COMPARATIVE ANATOMY OF DEVONIAN SHALE PLAYS IN THE APPALACHIAN, ILLINOIS AND MICHIGAN BASINS

BOTTOM LINE

Shale gas plays have exploded across the United States in recent years following the success of the Barnett shale play in Texas. New technologies and new strategies are needed to develop the gas shales in the Appalachian, Illinois and Michigan basins.

PROBLEM ADDRESSED

Gas shale plays require different strategies than traditional oil and gas exploration and development. The key to success is a complete understanding of the reservoir using an integrated geological, geophysical and reservoir engineering approach to development. Understanding the challenges before drilling is the best path to success.

KEY WORDS:

Devonian Shale	Appalachian Basin
Illinois Basin	Michigan Basin
Antrim Shale	Barnett Shale
Shale Gas	Adsorbed Gas
Frac Treatment	Resource Assessment
Stimulation	Hydraulic Frac
Drilling Technologies	Completion
New Albany Shale	Thermogenic
Biogenic	Total Organic Carbon (TOC)
Hydrocarbon Window	Thermal Maturity

TECHNOLOGY OVERVIEW

Schlumberger Data & Consulting Services conducted a panel discussion "Hot Shale Play—Challenges, Potential and New Technology"

The first gas shale recovery in the United States was in 1821 near Fredonia, New York from the Dunkirk Shale. The first significant gas shale play did not occur for another 100 years. Big Sandy Field in Western Kentucky was discovered in 1921. It was recognized as one of the largest gas accumulation in the U.S. in 1935. Shale gas production had a rebirth in the 1970s and 1980s with the U.S. DOE Eastern Shale Gas Program. The most significant development of the period was the Antrim Shale play in the Michigan Basin, starting in 1987 and continuing today.

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SPEAKERS:

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The Barnett Shale in north Texas, starting in 1997, set the stage for a great expansion in exploration and development of gas shale plays. Barnett production surged from 30 Bcf in 1997 to 700 Bcf in 2006. The success of the Barnett was based on technologies unavailable during previous periods of interest in gas shales: horizontal drilling, multiple frac techniques, 3-D seismic for natural fracture detection, new petrophysics analysis and increased reservoir understanding.

Topics covered by the panel included: role of geophysics in exploration and development (Tolle), geology and petrophysics of shale reservoirs (Kaufman), drilling and completion technology for shale reservoirs (Walker), and reservoir evaluation and reserves in shale reservoirs (Boyer).

Important considerations for optimizing production from gas shales are to realize that the reservoirs are heterogeneous, structured and highly variable. Geophysics and 3-D seismic studies prior to drilling are necessary to define the play, to identify the sweet spots, to understand what controls the shale heterogeneity, and to select drilling locations and completion methods. Because gas shale development is dependent on fractures, geophysical analysis uses several techniques of amplitude and azimuth evaluation. Analysis of natural fracture patterns is necessary in planning the path of horizontal drilling.

Petrophysical evaluation of gas shale is used to quantify the gas as adsorbed or free, to identify the matrix permeability, fracture networks and fracture permeability, pressure, and to predict production. Knowledge of shale mineralogy, kerogen and clays, and how methane gas is formed is necessary to develop a shale gas play. Vertical and lateral heterogeneity in the shale is due to changes in depositional composition, terrigenous and carbonate input, anoxic conditions, and post depositional processes, such as diagenesis and mineralization. Geomechanical study of present day fractures and stresses, and regional paleo-stress patterns should be used in planning the frac design to ensure borehole stability. Because most gas shales have better lateral continuity than vertical, this knowledge of fracture patterns helps one to place horizontals in the sweet spots for maximum productivity.

Modern drilling and completion technologies are the key to optimization of shale gas plays. Multi-lateral wells and multi-stage hydraulic fractures in the horizontal legs significantly increase gas production. Logging suites and imaging logs provide the information to design frac treatments. Fracture geometry and determining the height that fractures will grow is dependent on identification of potential frac barriers, interbedded water sands, and structural conditions. Imaging logs can be used to study the impact that clay laminations will have on vertical fractures. Fluid incompatibility with the reservoir is the major consideration regardless of the basin or the play.

The most common problems in shale gas development are predicting average production, range in production and how many wells need to be drilled to answer these questions. Production forecasting methods use volumetric calculations, decline curves, material balance and reservoir simulation. These calculations require basic reservoir parameters including: initial pressure, gas isotherms, free gas content, pressure, and production data.
Gas shales are complex reservoirs and the technology to produce them is evolving at an exponential rate. Reserves and productivity appear to be maximized in areas of the reservoir where the most complex fractures are created. Shale gas recovery will continue to increase as our ability to model geologic, reservoir and geomechanical properties improves.

Assessment of Undiscovered Natural Gas Resources in Devonian Black Shales, Appalachian Basin, Eastern USA - Robert Milici

Technically recoverable undiscovered hydrocarbon resources include oil, natural gas and natural gas liquids. Oil and gas accumulation in Devonian shale reservoirs are trapped in structural, stratigraphic and combination traps. Resources include blanket-like accumulations commonly in multi-storied reservoirs, and coalbed methane in radioactive black shales and tight sandstones. Known continuous oil and gas resources in the Devonian in the Eastern U.S. include Northwestern Ohio shale, Greater Big Sandy shale, Devonian siltstones and shale, Marcellus shale, Catskill sandstones and siltstones and the Brea sandstone. Maps, isopachs and cross sections are provided to illustrate the geographic range and thickness of these deposits. Thermal maturity is compared for radioactive black shales in New York, Pennsylvania, Ohio, West Virginia and Kentucky. Structural geology and features including the Rome Trough in eastern Kentucky, Stone Mountain in Tennessee, and the Appalachian fold and thrust belts are related to well density and historical production.

A qualitative assessment of gas recoverability from Devonian shales in the Appalachian Basin shows 18 mapped plays. Per well estimates of technically recoverable gas range from 300-400 Bcf in West Virginia and Ohio to 500-700 Bcf in southeast Kentucky and southwest West Virginia to as high as 1,250 Bcf in eastern Kentucky. The hottest new play in the Appalachian Basin is the Marcellus shale, which extends from northern Alabama, through Tennessee, Kentucky, West Virginia, Ohio, Pennsylvania and New York.

Shale Reservoir Evaluation and Stimulation - Jim Fontaine

The great interest in shale plays is partly because shales are common, widespread in the Eastern U.S., and are in fact the most prevalent sedimentary rock on the planet. The most telling reason to investigate shale plays - everyone wants to be in on the next "Barnett" play. A map of U.S. shale plays shows nineteen major plays in basins from upstate New York to the California coast. Concentrations of plays and resources are in basins along the Gulf Coast, Rocky Mountains and Appalachian Mountain chain. Plays that have had the most development provide resource estimates: Antrim 35-76 Tcf, New Albany 86-180 Tcf, Devonian and Ohio plays 225-248 Tcf, Barnett 25-252 Tcf, Lewis and Mancos shales 97 Tcf.

A brief history of completion practices for the Barnett shale is of interest to compare to the potential development in the Devonian shales of the eastern U.S. Stimulation of Barnett wells began with CO_2 foam fracs in vertical wells in the 1980s, followed by gel and N_2 foam fracs. Massive hydraulic fractures and traditional water fracs in vertical wells were instituted in 1998 and 1999. Single-stage uncemented horizontal wells were attempted next, quickly followed by multi-stage cemented horizontals. Throughout the 2000-2006 period, longer laterals and more frac stages were experimented with using increased frac rates, more proppant and greater water volumes. By 2007 multi-laterals using frac sleeves and abrasive perforating coupled with up to 8-9 fracs per lateral were the norm. The learning curve for Mitchell Energy was over 10 years to develop a successful completion strategy. Newer plays in Appalachia can't expect to have the same success (no two shales are exactly alike), but they can and should take advantage of the learning curve.

Certain parameters must be met for shale plays to be successful. The organic matter content or total organic carbon (TOC) must be a minimum of 3-5%. Thermal maturity, measured by vitrinite reflectance, gives a measure of the maximum temperature the shale has been exposed to and whether or not the organic content has been baked enough to generate oil or gas. Rock mechanics and friability or the brittleness vs. malleability of the shale influences how well the shale will frac. Stress anisotropy or a low horizontal stress differential determines what type of frac can be performed. The presence of natural fractures in the shale increases the potential for fracing.

Shale stimulation requires an understanding of very complex rock mechanics, particularly fracture length and azimuth, used to determine the drainage area. Fracs are based on horizontal stress differentials. Microseismic fracs are a new technique developed to measure frac development in the reservoir. A typical stimulation for the Barnett shale consists of 400-800 lbs of proppant, 500,000 to 1,000,000 of slickwater (water containing a friction reducer) per stage, with rates of 50-100+ bpm as determined by the thickness of the zone. The goal is to breakup as much rock as possible to maximize the stimulated reservoir volume (SRV).

The major diagnostic tools for shale completion are logs, radioactive and chemical tracers, flowback analysis of produced water, 3-D seismic to identify complex geologic features like karst, faults and large open fractures, geochemical analysis for thermal maturity, and post-frac production logging to determine where the gas is coming from. The latest design ideas from the Barnett shale play include increased well density (500 ft offsets); multi-lateral wheel spoke design, gel sweeps as diversion techniques, horizontal refracs to access stranded reserves and dual laterals.

The biggest change to completion practices in shale production is the use of horizontal wells. Horizontals cost 1 ½ to 2 time more than a vertical well, but can produce 2 to 4 times the reserves. In Appalachia horizontal wells have an additional benefit of making certain areas more accessible due to topography and well location. Water supply and equipment (infrastructure) requirements will be the key to economic development of new plays in the Appalachian Basin. Challenges to shale gas development in Appalachia include: water supply and disposal, perforation strategies, drilling technology, and availability of qualified crews for fracs and flowback due to safety concerns.

Geology and History of the Antrim Shale Gas Play, Michigan Basin, USA - William Harrison

The Antrim shale subcrops in a broad band across the upper part of the Michigan Basin and in a narrow band in the lower eastern portion of the basin. Antrim gas was first identified as a nuisance in development of Niagaran pinnacle play wells. However, gas wells in the Antrim, located in the northern part, have been producing since 1986, and by 2007 over 9,000 wells had been drilled. Horizontal drilling in the Antrim started in the early 1990s. Cumulative gas production through 2006 had reached 2.5 Tcf. Completion technologies started with open hole, but wells are now cased and selectively perforated through spot acid. Multi-stage fracs are the rule, using nitrogen foam and sand.

The Lachine and Norwood members of the Antrim are the highest producing zones. Optimum pays zones identified for stimulation are15-22 ft thick. The Norwood member responds to selective perforation and light sand nitrogen fracs. Optimal intervals in the higher Lachine pay are selectively perforated, and either a single or multi-stage sand nitrogen frac is performed. Dewatering of the gas is accomplished at the facility, typically using glycol treatment. Each Antrim project injects formation water into a single salt water disposal well in the underlying Devonian carbonate Dundee Formation or the Detroit River Formation. Gas is sent to large CO_2 removal facilities to reduce the 5-30% CO_2 in the Antrim gas prior to sale.

Vertical depth of Antrim wells ranges from 600-2,000 ft. One of the challenges to drilling in the Antrim is a Michigan state requirement to surface case all wells to 100 ft below the base of the Glacial Drift to prevent contamination of the fresh water aquifer. Horizontal wells comprise only 1% of the wells to date, but new directional drilling techniques are demonstrating drainage of areas with restricted surface accessibility.

The Upper Devonian Antrim Shale is a major gas producer in the Michigan Basin. Estimated ultimate recovery from the current northern Antrim Play is around 5.0 Tcf of gas. The Antrim is a classic black shale that produces natural gas by desorption processes into a complex network of fractures. The distribution of total organic carbon and natural fractures are keys to good productivity.

Geology of the Devonian New Albany Shale, Illinois Basin - Christopher Swezey

The Illinois Basin is a deep sedimentary basin filled with Paleozoic marine and clastic deposits that resulted from the epicontinental sea that covered the area for most of the Phanerozoic. Sea level changes and glaciations caused multiple formations to develop in the basin. The New Albany shale formed in the Devonian and Mississippian as a thick black shale covering much of today's southern Indiana and Illinois and western Kentucky to a depth of 4,500 ft. The New Albany outcrops in a thin band from southeast Indiana northward to northwest Indiana and northeast Illinois and again on the western border of Illinois. A number of cross sections and isopach maps show the distribution and thickness of the New Albany shale.

The New Albany is divided into several members of laminated shales varying from brown, black, and gray to green. The upper and lower members contain calcareous shale and carbonate beds. The New Albany Shale is the distal portion of the Devonian Catskill sandstone and siltstones and is equivalent to the Antrim Shale in Michigan.

Interpretations of depositional environments range from deep to shallow water. In the Illinois Basin the New Albany Shale has long been known as an excellent petroleum source rock, but has only been recently looked at as a reservoir rock. The New Albany Shale is the source of 98% of the oil and natural gases produced from conventional reservoirs in the Illinois Basin from Silurian- through Pennsylvanian-age reservoirs. The central-south part of the basin entered the oil window during the Pennsylvanian-Permian period of maximum burial. In the north and northeast margin of the New Albany the rocks are thermally immature and do not produce gas. Glacial meltwater migrated into the Devonian shales during the Pleistocene and increased hydraulic gradients. The resulting reaction enhanced microbial methanogeneses and generated natural gas along the basin margins. The biogenic gas can be analyzed using radiometric dating and isotope chemistry to show that the present salinity pattern in the Illinois basin was established since the Last Glacial Maximum. The low topography gradient, low permeability of Quaternary glacial till and the overlying Mississippian shales have prevented the biogenic gas from migrating away from its area of generation through meltwater flushing and recharge.

The first natural gas from the New Albany was produced in 1890. Gas has been produced from zones as shallow as 400 ft. Gas fields are concentrated in the western Indiana region. Gas production from the New Albany Shale is associated with naturally occurring enhanced fractures, and has proved difficult to extend because the fracture density is much less beyond the immediate area of production. Natural fracturing is considered essential for reservoir permeability in the New Albany Shale. In most of the basin, reservoirs which overlie high porosity carbonates produce high volumes of water with related disposal problems. However, in western Kentucky, water production from reservoirs overlying low-porosity carbonates is much lower. The natural gas potential for the New Albany Shale in the Illinois Basin is significant, but there are production challenges.

Commercialization of Biogenic Gas from Antrim and New Albany Shales - John Hunter

A brief overview describes the similarities and differences in the Antrim and New Albany shales. The Antrim is a cross-fractured, water-filled natural fracture system. The New Albany is a unidirectional natural fracture system containing free gas. Estimates of the gas resource for the Antrim Shale are 35-76 Tcf and for the new Albany Shale 86-160 Tcf. At this time, drilling and production from the Antrim Shale is highly active, while the New Albany is still under development. A comparison of the reservoir characteristics of the two shales suggests major differences in the natural fracture network. The Antrim has two sets of low-angle fractures, trending in NE-SW or NW-SE directions. The New Albany has one set of large vertical fractures orientated East-West. Fracturing is much more limited in the New Albany than the Antrim. The Antrim has low anisotropy with a typical permeability ratio of 1:1, while the New Albany has a wider anisotropy range with higher average ratios of 20:1.

These differences suggest different drilling and completion strategies. In the Antrim vertical wells are normal with horizontal wells being applicable only in areas of difficult terrain or areas that have restricted surface access. In the New Albany vertical wells are preferred in shallow areas, but horizontal wells generally provide the optimal drilling in the deeper parts of the Illinois Basin. Drilling methods in the New Albany avoid plugging of natural fractures, and wells are completed open hole with no stimulation. Drilling and pump placement must be optimized for water removal and reduction of back pressure. For the Antrim completion methods include over 300 perforations per vertical well, stimulation via a 3-stage frac using a low gel guar-borate system, and diversion techniques to reduce water problems. A number of specific production and infrastructure methods and procedures are illustrated, stressing low pressure, separate gathering systems for gas and water. Low pressure systems result in a significant reduction in capital expenditure, increased production rates due to reduced back pressure on the wells, extended commercial life of the wells and optimization of facilities. Production data from the Antrim Shale is available from the Michigan Department of Environmental Quality. New Albany Shale production data are not available publicly at this time. The Antrim shale has produced commercial quantities of biogenic natural gas for 20 years. The New Albany Shale has vast resources, but technical challenges have hindered economic development. Currently horizontal drilling for biogenic gas shows promise.

Geochemical Evaluation and Comparison of Eastern USA Gas Shales to Other Shale Gas Systems in the USA - Dan Jarvie

Key points to consider in the development of shale gas are the value of Total Organic Carbon (TOC), the importance of thermal maturity, the importance of kerogen type and the importance of residual oil saturation. An understanding of gas types; biogenic -generated by metabolism of organic constituents, and thermogenic - generated as a result of heating processes, is critical. Gas sampling techniques and the need to obtain and preserve high quality cuttings and samples for gas and rock analyses are important so that thermal maturity can be accurately measured. TOC provides information on the type of carbon, porosity and thermal maturity, and it provides for absorption and storage of adsorbed gases. Gas flow rates increase with higher thermal maturity in thermogenic gas. Thermogenic gas tends to be found in older, more mature Paleozoic and Mesozoic basins from north Texas to the Appalachians. Biogenic gas predominates in the Cenozoic basins of the Rocky Mountains. Geochemical evaluation of shale gas systems requires determination of TOC and thermal maturity. Gas shale flow rates appear to be a function of organic richness and thermal maturity with the highest gas flow rates coming form moderately high thermal maturity shales.

CONCLUSIONS

The workshop provided a comprehensive evaluation of gas shale deposits, drilling and completion technologies for the Eastern U.S. Detailed description of shales in the Michigan and Illinois basins are included. The potential for shale gas recovery has been significantly increased in the past decade by discoveries of new drilling and completion technologies. The Barnett shale play has been an inspiration to operators in the Appalachian, Michigan and Illinois basins. Application of these new technologies and strategies in old basins and old fields is revitalizing gas production, and new prospects are being developed every year.

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