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An Overview of Shale Gas Exploration and Current U.S. Plays

Gas-productive shale formations occur in Paleozoic and Mesozoic rocks in the continental United States. Typical of most unconventional or continuous-type accumulations (Curtis, 2001; USGS, 1995), these systems represent a potentially large, technically-recoverable gas resource base, with smaller estimates for historical production and proved reserves. The concept of the resource pyramid was first used in the late 1970s for analyzing natural gas accumulations in low-permeability reservoirs (Sumrow, 2001). The tip of the pyramid represents the most economic and easily accessible portion of the resource. If exploration and development companies are to access the gas resources toward the base of the pyramid, some combination of incrementally higher gas prices, lower operating costs and advanced technology will be required to make production economical. Production of gas deeper within the resource pyramid is required to fully realize the potential of this type of petroleum system.

The first commercial U.S. natural gas production (1821) came from an organic-rich Devonian shale in the Appalachian basin (Peebles, 1980). The Devonian Antrim Shale of the Michigan basin, the most active U.S. gas play in the 1990s, became commercially productive in the 1980s, as did the Mississippian Barnett Shale of the Fort Worth basin and the Cretaceous Lewis Shale of the San Juan basin (Hill and Nelson, 2000). Shale-gas production has increased through the years, for example by more than seven-fold from 1979 to 1999. In 1998, shale gas reservoirs supplied 1.6% of total U.S. dry gas production and contained 2.3% of proved natural gas reserves (EIA, 1999).

Understanding the geological and geochemical nature of organic shale formations and improving their gas producibility have been the challenge of millions of dollars worth of research since the 1970s.

From that research, for example, we have learned that these fine-grained, clay- and organic carbon-rich rocks are both gas source and reservoir rock components of the petroleum system (Martini et al., 1998). The gas may be of either thermogenic or microbial origin and stored as sorbed hydrocarbons, as free gas in fracture and intergranular porosity and as gas dissolved in kerogen and bitumen (Martini et al., 1998; Schettler and Parmely, 1990). Trapping mechanisms are typically subtle, with gas saturations covering large geographic areas (Roen, 1993). Postulated seal-rock components are variable, ranging from bentonite (San Juan basin) to shale (Appalachian and Fort Worth basins) to glacial till (Michigan basin) to shale/carbonate facies changes (Illinois basin) (Hill and Nelson, 2000; Walter et al., 2000; Curtis and Faure, 1997).

To date, unstimulated commercial production has been achievable in only a small proportion of shale wells, those that apparently intercept natural fracture networks. In most other cases, a successful shale-gas well requires hydraulic stimulation. Together, the Devonian Antrim Shale of the Michigan basin and Devonian Ohio Shale of the Appalachian basin accounted for about 84% of the total 380 Bcf of shale gas produced in

1999 (Hill and Nelson, 2000). However, annual gas production is steadily increasing from at least four other major organic shale formations that subsequently have been explored and developed—Devonian New Albany Shale in the Illinois basin, Mississippian Barnett Shale in the Fort Worth basin, Mississippian Fayetteville Shale in the Arkoma basin and Cretaceous Lewis Shale in the San Juan basin. In fact, production from the Barnett Shale is rapidly surpassing that of the earlier-developed plays.

Five U.S. shale formations that presently produce gas commercially exhibit an unexpectedly wide variation in the values of five key parameters. These parameters are: (1) vitrinite reflectance (%R_o), a measure of thermal maturity of the kerogen; (2) fraction of gas present as adsorbed gas; (3) reservoir thickness; (4) TOC; and (5) gas-in-place resource per acre-foot of reservoir. Parameters widely different, for example, for the Antrim Shale of Michigan still permit commercial gas production from other fractured, organic-rich shales. Only the Antrim and New Albany shales produce significant amounts of water. This co-produced water is similar to that typical of coalbed methane production (Ayers, 2002), except that no significant reservoir dewatering is required prior to initiation of shale gas production.

This presentation will address the significance of these key parameters and three considerations for enhancing exploration success.

The degree of natural fracture development in an otherwise low-matrix-permeability shale reservoir is a controlling factor in gas producibility (Hill and Nelson, 2000). Permeability enhancement may also be related to facies changes between organic-rich shales and siltier shale units (Caramanica, 1988). Variations in produced-water chemistry may also provide exploration leads in a basin (Martini et al, 1998; Walter et al., 2000).

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