Gas Production Forecasting from Tight Gas Reservoirs: Integrating Natural Fracture Networks and Hydraulic Fractures

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This research proposes a multidisciplinary, fully integrated reservoir characterization, involving detailed geologic interpretation, rock properties, natural fractures, hydraulic fractures and well performance of tight gas sands in the Uinta Basin, with particular emphasis on the Mesaverde formation. This short report is not intended to serve as a comprehensive literature review on all of the components of this research program. Some selected references are reviewed followed by a brief summary of the current state of the art in categories that are important in this project.

The Geology and Fracture Characterization

The Mesaverde Total Petroleum System (TPS) is described in detail the U.S. Geological Survey, 2003, Digital Data Series DDS-69-B (USGS, 2003)[1], and in several Utah Geological Survey Open File Reports (Anderson, 2005[2] and Longman and Koepsell, 2005[3]). Gas is produced from the Tertiary Wasatch Formation and numerous formations within the Cretaceous Mesaverde Group. The total thickness of the Mesaverde TPS is more than 9000 feet in the Uinta Basin with a maximum depth to the base of more than 19,000 feet. A generalized cross section of that part of the Mesaverde Group is shown in Figure 1. Production from the tight gas sands within the Mesaverde TPS is primarily from the Wasatch and upper Mesaverde in eastern Uinta Basin, but exploration has expanded the play to the deeper basal portions of the Mesaverde TPS as well as into the western Uinta Basin. In the Uinta Basin the Mesaverde Group includes in descending order, Price River (western Uinta Basin), Tusher, Farrer, Neslen, Sego, Castlegate, and Blackhawk Formations. Porosities commonly range from 5 percent to more than 8 percent with permeabilities generally in the range of 0.01 to 0.1 millidarcies. The USGS calculates total undiscovered resources for the Uinta Basin continuous and Uinta Basin transitional assessment units of the Mesaverde TPS as: 5.0 TCF (95% probability) to 14.2 TCF (5% probability) with 8.5 TCF at 50% probability. Vertical and lateral distribution of depositional patterns, petrology, diagenetic and burial history all influence the reservoir quality, natural fracture distribution and the effectiveness of hydraulic fracturing.

[1] U.S. Geological Survey, 2003, Petroleum Systems and Geologic Assessment of Oil and Gas in the Uinta-Piceance Province, DDS-69-B.
[2] Anderson, P., 2005, Mesaverde Gas of Southeastern Utah, UGS Open File Report 460.
[3] Longman and Koepsell, 2005, Defining and Characterizing Mesaverde –Eastern Uinta Basin, UGS Open File Report, DVD.

The Department of Energy conducted a comprehensive Multiwell Experiment (MWX) in the Piceance Basin to provide geologic characterization, obtain physical property data, and perform stimulation experiments in the Iles and Williams Fork Formations in the cretaceous Mesaverde Group (Nelson, 2003)[4]. It was inferred that gas production was controlled by a single set of regional fractures trending west-northwest. Some variability has been observed in larger data sets. A fracture orientation map in the region is shown in Figure 2.

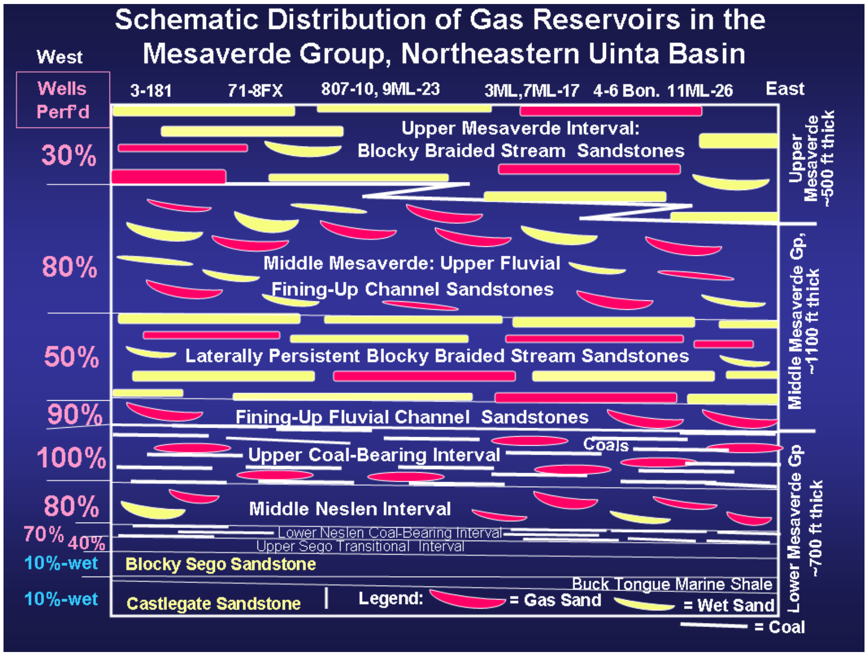

Figure 1: Schematic diagram showing the distribution of gas reservoirs in the Mesaverde Group of the Uinta Basin.

Lessons learned from this experiment will have to be calibrated with our present day understanding of the regional stresses in the Mesaverde in the Uinta basin, and by the fact that horizontal wells and fracturing through horizontal wells are common practices today.

Natural Fractures and Hydraulic Fractures

The relative orientation of the current in-situ stress field with the dominant fracture systems plays a critical role in increased gas production. Colinearity of the strike of the dominant natural fracture system and the maximum principal stress is accompanied by hydraulic fracturing that is poorly connected to large volumes of the reservoir laterally away from the fracture, as in the Mesaverde at the MWX site (see for

[4] Nelson, P.H., 2003 Chapter 15: A Review of the Multiwell Experiment, Williams Fork and Iles Formations, Garfield County, Colorado, in *Petroleum Systems and Geologic Assessment of Oil and Gas in the Uinta-Piceance Province*, DDS–69–B, U.S. Department of the Interior U.S. Geological Survey.

example Nelson, 2003[5]). At the other extreme is a situation like the Barnett shale, in an extensional basin, or at least in a situation where natural fractures and the maximum horizontal stress direction are directionally diverse. Microseimic evidence strongly supports interaction of existing and hydraulic fracturing discontinuities.

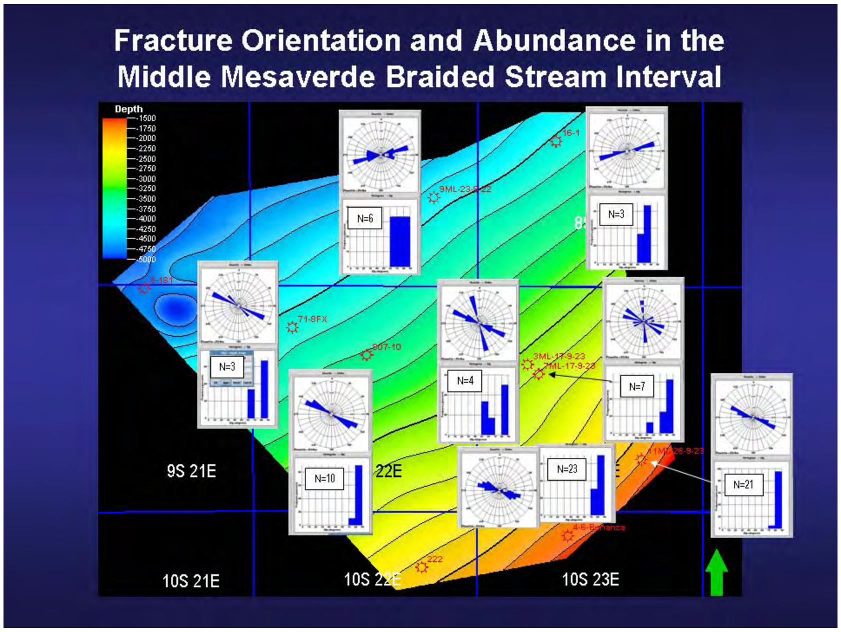

Figure 2: Fracture orientation map in the middle Mesaverde with several wells showing the west-northwest trending fracture sets, and some wells showing different orientations (courtesy UGS).

It is well known that the relative orientations of existing fractures and the modern stress field, plus the mechanical characteristics (shear and tensile strengths) of the existing discontinuities and native rock, combine with directional anisotropy in the mechanical properties to govern the potential for interconnecting with a substantial network of natural fractures. In fact, this has been recognized in the geothermal industry (shear-induced natural fractures) and for improved stimulation techniques (Bill Gunter[6], Alberta Research Council, personal communication).

Hydraulic fractures, which are essential for economic production from tight gas sands, with a few exceptions, are currently modeled as mathematically simplistic entities. For example, Economides and Nolte, 2000,[7] describe commonly used simulators – all of which model the created fracture system as a single, planar crack with one-dimensional fluid loss into an equivalent porous medium. Particularly with

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[5] Nelson, P.H.: "Chapter 15: A Review of the Multiwell Experiment, Williams Fork and Iles Formations, Garfield County, Colorado," in *Petroleum Systems and Geologic Assessment of Oil and Gas in the Uinta-Piceance Province, Utah and Colorado*, USGS Uinta-Piceance Assessment Team U.S. Geological Survey Digital Data Series DDS–69–B, U.S. Department of the Interior U.S. Geological Survey, 2003.
[6] Personal Communication with John McLennan, Senior Investigator for the University of Utah.
[7] Economides, M.J. and Nolte, K.G.: *Reservoir Stimulation*, John Wiley &Sons, Ltd., New York, NY, 2000.

the advent of microseismic technology (Urbancic and Maxwell, 2002)[8] and even earlier with mine-back experiments (Warpinski, 1985)[9] it has become evident that fractures evolve as a complicated network in three dimensions - creating new fractures, reactivating or reopening existing fractures and parting bedding plane interfaces.

Standard simplified hydraulic fracture modeling means that the complexity and true character of hydraulically created fracture systems is not represented. Even more important, overly simplified representations of fractures are incorporated in production forecasting models (refer to Figure 3).

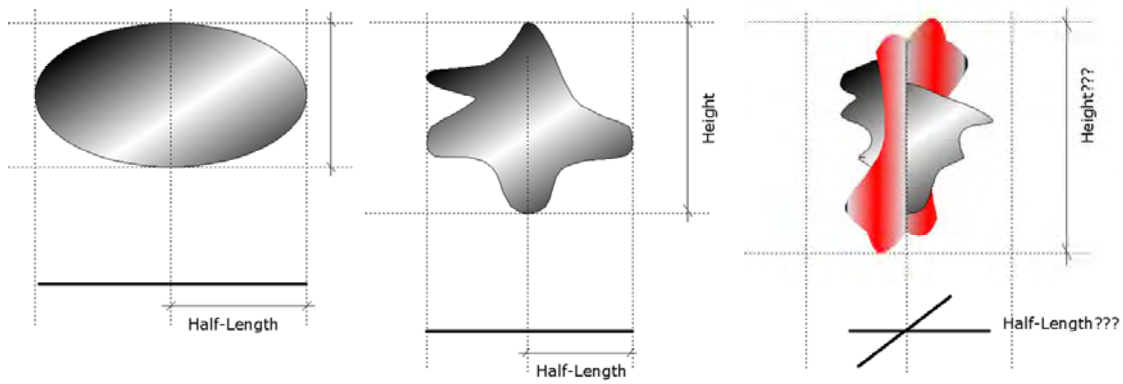

Figure 3: A schematic indicating the necessity for representing hydraulic fracturing as being more complicated than rudimentary propagation of a single planar fracture. The top illustration in each panel is an elevation view of a fracture simulation. The lower illustration is a plan view. At the left is the most commonly used hydraulic fracturing simulation – a single planar fracture with a vertical cross-section that is relatively regular (pseudo-three-dimensional model). A restricted number of fracture simulators allow more irregular in-plane profiles (middle panel). These are sometimes referred to as three-dimensional models, but this is a misnomer since only one planar feature is represented. The proposed technique will allow representation of any number of fractures, or fracture segments, in any plane. For simplicity, only a very rudimentary example is shown. ***Accurate reservoir simulation and refined fracture design are inhibited by the in-plane restrictions of current fracture simulations.***

While, as demonstrated by the reference sampling above, there has been some interest in modeling complex, non-planar, fracture systems, practicality of the simulations and acquiring relevant input has – up to now – discouraged development. Simulation methodologies and computational efficiency have alleviated these restrictions and motivate this project.

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[8] Urbancic, T.I., and Maxwell, S.C.: "Source Parameters of Hydraulic Fracture Induced Microseismicity," SPE 77439-MS, SPE ATCE, San Antonio, TX, 29 September-2 October 2002.

[9] Warpinski, N.R.: "Measurement of Width and Pressure in a Propagating Hydraulic Fracture" SPEJ, Vol. 25, No. 1, February 1985, 46-54.

Fluid Flow Simulations

In these low-permeability formations, fracture geometries and connectivities are of paramount importance, when simulating fluid flow. At the University of Utah, we have developed a series of finite-element models capable of explicitly representing the fracture networks and hydraulic fractures (Fu et al., 2005[10]; Yang et al., 2006[11]). Explicit representation of fracture sets in tight gas reservoir simulations is not common. There have been several papers on considering hydraulic fractures in naturally fractured reservoirs (for example, Hossain et al., 2002[12], Osorio, et al., 1995[13], Bagheri and Settari, 2008[14]). The ability of simulating explicitly the presence of deformable fractures and fluid flow through them is critical for studying the process of hydraulic fracturing in naturally fractured rock. The ability to simulate gas flow through complex sets of hundreds of fractures is also numerically challenging and will be addressed during this project.

When flow of water is also involved, relative permeabilities of all fluids in question are also important. Based on relative permeability measurements from tight-gas cores, Shanley et al. (2004)[15] discussed the "permeability-jail" concept. The relative permeabilities for tight-gas formations in this approach and the resulting initial water/gas saturations are very different. One of the primary questions in production of gas from tight-gas formations is the determination of the interplay between these types of multiphase flow effects and the geometric effects discussed above, and will be addressed in this project.

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[10] Fu, Yang and Deo, 2005, Three-Dimensional, Three-Phase Discrete-Fracture Reservoir Simulator Based on Control Volume Finite Element (CVFE) Formulation, SPE 93292.
[11] Yang and Deo, 2006, Modeling of Multilateral and Maximum Reservoir-Contact Wells in Heterogeneous Porous Media, SPE 99715.
[12] Hossain, Rahman and Rahman, 2002, A Shear Dilational Stimulation Model for Production Enhancement from Tight Gas Reservoirs, SPE J., June, 183-195.
[13] Osorion, Chen and Teufel, 1995, Numerical Simulation of Coupled Fluid-Flow/Geomechanical Behavior of Tight Gas Reservoirs with Stress Sensitive Permeability, SPE 39055.
[14] Bagheri and Settari, 2008, Modeling of Geomechanics in Naturally Fractured Reservoirs, SPE Reservoir Evaluation and Engineering, 108-118.
[15] Shanley, et al., 2004, Factors Controlling Prolific Gas Production from Low-Permeability Sandstone Reservoirs, AAPG Bulletin, No.8, 1083-1121.