Best practices predicting unconventional reservoir quality

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Introduction

Unconventional reservoirs have proven challenging for quantitative interpretation methods to help define well spacing or optimal fracturing methods. These reservoirs are typically composed of complex geological systems of rocks, fluids, and organic material embedded in heterogeneous facies due to changes in stress, pressure, and temperature states over geological time. Identifying and characterizing independent physical properties in unconventional reservoirs requires an integrated effort among geoscientists – geologists, geophysicists, petrophysicists, and geomechanicists – to unfold key geological, elastic, and mechanical properties from borehole and subsurface data, with the aim to predict "sweet spots" from quantitative indicators of reservoir quality. This interdisciplinary collaboration ultimately reduces interpretation uncertainties quantitatively and improves returns on investment drilling wells optimally.

Quantitative Geoprediction Workflows

Unconventional rock-physics-based geoprediction is a time- and resource-effective approach, compatible with the fast turnaround of unconventional drilling schedules. Rock physics, defined as the link between the geological knowledge from wells, fluids and organic material present in formation pore spaces and their intrinsic seismic signatures, provides valuable technical insight on independent physical rock properties to predict elastic, geomechanical, and related geological conditions from locally-calibrated poro-elastic models in the subsurface.

Quantitative geoprediction workflows have been developed and successfully applied in multiple unconventional plays to integrate distinct sources of information from direct borehole measurements and indirect subsurface seismic measurements to identify, analyze, calibrate, and interpret reservoir quality indicators. Tailored to fit the purpose of characterizing and/or monitoring each tight reservoir, these workflows ascertain which geophysical and geomechanical properties, predicted from prestack seismic inversion, will correlate with good reservoir quality and good flow properties.

Unconventional reservoirs can be modeled as geological facies systems composed of minerals, pores, and organic material (total organic carbon) in the form of kerogen (pseudo-solid) and bitumen (pseudo-fluid) phases (Fig. 1a). Key independent physical properties of unconventional reservoirs may require poroelastic (compressional and shear moduli), geomechanical (stress and strain), and geological (geopressure and fracture gradient) inferences both at wells and away from wells, a typical challenge to operations geoscientists. We introduce a quantitative geoprediction workflow that integrates distinct sources of information from borehole (direct) and subsurface (indirect) measurements to identify, analyze, calibrate, and interpret reservoir quality indicators (Fig 1b).

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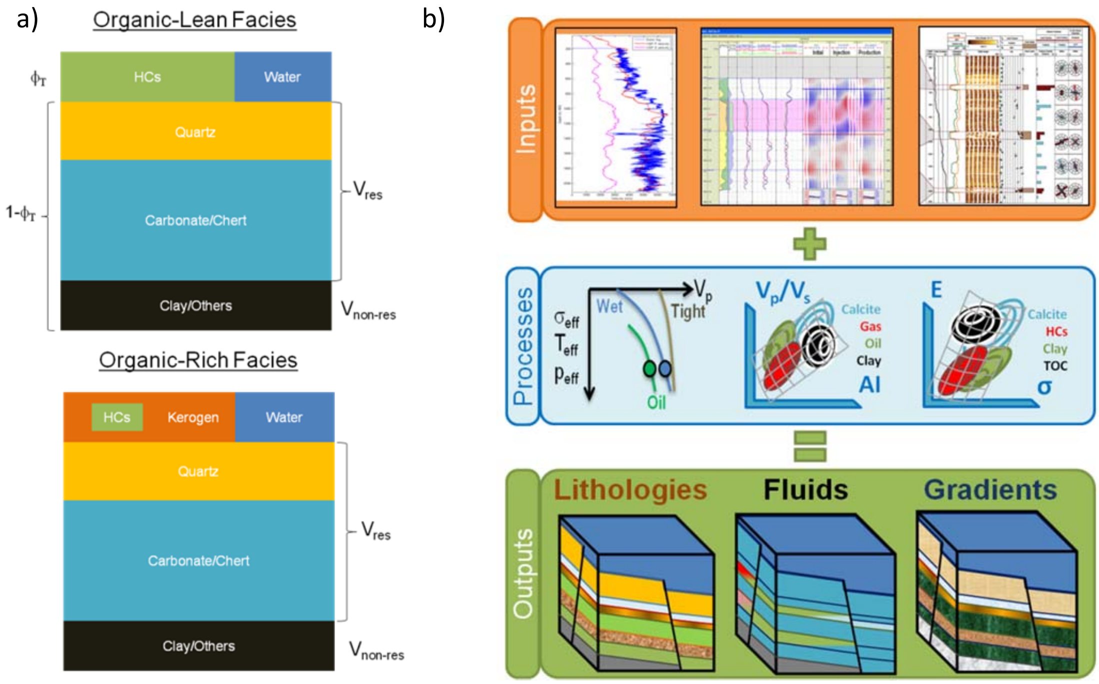

Figure 1. Unconventional reservoir models (a) and a typical Integrated Geoprediction workflow (b)

Key Unconventional Reservoir Quality Indicators

Unconventional reservoirs are complex, heterogeneous and/or anisotropic in nature, and their geoprediction implies a thorough integrated assessment of facies quality on a case-by-case basis. Complex geologic systems where organic material is embedded in heterogeneous formations under the effect of stress, pressure and temperature, and fluids trapped in low-porosity formations in small volumes, relative to the rock formation, make their seismic signal not easily interpretable.

Our integrated geoprediction workflow (i) identifies incompressibility, rigidity, and pore content by facies, (ii) analyze rock and TOC relationships between these properties based on core, log, and test data from wells, (iii) calibrate elastic, anisotropic, and mechanical properties and gradients, and (iv) interpret most-likely indicators (DLI for lithofacies, DTI for TOC, DFI for fracture gradient) associated to reservoir quality and completion to interpret “sweet spots” (e.g. high-TOC, brittle/fractured facies) in a quantitative manner (Figures 2 and 3).

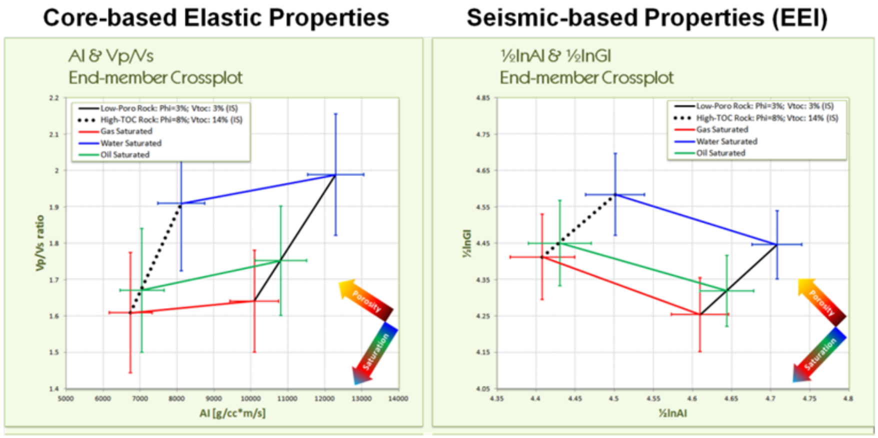

Figure 2. Example of core and seismic end-members as reservoir quality indicators in a tight gas shale play (Malaver, 2013)

In order to identify unconventional sweet spots with best reservoir quality and optimal fracture placement, resulting in strong initial production and sustained flow, integrated geoprediction workflows applied (Figure 3.a) typically consist of the following steps:

- Identify compressional and shear moduli, and pore content by facies;
- Determine TOC volume by facies, based on core and log data from wells;
- Determine relationships between elastic, geomechanical and geological properties by facies;
- Correlate facies and elastic properties under the presence of open fractures;
- Underpin rock physics models by developing a geological model taking into account pressure generation, shale diagenesis, and their effect on porosity preservation; and
- Quantitatively interpret most-likely indicators of reservoir quality at sweet spots.

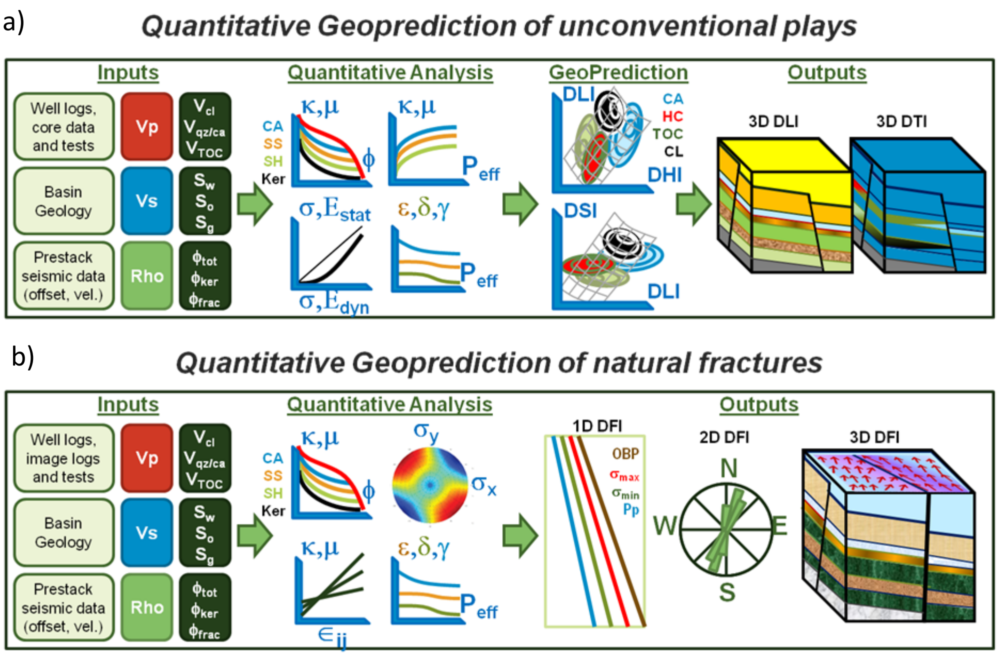

Figure 3. Quantitative Geoprediction workflows for (a) unconventional plays and (b) natural fractures

In order to develop an optimal drilling plan, such that horizontal wells stay within the fractured formation and intersect a maximum number of natural fractures, some of the additional key processes performed in integrated geoprediction workflows (Figure 3.b) have involved:

- Estimating TOC thermal maturity of organic-rich facies from petrophysical logs;
- Estimating elastic properties (compressional and shear moduli) from seismic amplitude versus offset inversion (including dynamic geomechanical properties)
- Converting geomechanical properties to populate a static mechanical earth model required for drilling and stimulation applications; and
- Correlating elastic properties calibrated from image logs at lithofacies with open fractures.

Figure 4 shows examples from tight carbonate reservoir characterization and monitoring (Malaver et al, 2004), porosity prediction in tight carbonate facies (Hardy, 2013), and fracture gradient prediction from image logs and seismic mechanical properties (Emsley et al, 2012; Mildren et al, 2013), demonstrating the complexity of technical challenges and the need to involve geologists, geophysicists, and geomechanicists to enhance the understanding and reduce the risk exploring and developing unconventional reservoirs effectively.

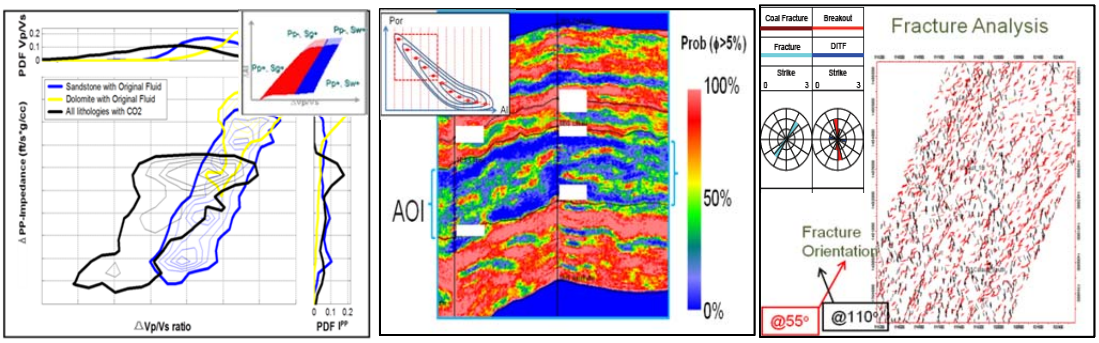

Figure 4. Examples of unconventional reservoirsaturation, porosity, and fracture predictions (Malaver et al, 2004; Hardy, 2013; Emsley et al, 2012; Mildren et al, 2013)

Conclusion

Integrated geoprediction workflows for unconventional reservoirs provide a crucial quantitative link between well and seismic data via rock physics and geomechanical analyses. These workflows bring value to the E&P cycle by integrating invaluable input from geologists, geophysicists, and geomechanicists. Results obtained have enabled operators to identify, analyze, calibrate and interpret reservoir and completion quality using borehole and subsurface data, as well as optimize the process of drilling and completing cost-effective wells by targeting reservoir zones with high initial production as well as sustained, high flow rates.

Examples demonstrate the value of applying fit-for-purpose integrated geoprediction workflows to characterize unconventional facies over tight carbonate and organic-rich shale plays. Results showed (i) high correlation between fractured and unfractured facies interpreted from seismic AVO inversion attributes calibrated with unconventional rock physics models of elastic and geomechanical properties estimated from well core and log data, (ii) segments of a horizontal well that are worth fracturing, so that the resulting fractures are contained within the zone of high TOC, and (iii) gas shale sweet spots associated with high-TOC, fractured, tight facies.

About the authors

Cristian Malaver

Cristian Malaver is vice president of quantitative interpretation at Ikon Science. He is a geophysical engineer with more than 20 years of experience in integrating geoscience best practices for hydrocarbon exploration, development, and production around the globe. His main areas of expertise have involved technology development and technical management in unconventional rock physics, reservoir geophysics, and quantitative interpretation working for BHP Billiton, CEPSA, ADCO, EP Energy, and Occidental. Formerly, he worked in project management and field supervisory roles for geophysical and geological operations for ConocoPhillips and GAPS. Malaver holds a master's in geophysical engineering from the Colorado School of Mines, and a master of engineering from Universidad de los Andes.

Jorg Herwanger

Jorg Herwanger is head of special projects at Ikon Sciences, where he is focused on demonstrating how the company's software and services across rock physics, quantitative seismic interpretation, geomechanics, and pore pressure prediction are integrated into geoprediction workflows. A geoscientist with 15 years' experience in geophysics, geomechanics and rock physics, Herwanger started his career with Schlumberger, where he made contributions to time-lapse seismic and reservoir geomechanics. He also pioneered the technology of integrating 3-D and 4-D seismic data into building and calibrating geomechanical models. He was a European Association of Geoscientists & Engineers distinguished lecturer in 2009-10, and an EAGE education tour lecturer in 2011-12.

Michel Kemper

Michel Kemper is a co-founder of Ikon Science, and is responsible for incorporating the latest techniques and developments in the area of rock physics into the company's software portfolio. A petroleum engineer with 26 years of experience in geophysics, petrophysics and reservoir engineering, Kemper spent 13 years with Shell International in The Hague, Nigeria and London, where he made contributions to the interface between petrophysics and geophysics. In May 1999, he became team leader petrophysics/petro-acoustics at Ikoda Limited. It was during this time that RokDoc–now one of Ikon Science's main products–was started.

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