DRILLING AND COMPLETION IN THE SHALES OF APPALACHIA

May 29, 2008; Salt Fork Lodge, Cambridge, OH

BOTTOM LINE

The emerging Marcellus Shale play will be the next big Appalachian gas play, especially in the eastern side of the basin where all of the key parameters of thickness, gas content, thermal maturity and natural fractures are optimum. However, this is a high-tech, high-cost play in which science must be addressed up front, and investments must be made in new technologies to drill, log, complete and produce the wells. Cores and data that can be extracted from them also should not be neglected.

Geology is important, especially farther to the west where the Middle Devonian unconformity cuts out rocks above and below the Tully Limestone, such that whereas the Marcellus Shale conformably overlies the Onondaga Limestone in the east, to the west, in Ohio, eventually the black shale on the Onondaga is the younger Rhinestreet Shale; the Marcellus is absent.

The Tully Limestone above and the Onondaga Limestone below create fracture barriers that can keep induced fractures in the Marcellus and overlying Hamilton shale beds. Thus, mapping the extent of the Tully Limestone is another key when entering this play.

Other issues to be addressed are infrastructure and water management, especially in the easternmost part of the play where no wells have been drilled before and local residents and officials are not familiar which the natural gas industry.

PROBLEMS ADDRESSED

The successful exploitation of natural gas resources locked in various Devonian shales requires a better understanding of the shales as reservoirs and the various techniques that have been used to complete shale wells, and an assessment of the relative success of those techniques. Ultimately, new techniques may need to be imported and exploited to achieve success.

TECHNOLOGY OVERVIEW

This workshop was organized to present the newest drilling and completion technologies being applied in the Appalachian basin, with an intended emphasis on horizontal completions and multiple zone completions in the thick Devonian shale section.

PAG member Greg Mason recruited eight speakers, in addition to himself, to address numerous shale-related issues that are critical to the development of our shale gas resource.

The leadoff speaker was Bill Zagorski (Vice President, Range Resources) who changed the title of his talk slightly in order to focus on "Emerging Shale Gas Plays in the Appalachian basin." He began with this warning: "If you are involved in shale, expect your life to change."

Zagorski briefly described several historical shale plays, including the Lake Erie play that began in 1821; a Trenton Limestone-Utica Shale overpressured play near the southeast corner of Lake Ontario; the Big Sandy field in eastern Kentucky that was discovered in the early 1900's and became the first truly big shale field in the US; and "hot spots" in the Marcellus and other Devonian shales in New York and Pennsylvania.

He described the Marcellus as the next big US shale play, noting that industry interest was high and that the majors and large independents were all involved. Total organic content (TOC) greater than 10% has been documented over a large area, and much of the area is overpressured, with good thermal maturity. 3-D seismic is being shot, and a horizontal drilling play is emerging. These wells require very large water-based frac jobs to be effective, which is becoming an environmental problem.

The Marcellus is thicker and more mature, even over mature, to the east; TOC increases to the west. The thickest shale area is in northeast Pennsylvania near the New York line, where the Marcellus also is at a relatively shallow depth. These factors have made this a prime area for exploration.

The Tully Limestone provides a convenient upper frac barrier, and the Onondaga Limestone is a lower frac barrier. Mud logs indicate gas in gray Hamilton-age shales above the Marcellus which have become a second target in the play. The Marcellus is high in quartz content, and SEM work indicates that pores have developed in kerogen-rich beds as well.

In addition to the Marcellus Shale play, Zagorski also described an emerging Trenton Limestone-Utica Shale play in northern New York and a deep Utica-Point Pleasant Shale play that could be the source of much of the gas in the Trenton-Black River play.

Keith Bartenhagen (Schlumberger) discussed "Shale gas evaluation techniques: data integration with completion design." He described the shales as poor reservoir rocks, with very low permeability, in which the gas is adsorbed in the organic-rich beds, with some free gas in fractures. The shales differ in their properties, so operators need to adjust their completion techniques accordingly. The Appalachian shales exhibit common traits with all shale plays: abundant gas in place (40-500 Bcf/section); low recovery efficiencies (8-12%); large economies of scale; fracture stimulation being necessary; and long well life.

He described these evaluation needs: delineate where the shale beds are present; quantify their gas content; determine their producibility; and predict the production performance using field studies and simulation. He then described a shale gas log, and how to solve for kerogen, convert to TOC, and then use isotherms to convert to gas in place (GIP). This conversion requires core analysis, beginning with solving for clay content. Eventually, the process results in three curves for adsorbed gas, free gas and total gas, all in SCF/ton, which can be converted to Bcf/section.

Currently, horizontal completions are twice as expensive as vertical completions, but yield 3 to 4 times the production. Optimal length and orientation are still issues to resolve. FMI logs, dip angle and direction, and gas content logs are used to define a target zone, which must have the appropriate TOC, maturity, fractures, etc, in which to locate the horizontal well. Natural fracture patterns are used to orient the horizontal section, which could be either parallel or perpendicular to the main fracture set.

Keene Weaver (Triad Resources) described "One operator's experience in the Marcellus Shale." Their interest began when they noticed a 70-80 foot thick section of Marcellus with high organic content and good resistivity as they drilled to deeper Clinton-Medina targets. They also noticed similar log characteristics in Barnett Shale wells, so they began a reservoir characterization study of the Marcellus. Their first field test was in a re-completed Oriskany well, which yielded good results following a 3000 bbl water frac. The next step was to drill a new Marcellus well, which had an initial open flow of 6000 Mcf.

The second year of the program saw them drill 10 wells, followed by 15 more in year three. During these two years they noticed that increasing the amount of water in a frac job definitely increased gas flow. Their earliest wells tested in the 175 to 200 MM reserve range; later wells were in the 300 to 350 MM range.

They recommend that you use a mud logger to note gas shows and run a good suite of logs that should include resistivity and ELAN in addition to the typical logs. They suggest that operators core if possible; if not, then run an FMS log.

In a Roane County, WV project, they ran into a lack of pipeline capacity due to high gas flow; water and bacteria problems; early fluctuations in productions due to frac water production; fracture issues; tortuosity due to microfractures; the correct orientation of fractures; and West Virginia permit issues (a deep well permit was required if they were to run an adequate log suite).

In spite of this, they concluded that: the gas resource is in place; pipeline capacity and take away control the speed of development; infrastructure is an issue, along with water, which must be managed; most production comes from the top few feet and the bottom few feet of the Marcellus, leading to a dilemma in horizontal well placement; coiled tubing speeds cleanup and cuts cost; and the Marcellus is the play of the future in the Appalachian basin.

Joe Morris and Jim Pancake (Equitable Production Co) described the "Geology and development of Devonian shale in eastern Kentucky." Their focus was on the historical and current development of the Big Sandy field, but they expanded their talk to include the Cleveland, Upper Huron and Rhinestreet shales, in addition to the Lower Huron Shale, the main pay in the field.

The Big Sandy field contains two structural highs, with an embayment between, over the Rome Trough. TOC trend in the Lower Huron Shale is southeast-northwest over the field, and is the same for the younger Cleveland Shale. However, two trends in TOC are evident in the deeper Rhinestreet Shale. Thermal maturity increases to the southeast into West Virginia. Play extent maps for the various shales are based on TOC and maturity.

Equitable is using nitrogen fracs as they extend the field to the east and west, away from the historical "sweet" spot. They are completing multiple pays in the Cleveland, Upper Huron and Lower Huron. A bottom hole pressure map is used as a completion guide. A foam frac is used where the overlying Berea Sandstone is fractured and pressure is high. The Berea and the Mississippian Big Lime are uphole, secondary targets.

Historical estimated ultimate recoveries (EUR) average 640 MMCf; wells being developed now average only 443 MMcf. Horizontal wells are being drilled to increase recovery. Equitable uses TOC and vitrinite reflectance (thermal maturity) maps to locate horizontal wells, and the maximum stress and induced frac direction (NE-SW) to orient horizontal wells. They consider both options - transverse, perpendicular to induced frac trends, and longitudinal, parallel to induced frac trends – but prefer to drill in a NW-SE direction.

Equitable attempts to avoid communication problems by using a 200 foot minimum interval between horizontal laterals when completing more than one shale interval in the same location. Microseismic studies indicate a NE-SW cloud as induced fractures parallel natural fracture trends. Initially, Equitable drilled 1800 foot laterals, but are now up to 3000 feet. The speakers cited an example where they re-entered an old 5 MMcf/day vertical well, kicked off to drill horizontally in the shale, and tested an 880 Mcf natural flow.

The speakers also addressed the significance of the Middle Devonian unconformity that removed section between the Rhinestreet and Onondaga, such that the Rhinestreet rests unconformably on the Onondaga. When horizontal wells were drilled in the Lower Huron and Rhinestreet, they noticed a problem with sour gas in the Rhinestreet. This may be caused by the unconformity cutting down into the carbonate section, such that the Rhinestreet is actually resting on the Upper Silurian Salina section, not the Onondaga.

The speakers concluded that: completion technology will continue to evolve; and horizontal drilling, infill drilling and extension drilling will be important in the future.

Doug Walser (Pinnacle Technologies) discussed "Utilizing microseismic deliverables in the Marcellus and other Devonian mature shales." Fracture mapping involves mapping the length, height and azimuth of induced fracture sets. This is important in positioning horizontal wells in such a way as to avoid early well communication, and avoid leaving gas reserves behind in undrained areas. Flow into wells is linear at first, but transitions into radial with time, resulting in oval drainage areas parallel to fracture trends.

Operators commonly consider total organic carbon, or TOC, and thickness of organic-rich black shale, or h, when they evaluate a prospect. However, the speaker warned that for every combination of TOC and h there is a unique minimum value of thermal maturity in commercial projects. TOC and thermal maturity can be measured in the lab; thickness from a well log. However, when all three values are in the acceptable range, one still must have natural fractures present, or planes of weakness that “snap” when you change the stress field during a frac job. This is common to all successful shale plays.

What else can kill your shale project? Measureable free water above, in or below the pay zone; excessive depth (increased cost) to the pay; and excessive frac gradient (except in shallow plays) all can kill your play. A lack of adequate infrastructure also can kill a borderline prospect.

Walser suggested keeping frac fluids simple and low in viscosity; slickwater fracs for the Marcellus, foam or nitrogen for the Lower Huron, fluids and jobs that will increase the stimulated reservoir volume, or SRV. Smaller proppant size, which will allow proppant travel farther from the well bore, the speed of completion, and stress shadowing all will increase SRV.

Before entering a shale play, the operator should perform the science up front. This is a high dollar cost item; shale plays “are not for the little guy,” according to the speaker. Vertical wells should be drilled and science done prior to drilling the first horizontal well.

The Marcellus play area may be twice the size of the Barnett play size, but the Barnett is twice as thick, so the plays may be equal. However, in spite of the abundant acreage, the Marcellus still is a risky play, and cost effective strategies should be employed. Operators should not “poor boy” their approach by using existing well bores from which to drill a horizontal, or for recompletion. No horizontals should be drilled until one knows the geochemical and lithologic parameters, proximity to water-bearing zones, far field induced frac azimuth, and height growth information from microseismic technology.

The speaker continued to emphasize that science should be conducted up front to accelerate the learning curve and save money in the long run. Investments in 3-D seismic, full log suites, geochemistry and fracture mapping also were recommended. Vertical well pilots should be drilled and completed, with and without proppant, and then tested for production. Multiple wells should be drilled across your acreage. Finally, he warned attendees to guard their secrets until all leases were gone, and not to “toss the Barnett Shale guys out the window.”

In his summary, he stated that any one of these parameters – thickness, TOC or thermal maturity – can be lacking if the other two are outstanding; natural fractures or planes of weakness must be present; and only a very few processes are repeatedly commercial.

Kevin Smith (Columbia Gas Transmission) addressed the group on “Recompletion techniques in the Devonian of southeast Ohio.” He began with a confession, saying that based on what the previous speaker had said, he had been doing the exact wrong approach by poor-boying plug backs. Why? Because of the high lease costs ($2000/acre) in the Marcellus play it was cost efficient to look at what you already have first.

With this in mind, he evaluated an old project based on the demise of Section 107 tax credits for tight sands. He needed to test the project quickly, cheaply and safely, so he developed a model to stimulate the sands from the Gordon up through the Berea. Casing below the Gordon (from 200’ below the Gordon to TD) was pulled and inspected, and re-used if it was up to standard. Two-stage frac jobs were performed on the Gordon, Gordon Stray and Thirty foot, then the Berea.

Greg Mason (NGO Development), the workshop coordinator, wrapped up the session with a discussion of “Why shale, and where have you been?” His interest was in evaluating the Marcellus in his area of operation, where the shale is only about 3000 feet deep. The current climate in Ohio makes shale worth looking into again, but not all of the factors that are favorable to the east are as favorable in Ohio. Thermal maturity values indicate that the shale has not gone through the oil window, so the gas may be biogenic, or thermogenic gas that has migrated from farther east.
He went into an explanation of Liz Rowan’s paper on thermal maturity in the Appalachian basin, based on three cross sections from Ohio into West Virginia. These cross sections illustrate the migration of thermal maturity of Devonian and Ordovician shales units through time from pre-oil in the west, to oil, and then gas, to the east.

NGO Development owns an old Clinton field, and logs from those wells indicate the presence of gas in the Lower Huron Shale. NGO cored from the Berea to the Onondaga and sent samples to the lab for a complete mineral analysis. Data from the lab was then used to correlate the well logs. Finally, the Lower Huron was perforated and fractured in the new program.

What was learned? First, use OPM (Other Peoples’ Money), learn something about the source rock and geology, work with the vendors, and then take the risk.

CONNECTIONS

The above observations were based on a workshop sponsored by PTTC’s Appalachian Region at the Salt Fork Lodge, Cambridge, OH on May 29, 2008.

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