APPLICATION OF AN INTEGRATED PETROPHYSICAL EVALUATION APPROACH TO NORTH AMERICAN SHALE GAS RESERVOIRS

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ABSTRACT

Unconventional shale gas reservoir development has rapidly increased over the last several years throughout North America. Shale gas wells must be hydraulically fracture stimulated to produce at economic rates and horizontal wells are routinely utilized to maximize well productivity.

Successful formation evaluation of these reservoirs must address petrophysical, geomechanical and geochemical properties of the rock. An integrated petrophysical approach has been developed using multiple logging technologies to: characterize reservoir lithology and mineralogy, porosity, quantify the total organic carbon (TOC) content, calculate a gas in place (GIP) volume, identify and characterize fractures and describe the total reservoir stress regime and rock mechanical properties. A methodology has also been developed using geochemical measurements to identify lithofacies within the shale reservoir. By incorporating geomechanical analyses with lithofacies determination the intervals that are the most preferable for fracture initiation as well as those most unfavorable can be identified. These results are designed to allow an operator to select the optimum horizontal lateral location and identify the preferred lithofacies for fracture initiation.

This paper is intended to provide an overview of the usage of the technologies in the integrated approach; which include resistivity, density, neutron, cross dipole acoustic, magnetic resonance, acoustic and resistivity imaging, mineral spectroscopy, spectral gamma ray and core analyses. The references cited provide detailed descriptions and explanations of the methodology developed and used in specific North American shale plays. Examples from some of the well known North American shale plays illustrate the use of this integrated approach.

INTRODUCTION

Shale gas reservoirs have over the last three to five years emerged as the most active exploration and development plays in North America. Figure 1 illustrates the geographic locations of shale basins in the US. While many of these basins have had only limited exploration, significant exploration and production activity is taking place in the Marcellus, Haynesville, Woodford, Fayetteville, and Barnett Shales. Exploration is occurring at a rapid pace. The map in Figure 1 was published in April 2009 but one of the newest plays is not even on it; the Eagleford Shale in South Texas. In addition to these US shale plays the Horn River Shale and Montney Shale plays in western Canada are also very active.

Organic shales have not always been a significant exploration target. The first shale gas production in the US took place in 1821 when a well was drilled to a depth of 70 feet into the Upper Devonian Dunkirk shale in Fredonia, New York (Ref. 1). However, it was not until two significant technological innovations were introduced in the Barnett Shale play by Mitchell Energy (purchased by Devon in 2002) that extensive exploration and development of shale reservoirs across North America began in earnest. Both of these innovations resulted in larger well gas productivities. In 1997 Mitchell began using slickwater hydraulic fracturing in the Barnett Shale. That technique was able to effectively fracture a much larger volume of rock than the previous approaches at a reduced cost. In 2002 Devon began experimenting with horizontal wells, drilling 9 that year. By late 2003 to early 2004 horizontal drilling was being used by many Barnett...
Shale operators. The technique often more than doubled well productivities.

By the end of 2007 gas production from all unconventional reservoirs provided 48% of the total US gas production. Projections indicate that by 2020 they will be providing roughly 69% of the total production (Ref.2.). As indicated in Figure 2, the biggest contribution to this increase is expected to come from shale gas reservoirs.

Numerous industry, government and academic researchers have conducted studies in several shale basins to determine the geochemical, geologic, petrophysical and geomechanical characteristics of each shale gas reservoir. An additional goal of these studies was to identify the critical formation evaluation parameters that must be quantified in order to determine if a specific shale well or play will be commercial. Examining this collective research showed that while each shale play is unique they share some common characteristics. Shale gas reservoirs can generally be described as dark grey to black organic shales with a kerogen (TOC) content greater than 1% (usually much higher). These reservoirs serve as both the source of the gas as well as the reservoir rock. Gas is present both as free gas in the shale as well as adsorbed gas associated with the kerogen. Natural fractures play a role in productivity of these reservoirs but their relative importance varies from basin to basin. Often based on our experience with conventional reservoirs, we tend to expect a shale lithology to be rock having a high clay content. Shale can also be defined as a fine grained sedimentary rock composed of clay sized material. Generally, the shale gas reservoirs in North America meet the second definition. They are not composed primarily by clay minerals but rather mixtures of clay to silt sized fractions of many minerals including quartz, feldspars, calcite, dolomite, siderite, clays, pyrite and organic matter (kerogen) (Figure 3).

One of the most significant shared characteristics of shale gas reservoirs is that they must be hydraulically fracture stimulated in order to produce at economic rates. Increasingly these reservoirs are being developed using horizontal laterals. Using conventional petrophysical evaluation methods it is difficult to predict the success of a stimulation or completion strategy. Operators need an approach which will assist them in maximizing well productivity by designing and implementing an effective stimulation program and optimizing the location and orientation of the horizontal lateral in the reservoir section (Ref. 5.).

DESCRIPTION OF THE INTEGRATED PETROPHYSICAL APPROACH

Over a three year period an integrated approach was developed which utilizes a variety of wireline, and or LWD, technologies including resistivity, density, neutron, cross dipole acoustic, nuclear magnetism, acoustic and resistivity imaging, mineral spectroscopy, spectral gamma ray and core analyses (Ref.5.). The methodology has been successfully utilized by operators in several different North American shale plays including the Barnett Shale (Ref.5, Ref.6), the Haynesville Shale (Ref.6, Ref.7), the Woodford Shale (Ref. 8) the Marcellus Shale and the Eagleford Shale. Figure 4 illustrates the technologies utilized and the evaluation objectives each technology addresses.

LITHOLOGY & MINERALOGY

The primary technology in the determination of lithology and mineralogy utilized by the integrated approach consists of a combination of a pulsed neutron and a natural gamma ray spectroscopy tools. These geochemical instruments investigate the inelastic, capture and natural gamma ray energy spectra to obtain elemental yields and weight fractions of various elements including Al, C, Ca, Fe, Gd, K, Mg, S, Si, Th, Ti and U. Lithology and mineralogy are then determined by an expert system which uses the elemental weight fractions from the geochemical measurements as input. (Ref. 9, Ref. 10). Currently eighteen minerals are quantified: illite, smectite, kaolinite, chlorite, glauconite, apatite, zeolites, halite, anhydrite, hematite, pyrite, siderite, dolomite, calcite, K-feldspar, plagioclase, quartz and organic carbon, which is identified either as kerogen, coal, or oil (Ref. 8, Ref. 10).

Analysis of actual rock samples can provide independent verification of the interpreted mineral composition. Both X-Ray diffraction analyses, which measure the amount of specific minerals in a rock sample and X-Ray fluorescence analyses which measure the amount of specific elements in a rock sample are routinely obtained. Because of the significant difference in the scale of the core analyses measurements and the volume of rock measured by the pulsed neutron and spectral gamma ray devices we do not “calibrate” or force fit the interpreted results to these analyses. Instead the analyses are used in a comparative manner to confirm that the suite of minerals as well as the relative amounts of each mineral calculated from the logging measurements are consistent with those measured from the rock samples.
If discrepancies occur they are investigated and the logging tool responses, processing methodology and borehole environmental parameters and mud chemistry information are all re-examined. Figure 5 shows a comparison of XRD and XRF analyses to the pulsed neutron measured elemental weights and computed mineral composition for a sandstone reservoir (Ref. 9).

Various researchers conducted detailed geologic and mineralogic studies utilizing wireline log data, detailed geologic description and extensive core analyses from whole core for individual shale gas reservoirs. They identified lithofacies which are characterized by differences in mineral composition, the amount of kerogen present, depositional environment and changes in the mechanical properties of the shale such as brittleness or ductility of the rock. As shale gas reservoirs must be hydraulically fractured to produce economically, identifying the lithofacies which are most favorable for gas production and fracture initiation and discriminating the most unfavorable lithofacies is critical for maximizing well productivity. In several of the shale plays studied the most favorable lithofacies was identified as a siliceous mudstone, characterized by higher amounts of quartz which increased the brittleness of the rock (Ref. 5, Ref. 7 and Ref. 8).

Using only the chemistry and mineralogic results obtained from the pulsed neutron and spectral gamma ray tools we were able to identify lithofacies in shale gas reservoirs for use in the integrated petrophysical model (Ref. 5, Ref. 7, Ref. 8 and Ref. 10). It should be kept in mind however that there is no “typical” shale gas reservoir mineralogy that is representative for all plays and that the mechanical properties of a specific lithofacies might be quite different between one shale gas play and another. Figure 6 compares mineral composition from four of the active US plays, the Barnett Shale, Marcellus Shale, Eagleford Shale and the Haynesville Shale (Each vertical division on the plots is an incremental 10% weight fraction of the total matrix).

Observations: The Barnett Shale section has a much higher percentage quartz content (50-70%) than the other shales, while the Eagleford Shale has the highest carbonate content (40-60%). The predominant clay type in all these plays is illite/mixed layers although the Marcellus Shale also has a 5-20% smectite component. Examining the carbonates in the Marcellus Shale we see more dolomite than in the other examples. The Marcellus Shale also exhibits a more consistent pyrite component.

**TOC DETERMINATION**

Increases in the amount of TOC present in a shale gas well generally result in increased gas in place as adsorbed gas is contained in the kerogen present in the reservoir. Likewise increased well productivity also generally correlates to increases in the net thickness of the organic shale (Ref. 5). Several methods to determine the amount of TOC present have been developed by the industry using empirical relationships to various conventional log responses such as resistivity, bulk density and total gamma ray. However the accuracy of these empirical approaches is often reduced by the variable mineralogy present within a shale reservoir (Ref. 5, Ref. 10). The integrated petrophysical approach provides two independent measurements of TOC (Ref. 5, Ref. 8). A direct measurement of TOC is obtained from the elemental carbon weight fraction measured in the inelastic gamma ray energy spectrum by the pulsed neutron mineral spectroscopy tool. The amount of the measured carbon which is associated with the organic material is calculated by subtracting the amount of carbon required as a component of the inorganic minerals determined by the expert system.

\[
C_{TOC} = C_{total \ measured} - C_{Calcite \ computed} - C_{Dolomite \ computed} - C_{Siderite \ computed}
\]

A second TOC calculation is made using NMR porosity and fluid density measurements, the bulk density and the expert system (mineralogic) derived inorganic matrix density. The calculation is as follows:

\[
\rho_{gr} = \frac{\rho_b - \rho_{fluid} \phi}{(1 - \phi)}
\]

\[
V_{TOC} = \frac{\rho_m - \rho_{gr}}{\rho_m - \rho_{TOC}}
\]

\[
m_{TOC} = \frac{\rho_{TOC} \cdot \rho_m - \rho_{gr}}{\rho_{gr} \cdot \rho_m - \rho_{TOC}}
\]

Where

- \( \rho_p \) is the bulk density
- \( \rho_{gr} \) is the total grain density including inorganic and organic matrix constituents
- \( \phi \) is the NMR total porosity
- \( \rho_{fluid} \) is the density of pore filling fluid, determined from NMR fluid typing
- \( V_{TOC} \) is the volume fraction of organic matrix components
- \( m_{TOC} \) is the mass fraction of organic matrix components
Porosity and GIP Calculation

Typical shale gas reservoir porosities are low, often in the range of 3 to 6%. Porosity calculations from neutron and density measurements may have significant uncertainties due to the variable mineralogies and the variable amounts of low density organic material present in these reservoirs. In the integrated petrophysical approach porosity is preferably derived from the NMR, which is not affected by lithologic or mineralogic variations. Comparison of NMR total porosities to core porosities in several shale plays has shown good agreement (Ref. 8).

The gas-in-place determination in shale gas reservoirs has two components, the free gas calculation and the adsorbed gas calculation. In the thermogenic shale gas reservoirs we have studied the free gas component is felt to be the most significant. This may not be the case in biogenic shale gas reservoirs. The free gas calculation is made using a conventional Archie petrophysical methodology; calculating water saturation from measured resistivities with porosity derived from the NMR device. Figure 7 shows the comparison of this technique to core measured porosity and water saturations for two wells in the Woodford Shale (Ref. 8).

GEOLOGIC CHARACTERIZATION

Most shale gas reservoirs have some degree of natural fractures. Borehole imaging devices are utilized to characterize the natural fracture networks, identifying their orientation, determining if the fractures are open or mineralized and discriminating between natural and drilling induced fracturing. Major structural elements such as faulting and unconformities must also be located in order to evaluate the risk of water influx from underlying formations after hydraulic fracturing.

GEOMECHANICAL ANALYSES

Detailed geomechanical analyses are required in order to maximize well productivity in shale gas reservoirs. Complete characterization of the in-situ stress magnitudes and orientations is necessary to design effective hydraulic fracturing and horizontal well orientation strategies. In addition there are significant differences in the mechanical properties of shale lithofacies that are related to changing mineral composition and amounts of organic material present. In order to optimize the hydraulic fracturing effectiveness the most favorable intervals to initiate fractures must be identified. In the integrated petrophysical approach in-situ geomechanical rock properties are computed by integrating geochemistry, mineralogy, NMR, density and acoustic analyses.

Shale gas reservoir researchers had determined that differences in the mechanical properties of the shale resulted from differences in the mineral composition. In addition to the derivation of the “standard” dynamic mechanical constants the integrated petrophysical approach constructs a rock model based on the variations in the mineralogy, TOC content and NMR porosity. This model is then used in conjunction with the stress regime information by a proprietary software code called Logging Mechanical Properties (LMP™) that emulates static mechanical properties including Young’s modulus, Poisson’s ratio and compressive strengths (at user specified confining pressures). A minimum horizontal stress is also calculated (Ref. 7, Ref. 5, Ref. 8). The workflow of the LMP™ model is illustrated in Figure 8.

SHALE LITHOFACIES UTILIZATION

As described earlier, in the integrated petrophysical approach, shale lithofacies have been identified using chemistry and mineralogic inputs. One of the objectives of doing this is to locate the lithofacies that are most favorable for gas recovery, have excellent TOC content and brittleness. Often this is the siliceous mudstone facies. The number and type of lithofacies may vary from one shale gas play to another. Currently we have validated lithofacies for the Barnett Shale, Woodford Shale and Haynesville Shale and are developing models for other shale plays. When the lithofacies information is integrated with the geomechanical static properties analyses, fracture indicators are calculated. Using a “stop light” identification technique, the zones in a given well that are most favorable for fracture initiation

\[ \rho_{TOC} \] is the density of organic matrix components, determined from core and/or computed mineralogic TOC calibration

\[ \rho_m \] is the density of inorganic matrix components, determined using mineralogy from geochemical logs.
are flagged green and those that are the most unfavorable flagged red When evaluated in context with the other reservoir parameters the fracture indicators and lithofacies flags can be utilized to recommend the optimal location to place a horizontal lateral well or evaluate probable hydraulic fracture design effectiveness (Ref. 5, Ref. 7, Ref.8). Figures 9&10 describe the lithofacies and fracture indicators developed for the Barnett Shale (Ref. 5). Figures 11&12 describe the lithofacies and fracture indicators developed for the Woodford Shale (Ref. 8).

CONCLUSIONS

An integrated petrophysical approach to evaluate shale gas reservoirs has been developed which provides advanced mineralogy, direct measurement of the TOC content and detailed geomechanical analyses. The methodology has been applied to several shale gas plays in North America and can be used to assist in effective hydraulic fracture stimulation design and optimizing the location of horizontal laterals within shale reservoirs.

ACKNOWLEDGEMENTS

I need to acknowledge the numerous geoscientists and engineers who were involved in the development of the technical methodologies used in this approach and the operating companies who allowed the interpreted results their shale gas wells to be included.

REFERENCES

FIGURES

Figure 1. The Barnett, Haynesville, Woodford and Marcellus Shales are among the current most active shale plays in the United States

![US Shale Gas Basins](image1)

Figure 2. Most of the projected increase in unconventional gas production is projected to come from shale gas reservoirs

![US Unconventional Gas Production Capacity](image2)
Figure 3. The Barnett Shale is jet black in color, has a high percentage of Quartz and is over 91% clay sized particles.
Figure 4. Shale gas petrophysical evaluation requires not only a variety of logging technologies but also rock samples and a suite of core analyses.

Figure 5. The comparison of log determined chemistry and mineralogy to core XRF and XRD analyses results shows good agreement.

**Feldspathic Sand @ 5116 ft (West Texas Well)**

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Figure 6. There is no “TYPICAL” Shale gas reservoir mineral composition. Significant variations can be seen between these for active North American shale plays.
Figure 7. The calculated water saturation and porosity from the integrated petrophysical approach compare favorably with the core derived water saturation and porosity measurements for the Cattle and Cometti wells in the Woodford Shale.
Figure 8. The LMP\textsuperscript{TM} workflow used in the integrated petrophysical approach provides mechanical rock properties that incorporates changing mineral composition.

Figure 9. Barnett Shale Lithofacies were developed and validated that allow the most favorable shale intervals to be identified.
Figure 10. A Barnett Shale Integrated Petrophysical Analysis illustrating the use of lithofacies and frac indicators for selection of horizontal lateral location.
Figure 11. *Woodford Shale Lithofacies were also identified*

- **Siliceous Mudstones** → *Fracture Targets*
  - *Gas Recovery Zone*
  - *High TOC – Gas Zone*
  - *Fracture Barriers*
  - *Fracture Antagonists*

Use geochemical logs to locate siliceous lithofacies favorable for hydraulic fracture. Use lithofacies, mineralogy, TOC, NMR porosity, and acoustic data to compute horizontal stress.

- **Siliceous Mudstones** → *Favorable Fracture - Min. Horizontal Stress*
- **Carbonate Mudstones** → *Non-Favorable Fracture - Max. Horizontal Stress*

Must also locate lithofacies that are hydraulic fracture energy barriers. Use mineralogy, TOC, porosity, and acoustic data to compute horizontal stress.
Figure 12. A Woodford Shale Integrated Petrophysical Analysis which shows good comparison to core analyses results