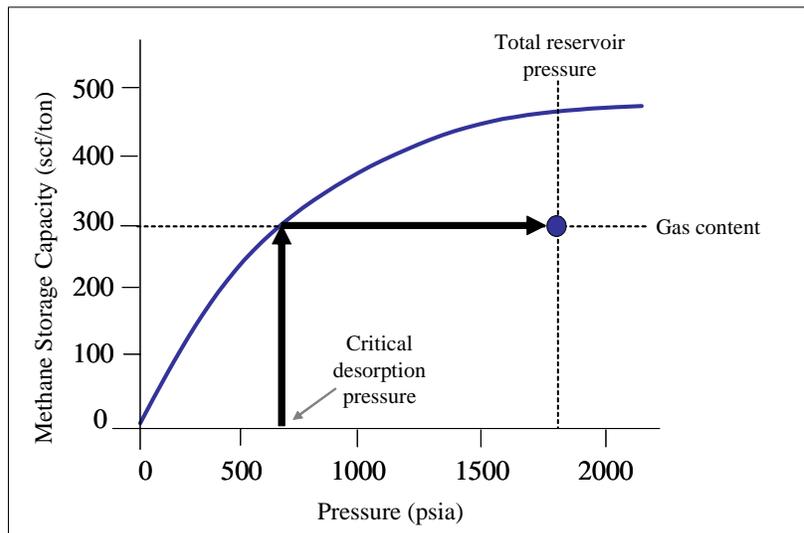

Figure 4. New method for correlating partial pressure, i.e. critical desorption pressure, to gas content using an adsorption isotherm.

RESULTS AND DISCUSSION

It is possible, given modern bottomhole sampling techniques, to retrieve a sample of fluid from a coalbed reservoir and analyze methane concentration (or partial pressure directly) in a laboratory. However, drilling and completion fluids can create complicated downhole environments that require analysis at multiple points in order to be accurately described. As a result, WellDog's research has focused on developing and utilizing a downhole sensor to measure solution gas levels directly.

Few methods are available to determine the concentration of methane in water (i.e. solution gas level) in coalbeds. In fact, only one sensor, based on Raman spectroscopy (McCreery, 2000) and developed as part of this research, is capable of measuring solution gas levels *in situ*.

Laboratory

Figure 5 shows Raman signals typical for methane gas and for methane dissolved in water. As has been reported in the literature (Sloan et al, 1998), the C-H stretching mode for gas phase methane is found at 2917 cm^{-1} while that for methane dissolved in water is observed at 2912 cm^{-1}.
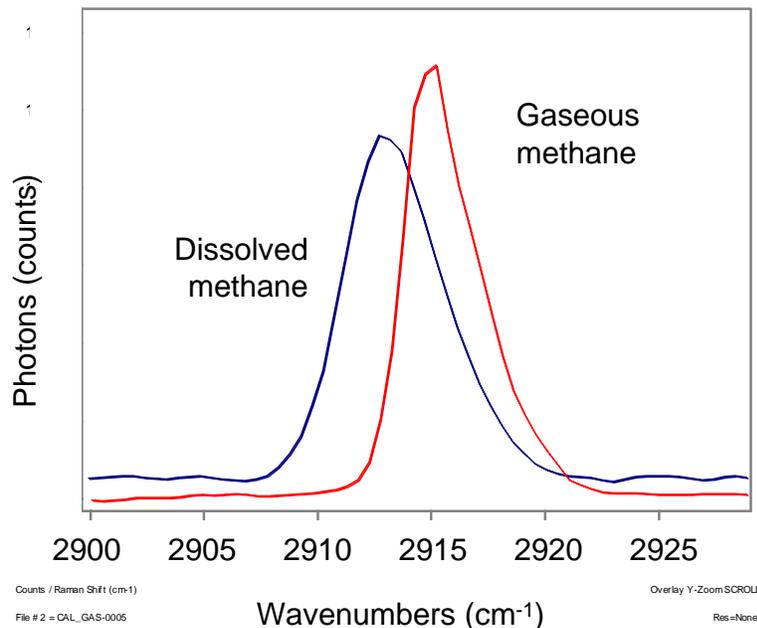

Figure 5. *Raman peaks typical of (left) solution gas and (right) production gas. The x-axis is wavenumber, or energy, and the y-axis is photons collected at each energy. Solvation of the methane molecule by water molecules causes a decrease in wavenumber and slight broadening of the peak.*

Figure 6 shows the relationship between instrument response and methane concentration for WellDog's Raman spectrometer. Instrument response was determined by integrating the peak shown in Figure 5 for samples with increasing concentrations.
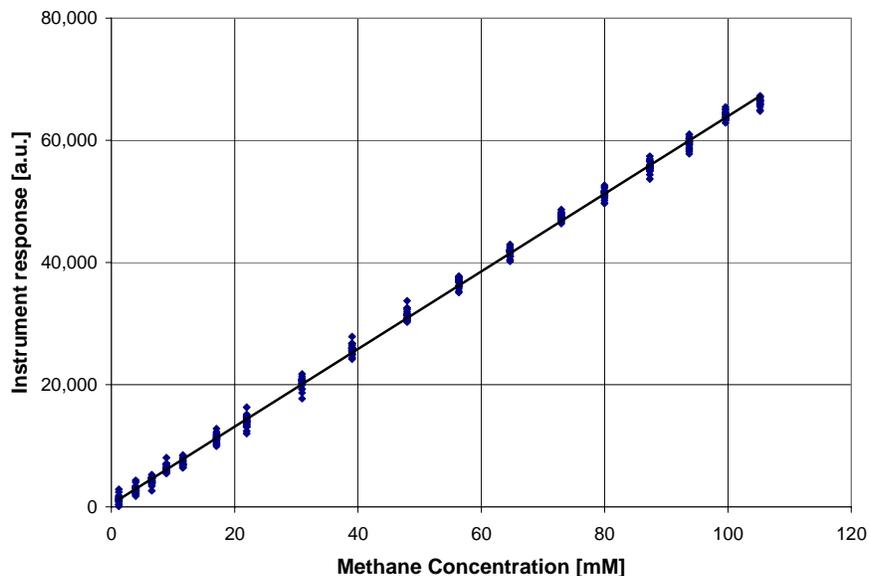

Figure 6. *Photons collected at 2912 cm⁻¹ plotted vs. methane concentration for WellDog's Raman spectrometer.*

In order to convert concentration into partial pressure, we employ Henry's Law (Fogg, 1991) and adjust the solubility constant for reservoir temperature, pressure and ionic strength (i.e. salt content). Using this instrument, then, it is possible to analyze trace amounts (< 50 mM) of solution gas and thereby calculate an accurate partial pressure of methane.

We have carried out these analyses on dozens of simulated coal seams. Coal seams were simulated by inserting a cleaved sample of coal (approximately 1 cm^3 in volume) into a specially prepared pressure cell that was equipped with a high pressure sapphire window, pressurizing the sample cell with methane gas, and then pressurizing the sample cell with water using a water piston assembly. Typically, the systems are allowed to reach equilibrium before analysis.

In order to effect dewatering of a simulated coal seam for some cases, the hydrostatic pressure was gradually reduced while the partial pressure of methane was continuously monitored. Figure 7 shows the results of such an experiment for a sub-bituminous coal pressurized with about 132.6 psi of methane gas and 2,210 psi of water.
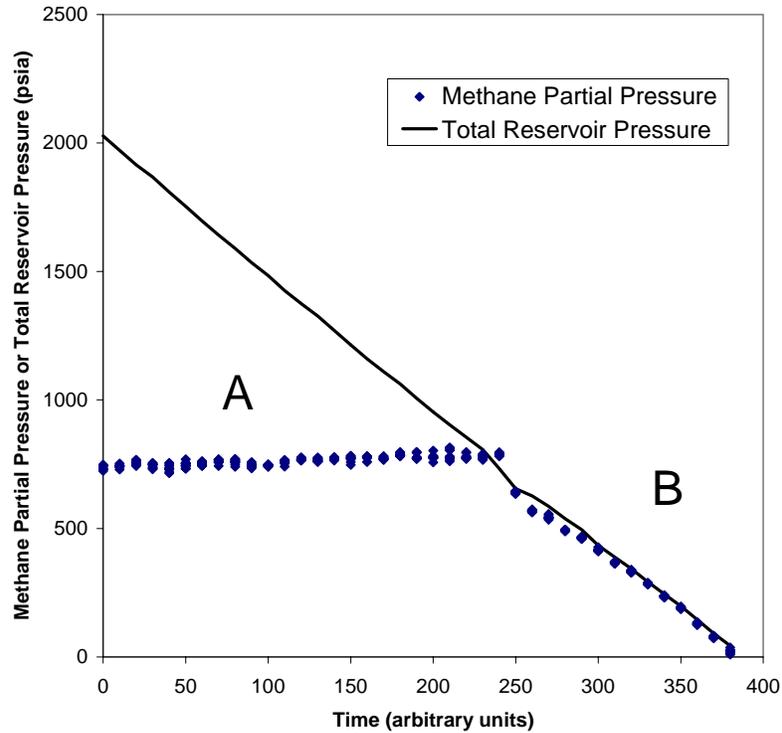
Figure 7. *Partial pressure of methane, measured via a Raman spectrometer, and total pressure, measured via a gauge, for a simulated sub-bituminous coalbed methane reservoir during depressurization of that system. "Dewatering time" is a normalized quantity (the experiment was done step-wise in order to insure equilibrium conditions at each point).*

The partial pressure of methane in the system (again, calculated via measurement of the solution gas concentration and conversion using Henry's Law) after dissolution was 762 psi. That pressure remained effectively constant while the hydrostatic head was reduced, until the hydrostatic head was equivalent to 762 psi. Further reductions in water pressure caused a reduction in methane partial pressure, and substantial production of gas from the system was observed.

In order to verify that the production of gas originated from the coal, and was not merely cavitation of gas from solution, we collected video of the coal/water interface during similar dewatering experiments. Figure 8 shows a representative photomicrograph of that interface under conditions where the total pressure was greater than the partial pressure (region A in Figure 7). At the critical desorption pressure, and for subsequent lower pressures, we observed clear production of gas from the coal sample. A representative photomicrograph of the system under those conditions (region B in Figure 7) is shown in Figure 9.

Figure 8. Representative photomicrograph of a sub-bituminous coal that is undersaturated (i.e. held in region A in Figure 8). Image is 7.2 mm wide.

Figure 9. Representative photomicrograph of a sub-bituminous coal that is producing gas (i.e. held in region B in Figure 8). Image is 7.2 mm wide.

Because the initial partial pressure of methane in that reservoir was accurately measured, it is possible to calculate the initial gas content of the coal sample. Using an adsorption isotherm (Figure 10) in which we have used a Langmuir pressure (half coal gas saturation pressure) of 750 psi and a Langmuir volume (coal gas content at infinite pressure) of 260 scf/ton, we can correlate partial pressure of methane to gas content directly, without the need to collect or desorb gas from the actual coal sample. In this simulated coal seam, then, we calculate a gas content of 127 scf/ton.
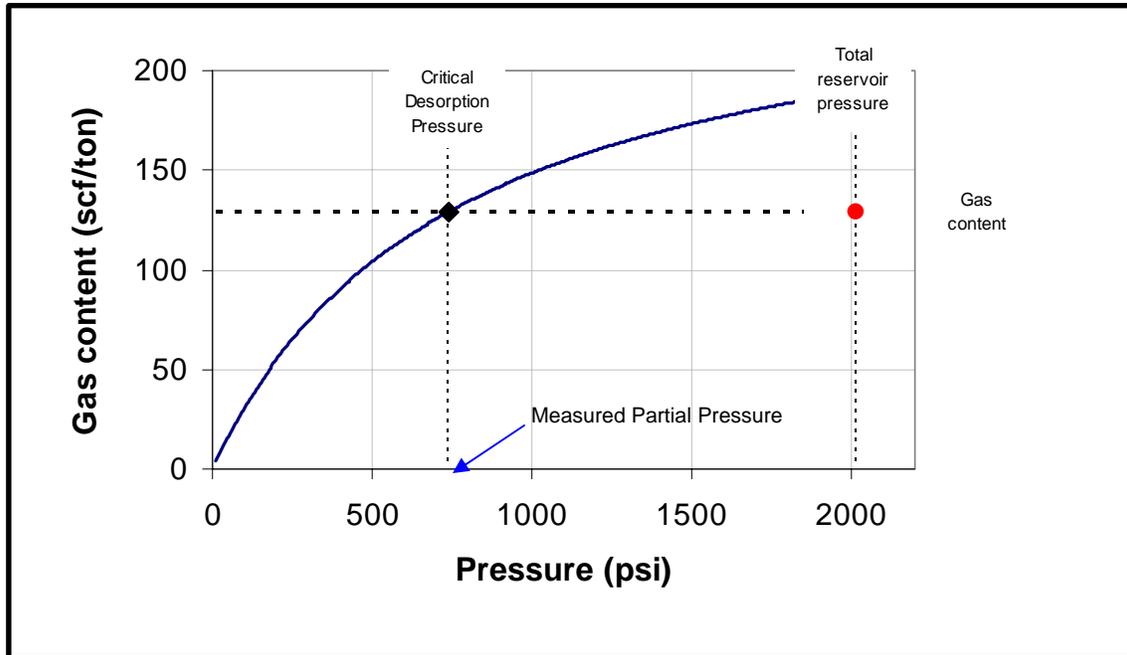
Figure 10. *Graphical representation of using a measured partial pressure and an adsorption isotherm to calculate a gas content value for the simulated coal seam described in the text and illustrated in Figures 7-9.*

Field

In order to perform similar measurements downhole, our group has spent the past five years adapting a laboratory Raman spectrometer to fit into a wireline tool format. The result is a spectrometer that is encased in a housing capable of withstanding 3,250 psi of pressure and that operates readily over standard four-conductor wireline. We have used successive generations of our downhole Raman instrument to analyze more than 120 coalbed reservoirs in the Powder River, Cherokee, and Green River basins of North America. In order to perform those analyses, we have worked with dozens of coalbed operators.

A typical analysis involves review of a well's drilling and completion history and identification of conditions that may interfere with an accurate measurement. Because the measurement is based on analysis of reservoir fluid, situations that compromise that fluid integrity may cause spurious or skewed results. Those situations can include contribution of fluid from other formations (i.e. commingling), residual drilling or completion fluids, suspended particles, or merely skin damage that has impeded reasonable reservoir fluid flow into the wellbore. Our group has developed a number of internal data processing methods that readily correct for low quality fluids (e.g. caused by suspended fines). In addition, nearly all situations where the wellbore does not contain suitable reservoir fluids can be avoided or remedied by careful completion of the well.

Fortunately, these types of fluid issues can be easily diagnosed by simply logging solution gas as a function of depth in a well. For example, Figure 11 shows solution gas logs for a well that contained "city" water (i.e. it was perforated and not stimulated, and showed little or no water production presumably due to skin damage) and for a well that had been stimulated and was capable of flowing substantial water.
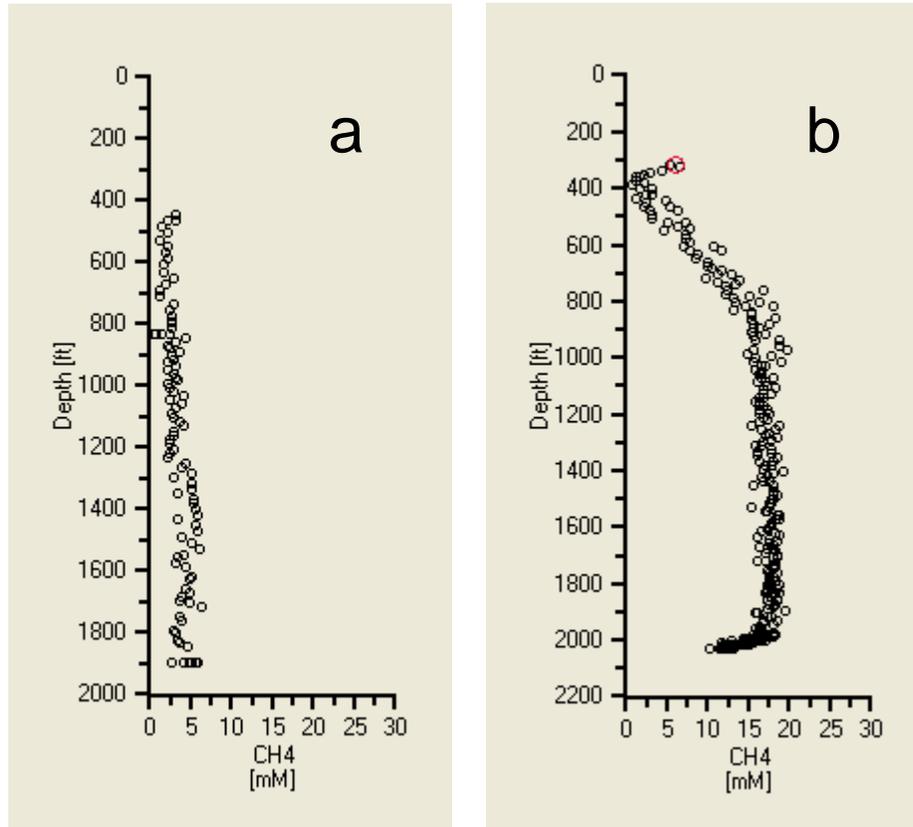

Figure 11. *Log of solution gas in (a) a coalbed methane well that contains "city" water and (b) a coalbed methane well that contains reservoir fluid.*

While the log in Fig. 11a shows essentially no solution gas in the water column, the log in Fig. 11b shows a log profile that is typical for a wellbore that contains homogeneous reservoir fluid down to the perforated zone at 1950 feet. Below that depth, the solution gas level reflects non-reservoir fluid, in this case fresh water, that was resident in the "rathole".

In the log in Fig. 11b, solution gas concentration is constant above the perforated interval up the wellbore until the hydrostatic pressure decreases past the bubble point (above ca. 900 feet). Above that point, the solution gas concentration decreases with the methane solubility limit. Thus, a valid analysis of this well would be to use the reservoir concentrations measured below 900 feet, combined with the temperature, pressure and ionic strength measured at the completion interval, to calculate (via a solubility law) a partial pressure of 230 psi. This value is equivalent to the critical desorption pressure.

In addition, using adsorption isotherm values measured for samples of this coal seam in this region of the field, we have calculated a gas content for this coalbed reservoir of 31 scf/ton. (Note that this gas content does not rely on lost gas analysis.)

Variability in coalbed fields is well known, but perhaps underestimated. Our field survey results do not show homogeneous desorption pressure or gas content values for more than a few wells. A typical field study is shown in Figure 12.
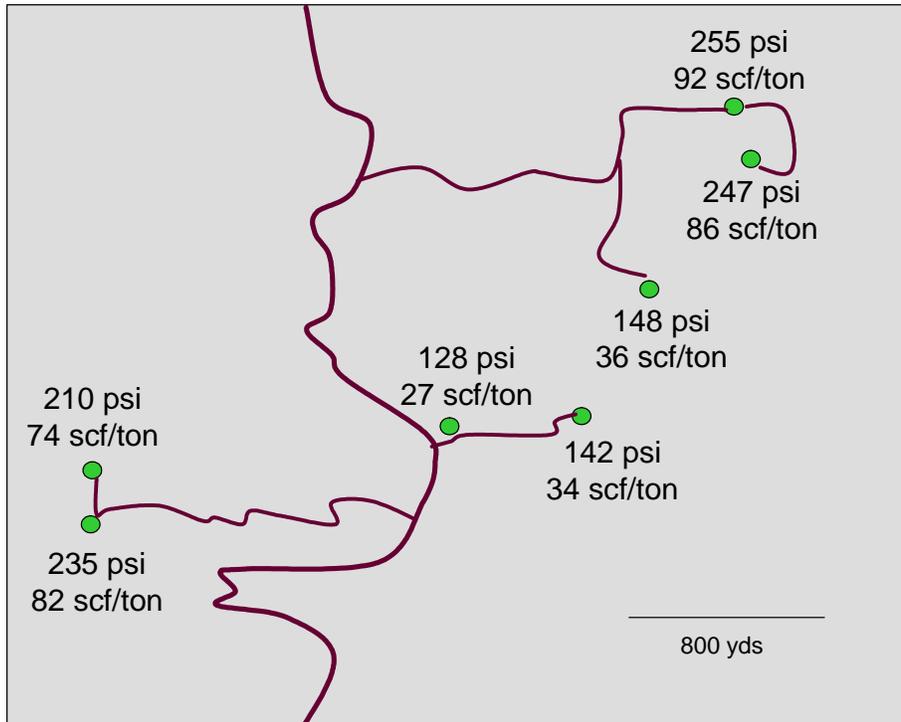

Figure 12. *Results of a field survey of critical desorption pressure (in psi) and gas content (in scf/ton) using WellDog's Raman instrument and Critical Gas Content method. Scale is shown at bottom.*

In this case, seven wells were tested in one seam over a portion of a development area. We observed, across a distance of about two miles, variation of gas content from about 90 scf/ton to ca. 30 scf/ton and back to about 80 scf/ton (from top right, to lower left in Figure 12). We have observed this variability throughout our data set. Figure 13 shows a graph of gas content for 45 well tests performed in six different coal seams over about two years. (Seam names are not disclosed to protect client confidentiality.)
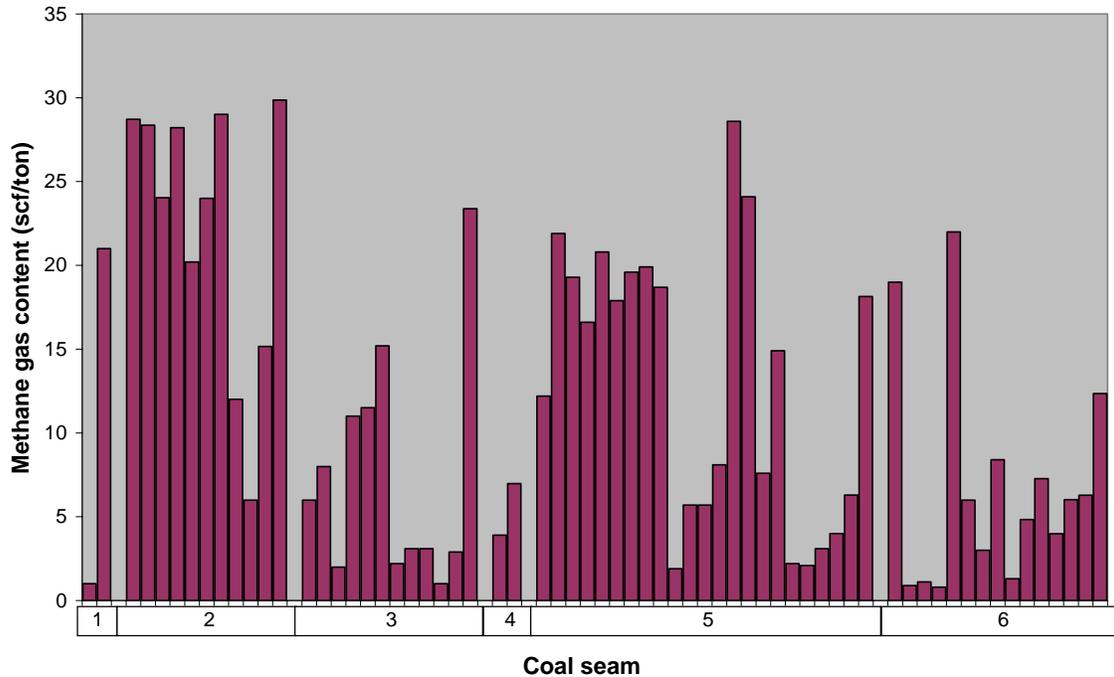
Figure 13. *Results of gas content performed on 45 coalbed reservoirs in six different coal seams in the Powder River basin using WellDog's Raman instrument and Critical Gas Content method.*

This high degree of variability calls into question the value of performing only a few gas content tests per township when attempting to identify attractive development targets when assessing the gas resource.

CONCLUSIONS

WellDog's downhole analysis method is based on development of a Raman-spectroscopy based sensor capable of detecting and quantifying trace amounts of solution gas. The solution gas level in a coal seam (i.e. the amount of methane dissolved in the coal seam water) is related to the partial pressure of methane via a solubility law such as Henry's Law. Determining the effective partial pressure of methane in a reservoir via a solution gas measurement can provide a convenient and accurate route to determining key reservoir properties like gas content.

Representative field surveys within coal gas development areas show a high degree of variability in gas content not only between coal seams but also aerially for individual coal seams. This high degree of variability underscores the need to collect a large number of gas content values in an areas in order to identify attractive development targets when assessing the gas resource.

ACKNOWLEDGEMENTS

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