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Producing Gas from Shales

A rock as tight as a table top, the Barnett Shale has become the most prolific gas reservoir in Texas and the largest active natural gas play in the United States. Exploration in this play is truly cutting edge, pioneering stimulation technology that will undoubtedly lead to new shale gas production throughout the world.

Thomas Smith, Associate Editor

The Barnett Shale play, in the Fort Worth Basin of north Texas, is currently producing about 1.65 Bcfpd gas (47 MMm³ per day) from over 5,600 wells. There are close to 150 rigs actively drilling at the current time to complete the nearly 3,000 permitted wells for this year. The play could eventually cover over 15,000 km² and has a potential mean volume of over 27 Tcfg (0.76 Tm³) (U. S. Geological Survey (USGS) estimates), making it the second largest gas play discovered in North America. Richard Pollastro of the USGS says "these estimates were determined from vertical well production. A reassessment using horizontal well data could raise these estimates considerably."

In the Beginning: Slay #1

The pioneering efforts of Mitchell Energy in the early 80's made this play possible. While drilling for conventional oil and gas resources, geologists and engineers began looking at the Barnett Shale and saw similarities to the productive Devonian shales in the Appalachian Basin. After several fracture attempts that resulted in minor gas flows, the interval was stimulated with 210,000 pounds of sand and Slay #1 was completed as the first Barnett gas well.

Mitchell Energy Corporation was first to test the interval in 1981, but it took many years and a stubborn persistence before its potential was realized.

Throughout the 50's and 60's, the Barnett Shale was thought of as spent source rock encountered when drilling to other objectives. USGS studies show this shale to be the primary source for nearly 2 Bbo (320 MMm³) and 8 Tcf (280 Bm³) of gas produced from conventional reservoirs in the Fort Worth Basin area.

Dan Steward, now with Republic Energy, was there from the first tests of the Barnett and through the learning stages of how to produce it. "The Slay well was drilled as a Viola Formation (directly underlies the Barnett) producer. It turned out tight. Mr. Mitchell had always wanted to test



The Barnett Shale and other potential shale gas plays in the US.

the Barnett which directly overlies the Viola," says Dan. "We started out with small fracs and poor results. It took 36 wells and increasingly larger fracs before we could say we had anything commercial. Most companies would have given up on the play, but Mitchell was well positioned in the area and looking to replace declining production with new prospects."

Growth of Completion Technology

Between 1981 and 1989, only 66 wells were drilled to evaluate the Barnett. Early stimulation used in these wells progressed from small CO₂ or N₂ fracture treatments to large gel fracs. consisting of 400,000 gallons of water and 1,250,000 pounds of sand. This system had a theoretical half-frac length of 450 m. The results were variable with wells producing up to 1 Bcf (28 MMm³) ultimate recovery. According to Bill Grieser of Halliburton: "At first we were concerned about using fresh water in a shale formation. Everything we had learned up to that time was that shales and water do not mix: we assumed all shales were alike. Now, we are finding out that every shale is unique".

Early in 1997, Mitchell Energy tried the first "slick-water frac" in the Barnett also called a light sand frac (LSF) that used 800,000 gallons of water along with 200,000 pounds of sand. This style of frac was borrowed from similar style jobs which were starting to be used in the Cotton Valley Sandstone of East Texas. "The light sand fracs were originally done out of a need to get the economics in line (gas prices were at historic lows) rather than research," says Bill Grieser. Microseismic mapping (explained later in this article) indicated that the LSF outperformed the conventional gel frac. system. Refracs of older producing wells also proved worthwhile in enhancing production and have become routine.

Horizontal drilling started in earnest in 2002 after Devon Energy acquired Mitchell. About 1500 horizontal wells will be drilled this year alone. These wells increased production twofold, slowed decline rates, and extended the play beyond the core producing area.

This core area has the Marble Falls Limestone as an upper frac barrier and the Viola Limestone for the lower frac barrier. Outside the core area, the Viola Limestone pinches out to the west and southwest. In the areas where the Viola is absent, vertical wells have had limited success because many have frac'd into the underlying Ellenburger, opening a conduit for water production. Horizontal drilling technology, combined with area specific frac treatments, have mitigated this problem and expanded the play into previously noncommercial areas.

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Complex Fracturing

The classical description of a hydraulic fracture is a single biwing planar crack with the well bore at the center. However, evidence gathered from microseismic mapping indicates that fractures in the real world are almost never that simple.

"The Barnett success has caused a new look at the Appalachian Basin and other , shale gas plays. Areas that had previously been passed by are now being revaluated with larger Barnett type stimulation treatments and found to be productive." Dan Steward, Republic Energy

Mapping has proven that a fracture treatment in the Barnett can be very complex. Fracture mapping technologies can provide insight into reservoir depletion dynamics and significantly help optimize reservoir management.

Studies using these mapping techniques illustrated that fractures in the Barnett grow in a complex network. The cumulative fracture network length, not the conventional fracture half-lengths, control gas recovery and reservoir patterns. Kevin Fisher, President of Pinnacle Technologies says "the Barnett permeability is so low that the drainage radius from any single fracture is likely only 10 or 20 feet (up to 6m). Because of this ultra-low permeability, a huge surface area is necessary to provide adequate

Geology

At first glance, the Barnett Shale may seem simple in terms of structural and stratigraphic complexity. However, geoscientists and engineers have gone to great lengths to understand the geology and geochemistry and their impact on successful production from the interval. Geological factors affecting ultimate reserves are the maturation pattern throughout the basin, regional faulting, underlying Ellenburger karsting and the thickness of the Barnett in the prospective area. Drilling, fracture stimulation techniques and completion strategy must be designed to match the needs of a given area.

The Barnett Shale is an organic-rich marine shelf deposit of Mississippian (Lower Carboniferous) age. It unconformably overlies the Ordovician Viola Limestone-Ellenburger Group and is conformably overlain by the Pennsylvanian Marble Falls Limestone. In the Fort Worth Basin, the Barnett ranges from 60 m thick in the southwest portion of the Fort Worth Basin to 300 m in the northeast portion. The core field area averages 150 m in thickness.

Composition is 2-8% organics, 20-30% clay minerals (illite), 45-55% silt (quartz and feldspar), and 15-19% carbonates (calcite and dolomite). It is also characterized by extremely low permeability, ranging from 0.000009 to 0.005 mD and 3.5% average porosity.

Wells drilled on or near faults tend to have high fracture gradients. Near major tectonic faults, water production is a problem when well stimulation fractures migrate toward the fault and into communication with Viola or Ellenburger water. Another problem that results in poor frac treatments is karsting in the Ellenburger creating faulted chimneys up through the Barnett. 3-D seismic surveys image those areas that should be avoided with current stimulation procedures and when that is not possible, cemented off.



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contact with the reservoir to profitably drain this resource. So while fracture complexity can be detrimental in some reservoirs due to restricting the abil-

ity to place proppant, in the Barnett this complexity is actually favorable to be able to increase production rates."

Fisher also says the Barnett wells can benefit from refracs, potentially even several refracs, because

of the aforementioned small drainage radius. "A refrac can create a higher

density fracture network (new cracks in between old cracks), thus increasing fracture surface area."

Looking to the Future

Organic rich shales have always been looked at as source rocks. Under the right conditions, oil and gas can be generated from these shales and migrates over time into reservoir rocks. Every petroleum system owes its existence to the presence of source rocks and now many of these

Surface tiltmeter arrays measure surface deformation. The downhole tiltmeters measure deformation patterns in adjacent well bores. Sensitive geophones measure micro-earthquakes caused by the fracture treatment.

Shale Gas

Shale gas production has been around for a long time, in fact, the first commercial well was drilled in New York in the late 1820's. By 1926, the Devonian shale gas fields in the Appalachian Basin were the world's largest known occurrence of natural gas. These shales extend from southwestern New York south to eastern Kentucky and central Tennessee with the largest fields found in Kentucky and West Virginia. Shale gas exploration and exploitation has continued to grow aided by tax incentives in the 1980's. These incentives have expired, but operators have continued to expand gas shale programs. This year, shale gas production in the US could approach 1 Tcf (28Bm³), although exact numbers are difficult because the play is evolving at a rapid rate. Gas in place estimates total 581 Tcf (16 Tm³) and the recoverable resource estimates range from 31 to 76 Tcf (0.88 to 2.1 Tm³) and will probably go up as these plays develop.

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Grieser of Halliburton.

source rocks are becoming productive

Dan Steward put it this way: "10 years

ago, if you ask 100 geologists what makes a viable shale play possible it would be having an open, natural fracture system present. Now, after the Barnett experience, industry has found that fractures can be induced to produce economic gas. Simply put, it redefines our exploration model for shales. We are still learning and just about any area may be productive."

Special thanks to Bill Grieser and Katy Eichelberger of Halliburton, Kevin Fisher of Pinnacle Technology, Dan Steward of Republic Energy, and Richard Pollastro of the USGS.



Shale gas reservoirs store natural gas as free gas within the rock pores and natural fractures, and as absorbed gas on organic material. The speed and ultimate gas production is affected by these storage systems. The challenge in exploring shale gas plays is in obtaining economic production rates. Because shales are typically low to very low in permeability, fracture systems that exist naturally or are induced within the reservoir are necessary to sustain gas production. Some type of stimulation is required to get most wells to produce in commercial rates.

The real upside of shale gas plays are long-lived reserves and high success rates with attractive finding costs. New stimulation technologies will continue to expand the productive limits of historic play areas and add to the already impressive resource estimates.