Low Permeability Gas Reservoirs How Low Can You Go?

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Abstract

Increased focus in tight gas reservoirs has stirred a debate concerning potential uncertainties in determining gas in place and recoverable gas. There are questions concerning the reliability (accuracy and reproducibility) and applicability of routine and special core analysis measurements to the in-situ rock. Small pore volume and the low flow capacity make these rocks particularly sensitive to measurement errors and make it difficult to reproduce in-situ conditions.

A survey of some recent literature provides a glimpse at the state of the art in low permeability core analysis procedures.

Recently, it has been shown that the most commonly used unsteady-state technique over estimates permeability. The differences are most significant for permeability less than 0.01 md. Legacy data for rocks with permeability of less than 0.01 md will be biased high, potentially by up to an order of magnitude.

Multiphase permeability measurements are more difficult to conduct than single phase measurements. Recently published data show a wide variability of permeability reduction with changes in wetting phase saturation. Modeled gas recovery varies by more than 30 percent based on these data.

Differences in irreducible water saturation from capillary pressure curves exist depending on test method. Uncorrected high-pressure mercury injection data often inaccurately characterizes capillary pressures at irreducible water saturation. Typically, higher irreducible water saturations are seen from capillary pressure curves using vapor desorption data and high-speed centrifuge or high-pressure porous plate data in low permeability rocks.

Formation water salinity can show significant variability (+/- an order of magnitude) when reconstructed from a Dean Stark analysis. Water resistivity and saturation in core is difficult to measure in rocks with low total pore volume.

Archie saturation exponent (n) can vary depending on analysis technique. Single point versus multipoint resistivity index measurements and test duration can have a large effect on saturation exponent. These tests can take weeks/months instead of days to become stable.

The prudent evaluation of low permeability rocks worldwide requires the ability to understand and limit these and other sources of petrophysical uncertainty.

Introduction

Unconventional gas reservoirs are a growing part of the total production in the United States (figure 1, EIA, 2006). Low permeability gas reservoirs are by far the largest component and are becoming increasingly important as a global resource.

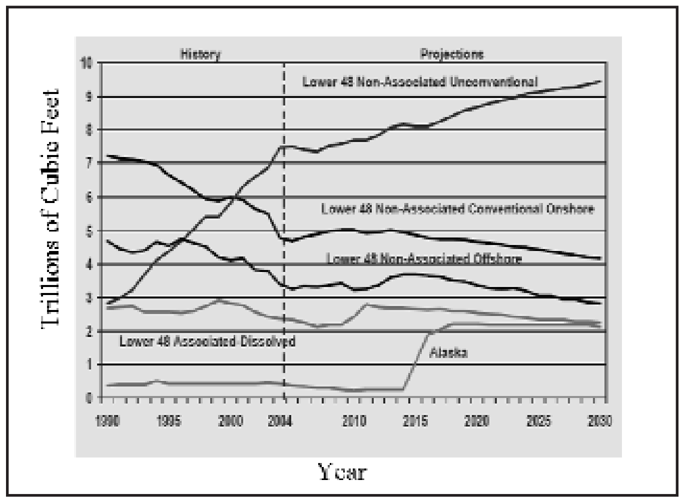

Figure 1. Historic and future trends for natural gas production in the USA.(http://www.eia.doe.gov/oiaf/archive/aeo06/pdf/trend_4.pdf).

A low permeability reservoir rock is defined as having permeability less than 0.1 millidarcies for this study. Most of the porosity in these rocks is split between remaining primary pores and secondary pores created by grain dissolution. Narrow slot like pore throats (figure 2) provide the flow path by connecting the primary and secondary pores (Dutton et al., 1993).

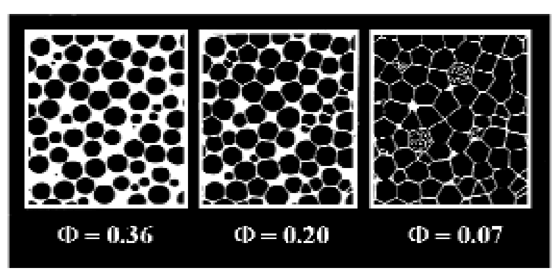

Figure 2. Typical grain and pore arrangement from high primary porosity rocks with relatively uniform pores to low porosity rocks having abundant slot (high aspect ratio) pores (after Roberts and Schwartz, 1985)

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Wireline-log analysis of low permeability gas reservoirs is complicated by numerous factors. These factors include but are not limited to; uncertainty in Archie or shaley sandstone parameters, lack of formation water data, mud filtrate invasion, clay content, and grain density. Reservoir properties are developed using an empirical relationship between the logs and in-situ core analysis measurements (Byrnes and Castle, 2000).

In-situ core analysis data needs to be used as ground truth in these petrophysical analyses instead of ambient pressure data. Questions remain however, about the reliability (accuracy and reproducibility) and applicability of these measurements to the in-situ rock. Small pore volume and the low flow capacity make these rocks particularly sensitive to measurement errors and make it difficult to reproduce in-situ conditions.

The absolute uncertainty may remain high in these rocks, even when great care is used in our analysis technique and methods. Many of these reservoirs have properties at or below the current limit of our ability to accurately measure them.

As the industry moves to exploiting rock of lower and lower quality (gas shales in North America for instance), there needs to be renewed scrutiny of laboratory and wireline quality and results (Al Ruwaili, 2005). Some recent published data for gas shales shows productive intervals with ambient air permeabilites of less than a nano darcy.

Uncertainty of up to 30 percent of recoverable gas will be shown using data from recent tight gas publications and proprietary data. There are potentially issues with both core and wire-line data accuracy and reliability.

A number of questions arise upon closer examination of core data recently presented (Rushing et al, 2004, Newsham et al, 2004 and Laswell et al, 2005) for low permeability rocks:

1≥ Are these rocks amenable to an Archie type analysis or is something else required?

2. Do core analysis standards need to be redefined for low permeability reservoirs?

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3. What is the ability to get these rocks back to in-situ conditions?
4. Are artifacts created in the core as it is handled?
5. What can be done with legacy data, if problems exist with current analysis techniques?

One cannot expect to look at every possible core or log analysis issue relating to low permeability reservoirs. Neither can answers to all of the questions posed above be obtained. However, examples of uncertainty in; porosity, permeability, relative permeability, formation water salinity, core water saturation, capillary pressure and resistivity index, will be presented from some recently published examples and some recent proprietary core analysis.

Porosity

Porosity remains relatively constant even when samples are returned to net overburden conditions in low permeability rocks. A (+/-) 0.2-0.3 porosity unit uncertainty is observed in laboratory analysis techniques. Determining porosity from logs probably has a higher uncertainty than issues related to laboratory techniques.

Helium porosity at in-situ conditions tends to be at 95 percent of the values measured at ambient conditions in reservoir quality low permeability rocks (Byrnes, 1997). This minor response of pore volume is consistent with the idea that slot pores may compress under stress and make up only a minor portion of the overall pore volume. The well-cemented and rigid framework typical of these rocks is also consistent with this premise.

Porosity reproducibility is (+/-) 0.2-0.3 porosity units at stressed conditions as defined in the American Petroleum Institute Recommended Practices for Core Analysis (RP40). This will only result in a minor amount of uncertainty when calibrated with logging tools.

The largest uncertainty in porosity is likely to be the accuracy of the wire-line tools. Accuracy specifications are not well developed in the logging industry (Theys, 1997). Accuracy within 1 porosity unit would not necessarily be considered a problem in an 18 to 22 percent porosity rock. Much higher accuracy is demanded for low permeability reservoirs with porosities between 5 and 10 percent however.

Permeability

Permeability at in-situ conditions can be lowered by more than an order of magnitude compared to values measured at ambient conditions (Byrnes, 1977). The estimate of in-situ single phase permeability from the commonly used unsteady state (USS) permeameter was higher by as much as a factor of two until the error was presented in 2004 (Rushing et al, 2004) and corrected by most of the major laboratories in the U.S.

Routine core analysis permeability data are normally conducted at relatively low pressure (approximately 0300 psia, also called ambient conditions). They are usually single-phase analysis (100% gas saturation, 0% brine saturation). This is typical of our legacy data in North America.

The Klinkenberg (or slippage) corrections are applied to these measurements to account for the difference in gas behavior at the low pressures seen in the laboratory versus the high pressures seen in the subsurface (Bass, 1989). These corrections can reduce routine permeability measurements by as much as a factor of 3 for samples with routine permeabilities less than 1 md (Byrnes, 1997). Permeability measurements that have been adjusted for slippage effects are commonly referred to as equivalent liquid permeability.

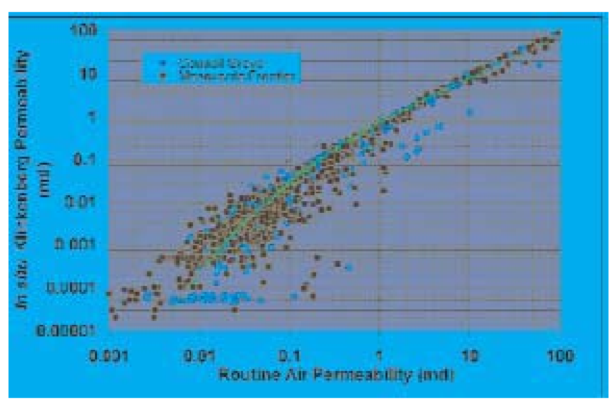

Figure 3. Crossplot of routine air versus in-situ Klinkenberg permeability for Mesaverde-Frontier sandstones (squares) and Council Grove carbonates (circles). Note the increasing influence of confining stress on samples with decreasing permeability. (Byrnes, 2005)

Laboratory permeability measurements are particularly susceptible to increases in overburden stress (figure 3). The greatest response to increasing overburden stress is attributed to rocks with slot pores and pore throats (Davies and Davies, 1999). Pore throats in low-permeability sandstones could decrease by 50 to 70% with increasing overburden stress (Byrnes and Keighin, 1993, reported in Byrnes, 1997).

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Recently it has been reported that the most commonly used unsteady-state (USS) technique consistently over estimates permeability (Rushing, et al, 2004). Permeabilities were compared from the USS permeameter (klinkenberg corrected to equivalent liquid permeability) versus actual liquid permeability in the same samples (figure 4). The differences are most significant for permeability less than 0.01 md. This brings in to question all of the legacy data for low permeability rocks that do not have actual liquid permeability measurements. This analytical error has been corrected in the major laboratories in North America (figure 5). But there is no single "fix" to correct legacy data measured prior to 2005.

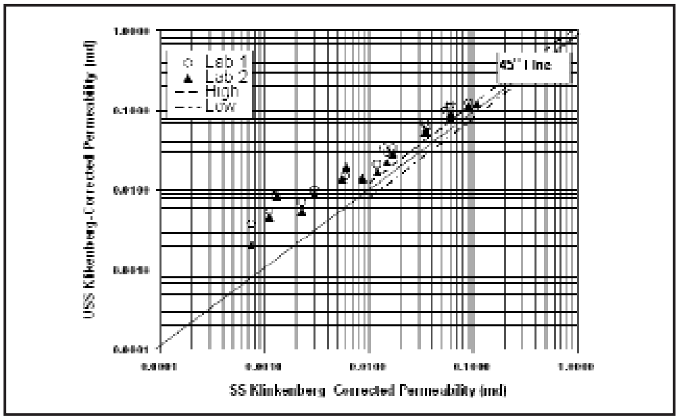

Figure 4. A comparison of steady-state (SS) and unsteady-state (USS) Klinkenberg-corrected permeability (Rushing et al, 2004). High and Low are the analytical confidence intervals from Thomas and Pugh (1998).

Confidence interval, % with probability of:

kg range millidarcys	68.3%	95%	99%
0.01 - 0.1	+/- 8%	+/- 16%	+/- 21%
0.1 - 1.0	8	16	21
1.0 - 50	5	10	13
50 - 1,000	3	6	8

Table 1. Statistically derived confidence intervals of conventional steady-state measurements performed by many laboratories all over the world on a standard set of plugs. (99% confidence interval data from Thomas and Pugh 1989, table from API RP40).

Permeability reproducibility is defined in table 1 from the RP40 (and Thomas and Pugh, 1989). The lowest standard measured in this study was 0.01md and there are only two samples below 0.1md. Most of the rocks currently exploited as tight gas have permeabilities much lower, and the industry continues to try to produce gas from even poorer quality rocks. Some gas shale reservoirs have permeability measured in the nano darcies.

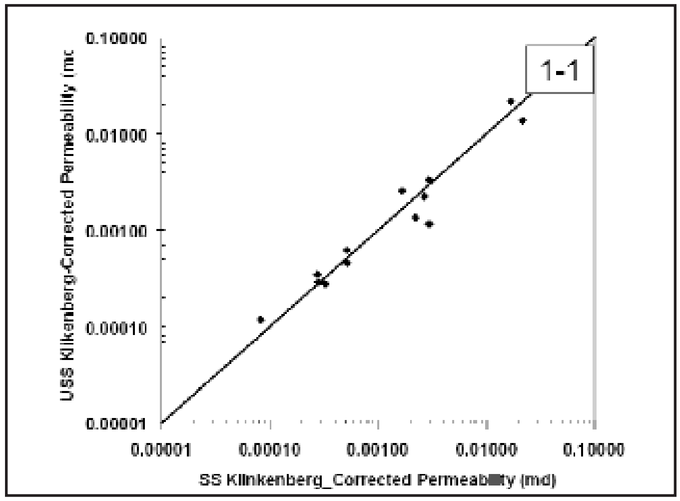

Figure 5. Comparison of steady-state (SS) and unsteady-state (USS) Klinkenberg-corrected permeability for a recently cored low permeability gas well in Wyoming, USA.

It is clear that the effects of increasing overburden pressure are greater than the analysis issues illustrated by Rushing et al (2004). These analytical differences however, could be very significant in rocks with permeability less than 0.01md. These results point out a fundamental flaw in the way the data were being analyzed. This raises additional questions; 1) Do other more complicated measurements also have measurement and/or protocol flaws, 2) Do we need to establish new standards for low permeability rocks?

Relative Gas Permeability

Gas relative permeability at in-situ conditions can be lowered by 3 orders of magnitude compared to single phase values (Shanley et al, 2004). A difference of 30 percent recoverable gas can be modeled from the variability observed in these measurements.

Low-permeability reservoir rocks suffer from the combined effects of overburden stress and partial brine saturation (Shanley et al, 2004; Thomas and Ward, 1972; Byrnes et al. 1979; Jones and Owens, 1980; Dutton et al., 1993; Byrnes, 1997, 2003). Permeability measured in the laboratory at reservoir pressure and saturation, range from 10 to 10,000 times less than routine gas-permeability values measured at ambient conditions. This

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decrease is largely caused by the combined effects of gas slippage (Klinkenberg correction), confining stress, and partial brine saturation and its influence on effective permeability.

Relative permeability is defined as the ratio of the effective permeability of a fluid at a given saturation to the fluid permeability at 100% saturation (Archer and Wall, 1999). There is little consistency in the literature regarding the reference fluid used to determine relative permeability. Care must be taken to ensure that data are reported with consistent reference fluids when comparing legacy data.

Recoverable gas estimates are uncertain when determined from highly variable relative permeability data. It is difficult to measure relative permeability in low permeability rocks due to the stress and saturation issues raised above. It is also difficult to know if there is a uniform saturation along the length of the sample as it is being tested.

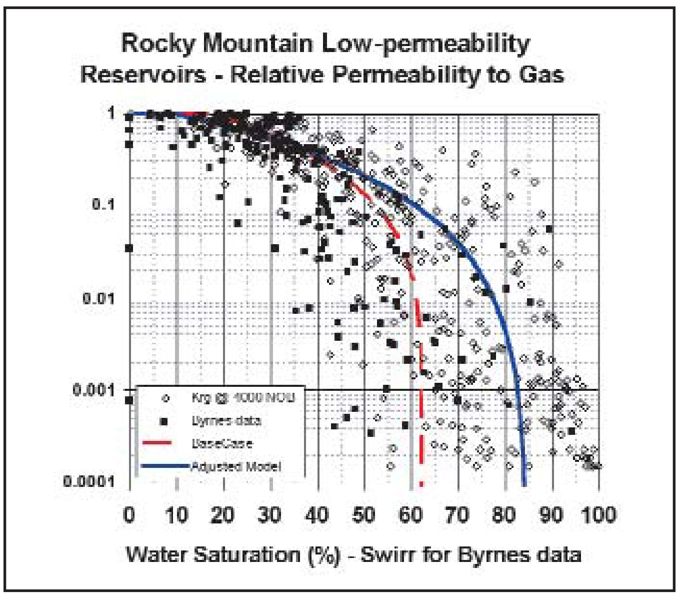

Figure 6. Relative permeability of gas plotted against water saturation. 30 percent difference in recoverable gas is modeled using the functions represented by the "Base Case" and "Upside Case" lines. Data from Shanley et al, 2004.

Relative permeability data from low permeability rocks in the Greater Green River Basin (Wyoming USA) are plotted in figure 6. Reservoir modeling is used to look at the uncertainty associated with recoverable reserves based on the range observed in the relative permeability data. There is 30 percent uncertainty in the calculated recoverable hydrocarbon volumes when the expressions for relative permeability for the base case and the upside case are used in the simulation. Many tight gas reservoirs cover vast areas and this translates into uncertainties of 10's of trillions of cubic feet of recoverable reserves.

Water Resistivity and Core Water Saturation

Formation water salinity can vary by an order of magnitude when reconstructed from a Dean Stark analysis. Water saturation for core is also difficult to determine for low permeability rocks with a low total pore volume.

Water resistivites are determined by extraction from core or measured from produced waters. Core water resistivity is difficult to obtain in low permeability rocks due to their low total pore volume. Often, no water is recovered from core extraction techniques in low permeability rocks. Water salinity values are then determined from recombined total water captured from Dean Stark extraction. Produced water from gas wells cannot be used because they are diluted with water of condensation, and it is difficult to determine the differential volume of condensed water.

For a recombined analysis of water saturation and salinity, the total amount of water is derived from a Dean Stark analysis. The amount of clay bound water is determined from bench top nuclear magnetic resonance (NMR). The amount of imbibed drilling fluid in the core is determined from a tritium tracer added to the mud to tag the drilling fluid. The difference of the total water minus imbibed water minus the bound water equals the in-situ water saturation.

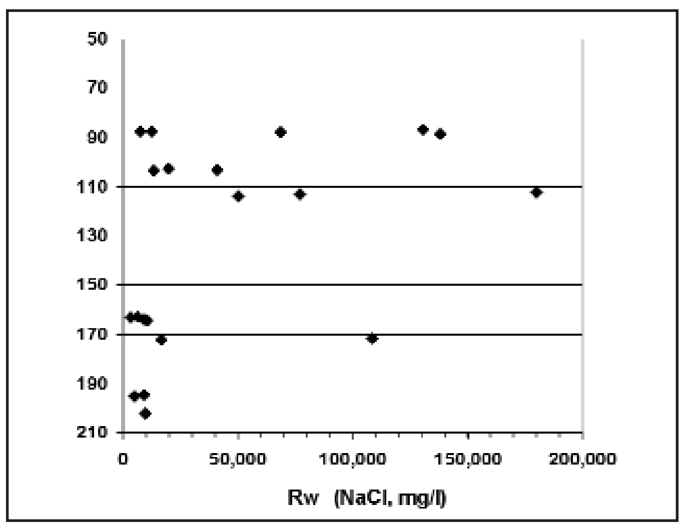

Figure 7. Measured depth below top reservoir plotted against calculated formation water resistivity.

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The water resistivity is then determined from the formation water fraction. The results of this analysis (figure 7) suggest variability in formation water salinity with depth. Notice the high salinity for the shallow part of the section and a salinity decrease lower in the section. Taken at face value, the average formation water salinity can potentially be broken out into at least two gross regions with different average salinities. If valid, the differences in salinity may also suggest that some barrier or baffle exists that keeps these waters from equilibrating.

In this case however, salinity differences can be shown to vary with the volume of formation water extracted from the core (figure 8). Samples with low formation water recovery (less than 0.5cc) have much higher water salinities than samples with higher volumes of formation water recovery. Since Dean Stark extraction has 0.1cc error associated with water volume, the uncertainty in water saturation and formation water salinity will be large if only minor amounts of water are extracted from the core. Applying this data without scrutiny, could lead to errors in both core water saturation and formation water salinity.

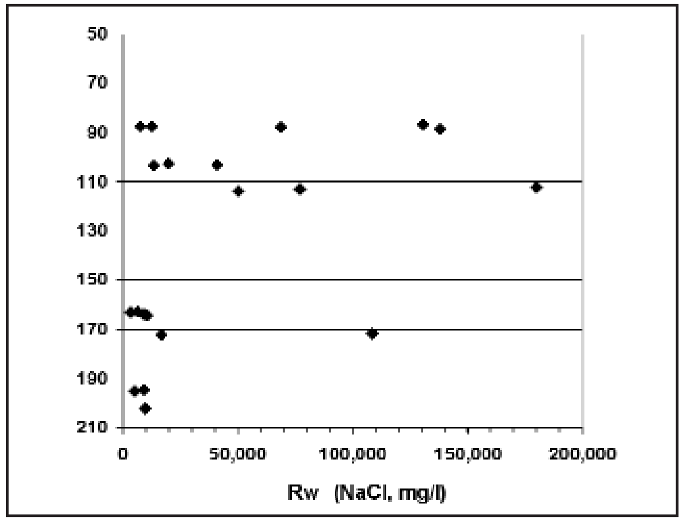

Figure 8. Calculated salinity plotted against the volume of formation water extracted.

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Red Sand Beach Hana, Maui
Photo Courtesy of Mark Pfeifer

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Capillary Pressure and Irreducible Water Saturation

Irreducible water saturations can vary by an order of two depending on the analysis technique. Large uncertainties in calculated gas column height can occur due to errors in determining core water saturations and in irreducible water saturations determined from high pressure mercury injection (HPMI) capillary pressure.

Pore geometry and pore-throat distributions are commonly made using capillary pressure measurements (Yuan and Swanson, 1986; Jennings, 1987; Spencer, 1989; Vavra et al., 1992; Dutton et al., 1993). Pore throats are often less than 0.1 m in diameter (Hartmann and Beaumont, 1999) and capillary pressures are high at relatively moderate wetting-phase saturations in low permeability rocks. Irreducible water saturation is defined as the water saturation at which further increases in capillary pressure produce little to no additional decrease in water saturation.

Irreducible water saturations vary by a factor of two depending on the analysis technique (Newsham et al, 2003). The differences are seen when comparing data on the same rock using both HPMI and centrifuge combined with vapor desorption data (figure 9). Newsham et al, suggest that capillary pressure curves using vapor desorption data and high-speed centrifuge or high-pressure porous plate data appear to provide a more accurate measure for irreducible water saturation in tight rocks.

These differences will affect the calculation of gas in place when calibrated with the logs. Calculated gas column height will also be affected by the differences in irreducible water saturation.

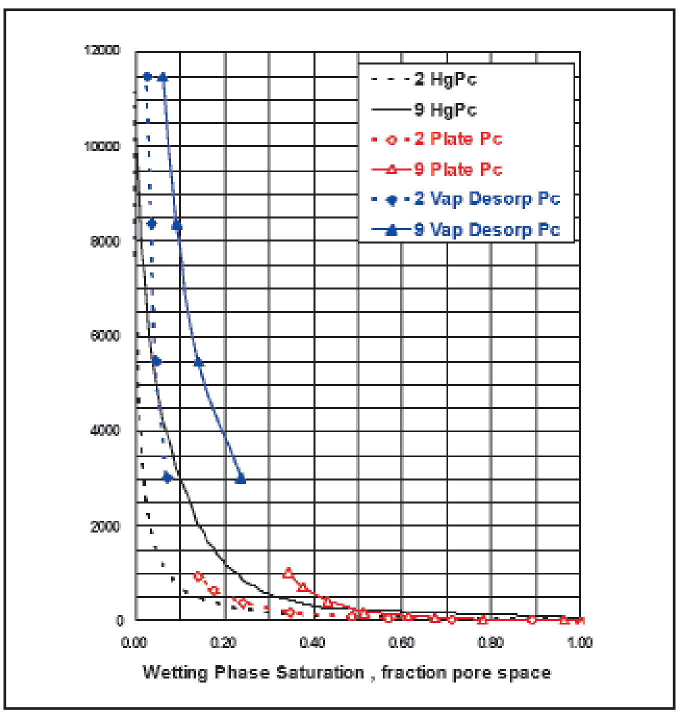

Figure 9. Cartesian plot comparing high pressure mercury injection capillary pressure to composite vapor desorption/high speed centrifuge data. (Data courtesy of Pat Lasswell, OMNI Laboratories).

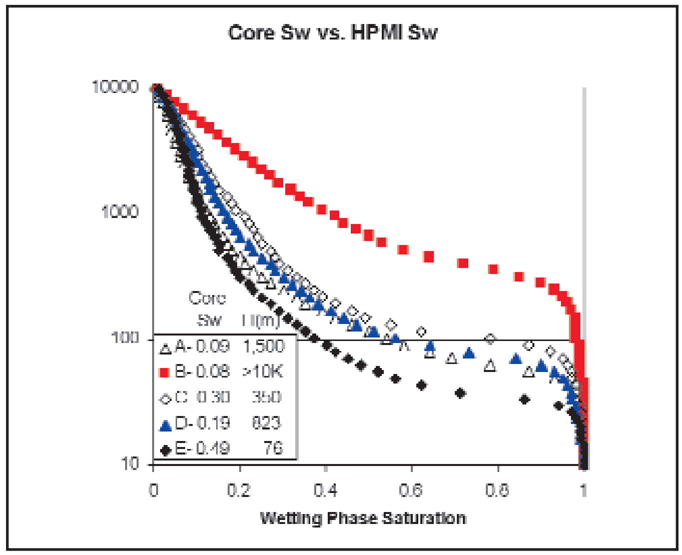

Figure 10. Semi-log plot of height above free water (dry gas) versus wetting phase saturation. All of these plugs are from the same core. The core SW combined with the capillary pressure data, would suggest widely varying gas column heights which is not the case.

A wide variation in potential column height is observed when capillary pressure data and core water saturation are combined in a recently acquired core (figure 10). Column height variations of 2 orders of magnitude are observed when deriving the potential column height using the HPMI data and the water saturations determined from the core. As a comparison, gas-column heights observed in similar rocks range from 300 to 1,000 ft (90 to 300 m) in low-permeability gas reservoirs in the Greater Green River Basin of Wyoming USA (Cluff , 2002) .

The wide variation in potential column height may not however be solely related to the problems associated with the capillary pressure or the core water saturation data. Simple extrapolations of capillary pressure data to hydrocarbon-column heights and saturations could be misleading in basins that have experienced considerable relative uplift and where gas migration and charge commenced before maximum burial was reached (Shanley et al, 2004).

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Saturation Exppoment (*n*)

Differences in the Archie saturation exponent (*n*) can vary by 20 percent depending on rock type and analysis technique. Test apparatus configuration and duration can have a large effect on the determination of these factors. Current thinking is that these tests can take weeks/months instead of days to become stable.

Single point resistivity index (RI) tests are currently being conducted for a joint industry program for North American tight gas reservoirs. The steering committee for the program decided that single point RI tests were the appropriate protocol. Recent studies suggest that this may not be the case.

Laswell et al (2005) looked at the variability of n in a clean and a shaley sandstone (sample 32). This analysis demonstrates the variability seen in this type of data collection. Data was collected using both centrifuge and vapor desorption techniques. The combination of these analytical techniques allows for a wide saturation range for data collection.

There is variability seen in this data related to both the analytical technique and the shale content of the sample (figure 11).

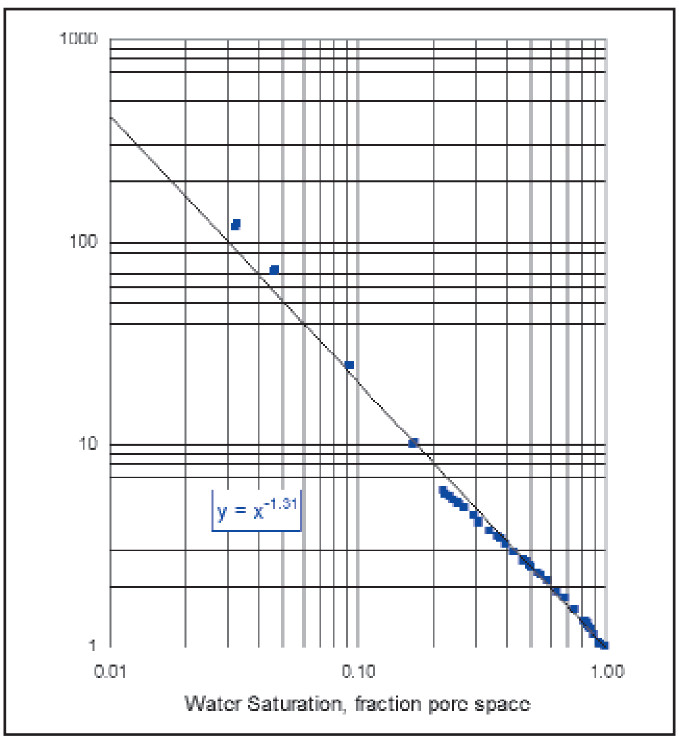

Figure 11. Resistivity Index and capillary pressure data for sample 32 (Laswell et al, 2005).

If only single data point was taken for this sample, what saturation value should be used? What is the variability in saturation exponent based on saturation?

Taken as individual analyses points, an incremental difference of 20 percent in n is observed depending on the final saturation chosen. The n value ranges from 1.58 to 1.17 for this rock. Given that most of our legacy information is single point RI, it is difficult to know how one could use single point RI measurements without a high degree of uncertainty.

Conclusions

The ability to understand and limit the sources of petrophysical uncertainty is vital as low permeability rocks are evaluated world wide. Low permeability rocks are believed to have 50 percent primary and 50 percent secondary porosity connected with slot like pores. This makes them particularly susceptible to the effects of overburden stress and variable water saturation.

Recently published analytical and proprietary core data were investigated in an attempt to identify areas of uncertainty. The following data types were reviewed; 1) porosity, 2) permeability, 3) relative permeability, 4) formation water resistivity, 5) water saturation from core, 6) capillary pressure, and 7) saturation exponent.

Porosity measurements should be conducted at reservoir stress conditions. Porosity is retained at 95 percent of the unstressed values for many of the samples analyzed. Legacy data can be used with a fairly high degree of confidence. The accuracy of logging tools is an area that needs investigation.

Permeability needs to be measured at reservoir stress conditions. Legacy data for permeabilities less than 0.01md will be biased high by some multiple dependent upon the rocks. Legacy data at ambient conditions will also be biased high and could be off by an order of magnitude if permeabilites are less than 0.01md.

Relative permeability is highly variable depending on differential saturations and fluid properties. A 30 percent difference in recoverable gas can be modeled using the variability in the test data set.

Formation water resistivities are very difficult to determine in low permeability rocks. With low pore volume and related water saturation determination uncertainty, water salinities ranged a few orders of magnitude for the well presented.

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Differences of 5 to 10 percent in irreducible water saturations resulted comparing the same samples using HPMI and centrifuge/vapor desorption. These differences will affect gas in place and gas column height assessments.

Differences of 20 percent in Archie saturation exponent (n) are seen on the same sample. Care should be taken in using single point resistivity index analyses especially in shaley sandstones.

Could these uncertainties explain the poor correlation that generally occurs between predictions of low-permeability reservoir behavior based on rock-catalog solutions vs. estimates of reservoir performance based on production logging (e.g., Al-Qarni et al., 2001)?

It remains to be determined how to use the enormous volumes of legacy data given these uncertainties.

Will the prudent evaluation of low permeability rocks worldwide require the ability to understand and limit these and other sources of petrophysical uncertainty, or is the current level of uncertainty acceptable? If the uncertainty level is unacceptable, how much improvement can be gained?

Do these rocks behave like "Archie" rocks, or is there some other approach that should be used? In his 1941 paper, Archie stated; "It should be remembered that the equations given are not precise and represent only approximate relationships. It is believed, however, that under favorable conditions their application falls within useful limits of accuracy". What are the "favorable conditions" and "useful limits of accuracy" in low permeability rocks?

Issues remain with petrophysical lab measurements and their application to subsurface characterization in low permeability reservoirs. The industry needs to understand the uncertainty inherent in the measurements used and work to reduce them or at least make all parties aware of the uncertainty.

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