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Systemic Reservoir Characterization of Organic-Rich Mudstones

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Summary

Opinion is polarized on the merits of applying reservoir characterization methods to organic-rich mudstone petroleum systems ("shale gas" and "shale oil" resources). The proponents of characterization invest in the methodology as a means to adapt completion, stimulation and production design to specific reservoir characteristics in order to optimize recovery and minimize finding and development cost. Opponents of the method argue that the distributions of critical characteristics are of a scale and stochastic distribution that precludes meaningful prediction of inflow behaviour. For this group, best practices are founded upon investment in field pilots and engineered solutions, based on field performance, for continuous improvement of inflow and recovery characteristics.

For many operators, the strategic decision to embrace quantitative reservoir characterization as a critical element of their evaluation workflow is predicated on a risk-reward assessment. Specifically, can the investment in service and analytical expenses, as well as overhead costs and delayed onset of operations, produce a superior economic outcome to operations refinements in the field? At its most basic level, the question is simply whether or not characterization reduces uncertainty in a manner that manages risk.

Just as the introduction of new drilling, completion and stimulation technologies have made it possible to access previously recalcitrant reservoir types, the adoption of novel microscopy, porosimetry and related analytical technologies has revolutionized the ability to describe specific quantitative properties of microporous mudstone-dominated lithologies. By analogy with the widespread adoption of 3-D seismic as a fundamental risk management tool, an argument can be made that a reservoir characterization workflow incorporating technologies designed to image the unique scale and geometry of mudstone reservoirs has the potential to substantially reduce uncertainty. Such a workflow, however, must integrate such analytical modalities within a well-formed petroleum system model in order to realize meaningful benefits.

Introduction

Widespread adoption of multistage hydraulic fracturing of horizontal completions has afforded access to a broad range of low-permeability, heterogeneous reservoir types that previously precluded economic inflow and recovery. Among these play types, exploration and development of self-sourcing organic-rich mudstone deposits ("shale gas" and "shale oil") benefits greatly from this operational innovation. The rapidity with which the upstream oil and gas industry embraced such play types initially outpaced the state of knowledge with respect to characterization of "unconventional" reservoirs (Curtis, 2002). In the course of the past decade, however, applied research and development has produced numerous analytical tools and proposed workflows (Slatt et al., 2008) that have closed this gap considerably. Specifically, advanced geochemical and geomechanical petrophysical tools (Sondergeld et al., 2010), pulse-decay permeametry (Cui et al., 2009), and quantitative image analysis employing Focused Ion Beam - Secondary Electron Microscopy ("FIB-SEM") (Loucks et al., 2009; Ross and Bustin, 2009; Wirth, 2009) offer unprecedented means to quantify critical reservoir characteristics of mud-dominated successions (Passey et al., 2010). As such, these tools are now routinely incorporated into sophisticated characterization workflows.

With the notable exceptions of the Barnett Shale natural gas resource play and the Bakken oil play, production performance data for most mudstone reservoirs are restricted to early-stage behaviour and ultimate decline and recovery characteristics are subject to high degrees of uncertainty. Faced with this uncertainty, operators have the choice of relying on pre-drill characterization or post-drill inflow optimization to manage recovery risk. In practice, most operators attempt to find an appropriate balance between these two approaches. Given that both approaches represent risked investment decisions with significant capital and operating expense implications, fiscal responsibility dictates critical assessment of reservoir characterization workflows in order to invest in the process that combines acceptable uncertainty reduction with high capital efficiency.

Theory

Literature abounds on specific reservoir properties of organic-rich mudstones, but broader investigations of these rocks as autogenic (self-sourcing) petroleum systems (e.g.: Pollastro et al., 2007) are significantly less common. The depositional, structural, and thermal history embodied in a well-formed petroleum system model provides the requisite context to relate individual components to a genetic whole. For example, in the case of autogenic organic-rich mudstone petroleum systems, the intimate relationship between the composition, abundance, and thermal history of reactive kerogen and resultant microporosity evolution in disseminated organic matter macerals is an important determinant of storage and flow capacity. These properties, moreover, cannot be divorced from consideration of the inorganic constituents of the reservoir (Ross and Bustin, 2009). Furthermore, this complex interrelationship is a dynamic property that evolves in concert with both large-scale basin dynamics and local thermal and mechanical perturbations. As such, reservoir characterization workflows that emphasize quantification of specific static attributes without the beneficial broad genetic context of a comprehensive petroleum system model risk becoming mired in empiricism at the expense of predictive capacity. An efficient workflow, therefore, stipulates a balanced approach integrating quantitative analyses of the critical attributes influencing storage capacity, flow capacity and geomechanical properties within a genetic framework that relates such attributes in both space and time ("systemic characterization").

Discussion

Work has commenced on a research theme devoted to constructing models for several genetically distinct autogenic organic-rich mudstone petroleum systems in the Colorado Group of the Western Canada Sedimentary Basin. The scale of investigation of individual projects under this thematic umbrella spans fifteen orders of magnitude from the evolution of microporosity to three-dimensional burial history models for the entire span of the basin. The Colorado Group presents an exceptional opportunity for petroleum system modeling due to the wide range of preserved thermal maturities, variable burial histories and depositional motifs across the foredeep, forebulge and back-bulge depozones (DeCelles and Giles, 1996), and documentation of well-constrained high-frequency allostratigraphic framework (Nielsen et al., 2008; Roca et al., 2009; Tyagi et al., 2007). In addition, both oil and gas (thermogenic as well as biogenic) plays are available for comparative and illustrative purposes.

The immediate objective of the research is to integrate quantitative reservoir properties within petroleum system models for understanding the genesis of various unconventional plays in the Colorado Group, as well as to provide the basis for a regional resource assessment. A significant impact of this work, however, will be the development of a reservoir characterization workflow that embodies the principles described earlier, and the evaluation of the relative merits of such systemic characterization in comparison to alternative approaches. The insights gained from this comparison are intended to provide competitive advantage for the development of future energy resources.

Conclusions

The efficacy of systemic reservoir characterization of autogenic organic-rich mudstone petroleum systems has not yet been rigorously established, but the underlying principle has its basis in a simple truism that has successfully guided generations of geoscientists - a field observation is only as good as the story in which it appears. Predictions of geological properties are not easily reduced to extrapolation or interpolation between measured values. They occupy the stage with numerous other players, all working from the same script, and all interacting in a manner determined in the previous scene. Reservoir characterization without due consideration of the history and components of a petroleum system undermines the expense and effort of measurement, and may leave the critics howling.

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