

Special techniques tap shale gas

For maximum production, look at the life of a shale-gas play.

AUTHORS

Matt Blauch and **Bill Grieser**, Halliburton

Operators producing gas from shale reservoirs can help ensure success by following the five life-cycle phases of project development and proper application of knowledge and technologies in context with each project phase. Significant value creation can be achieved by careful and innovative use of appropriate technologies and shale knowledge available today.

The life-cycle phases are:

1. **Reservoir assessment.** Evaluate shale and reservoir potential.
2. **Startup exploration.** Experimental drilling and trial investigation of fracture design and production prediction.
3. **Early development (mass production).** Rapid development using an optimized design. Database development and benchmarking.
4. **Mature development (reserve harvesting).** Cash-flow cycle; reservoir production-history matching; adjustment of reservoir model; database imaging.
5. **Declining phase (maintenance and remediation).** Identification of remedial candidates; restimulation; decline-curve shifting.

Production-enhancement technology processes applicable to shale-gas reservoirs:

- Prospect evaluation and core testing.
- Shale lithotyping to determine key characteristics of productive shale.
- Log data integration and analysis specific to shale.
- Designing and drilling the vertical and horizontal well for

stimulation.

- Proppant size and loading considerations.
- Optimization and tailoring water-frac fluid chemistry to the shale.
- Remedial treatment processes for obtaining long-term sustained production.

Prospect evaluation

Usually, the first step in the design and application process is to evaluate the shale prospect. Initially, both 2-D and 3-D seismic readings are processed to determine the extent of the shale play. The volume of shale is estimated in tons per acre (ton/acre-ft). Gas in place (GIP) is calculated from the geochemical determination of standard cubic feet per ton (scf/ton), as follows: $GIP = (\rho) (1359) (scf/ton) = scf/acre-ft$.

Shale samples collected from various sources help in determining the commercial viability of the project. Factors include:

- Shale hydrocarbon content (scf/ton, bbl/ton, GIP);
- Shale maturity;
- Kerogen type (Types I and II, oil; Type III, gas);
- Shale porosity, permeability, oil, water and gas saturations; and
- Shale desorption constant or gas isotherm.

Productive shale formations

In general, a productive shale formation includes these characteristics:

- Zone thickness of >100 ft (30.5 m);
- Well bounded, and containing hydraulic fracture energy;
- Maturation in the gas window: $\rho = 1.1$ to 1.4;
- Good gas content > 100 scf/ton;
- High total organic content (TOC) > 3%;

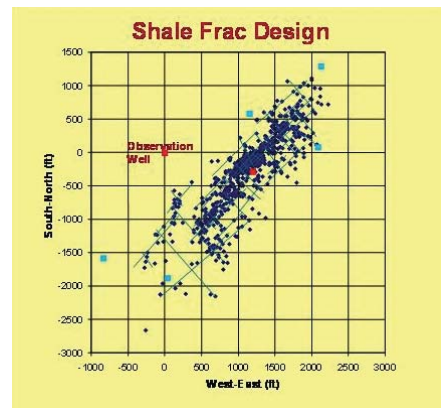


Figure 1. Microseismic fracture mapping reveals the complex network of fractures created in shale reservoirs by fracture stimulation. (Images courtesy of Halliburton)

- Low hydrogen content;
- Moderate clay content < 40% with very low mixed-layer component;
- Brittle composition, as indicated by a low Poisson's Ratio and a high Young's Modulus;
- Combination of rock fabric and reservoir and lithology features that enhance gas producibility; and

(Shale evaluation tests are shown in Table 1.)

Log data requirement

A triple-combo log can be used to obtain density, gamma ray, resistivity, neutron and density porosity. A wave-sonic log should be run to obtain mechanical rock properties. An electromagnetic imaging (EMI) tool should be run to obtain natural and induced fracture direction, followed by analysis to identify sweet spots and a fracture-initiation site.

Enhancing production from shale

Re-stimulation has proved to increase recoverable reserves by 50 to 100%.

Table 1. Suggested minimum sample testing suite.

TEST	OUTPUT	
TOC	Total organic carbon content (> 3% desirable)	
Kerogen-type plot	Hydrogen:carbon ratios to oxygen: carbon ratios (Van Krevelen diagrams).	
Shale maturity	Vitrinite reflectance <i>r</i> , indicating what hydrocarbon phase is most likely to be produced.	
	Rho %	HC-Type
	0-0.55	onset of oil generation
	0.55-0.9	peak oil production
	0.9-1.1	wet gas
	1.1-1.4	dry or wet gas
	1.4-2.1	dry gas only
	>2.1	CO ₂
Gas or oil content	scf/ton or bbl/ton	
Gas content	free and adsorbed gas content and diffusion content	
X-ray analysis	mineral makeup by weight of sample. Interpretation of data along with lithology information leads to selection of the optimal base fracturing fluid water chemistry and reactive fluid design.	
SEM photos	photomicrographs showing shale before and after effects of the fracture surface following contact with treating fluids	
Mechanical properties	Young's Modulus and Poisson's Ratio, measuring shale ductility or brittleness. In general, more brittle shale indicates that the shale can generate a large "fracture fairway."	

Future vertical and horizontal wells are likely to be completed incorporating the capability to selectively treat, isolate and re-treat unstimulated areas along the vertical/horizontal well bore.

Stimulating vertical wells

From 1987 to 1997, the fracture design for the Barnett shale formation consisted of crosslinked gel (200,000 gal to 400,000 gal, carrying 500,000 to 2 million lb proppant). In 1998, light-sand fractures were introduced, then evolved into the large, slick-water fracture treatments now prevalent.

Current vertical stimulation designs feature (1) four or five perforation sites, 2 to 4 ft (.6 to 1.2 m) long, (2) 5 shots per foot (spf) and 60° phasing, and (3) pump rates of 1 to 2 bbl/min per perf or 20 bbl/min per initiation site. Volumes pumped are about 2,500

gal/ft, delivering 400 lb/ft of proppant.

In early phases of the life cycle, vertical wells are usually drilled and completed to help the operator characterize the reservoir. With a background of knowledge gained from drilling, fracturing and producing the vertical well, more comprehensive Phases 3 and 4 can be planned and performed profitably.

Stimulating horizontal wells

Current horizontal stimulation designs are typically:

- Two to eight stages per horizontal well bore;
- Two to four frac initiation sites per stage;
- 2 to 4 ft of perforations/site, with 6 spf, with 60° phasing;
- 20 to 30 bbl/min per frac site or 2 to 4 bbl/min per perforation; and

- Volume average 1,800 gal/ft. Horizontal well completions are of three types:
 - Cased, cemented, multistage using composite plugs to separate frac stages;
 - Multistage, using jetted sand/water delivered by coiled or jointed tubing to perforate zones; and
 - Mechanical bottomhole assembly (BHA).

The cased, cemented, multistage completion using composite plugs is the most commonly used type of horizontal completion in shale wells. Each stage is perforated, fracture-stimulated and isolated with a packer or bridge plug, allowing the next stage to be treated. The plugs/packers act as a well "bottom" for fracturing pressure to build up against.

Jet-perforated multistage completions eliminate the need to perforate or set plugs. This service is run on coiled or jointed tubing to the first-stage frac site; perforations and a tunnel are eroded by pumping through the tubing at a high differential pressure, using sand and water as the cutting stream. The fracture initiates and extends at the jet site; packers are not required because the jet velocity causes a pressure drop at the jet exit. The pressure drop pulls fluid from the annulus into the fracture.

Mechanical BHA-type completions have been run in horizontal shale well bores as a new innovative alternative to cementing and perforating. These systems are deployed as part of the production casing and provide mechanical isolation and selective injection sites that can be opened and, in some cases, closed manually.

The most recent advancements have been made in the development of multistage frac-acid tools being applied in both openhole and cased-hole completions with hydraulic-set packers and sliding valves opened by

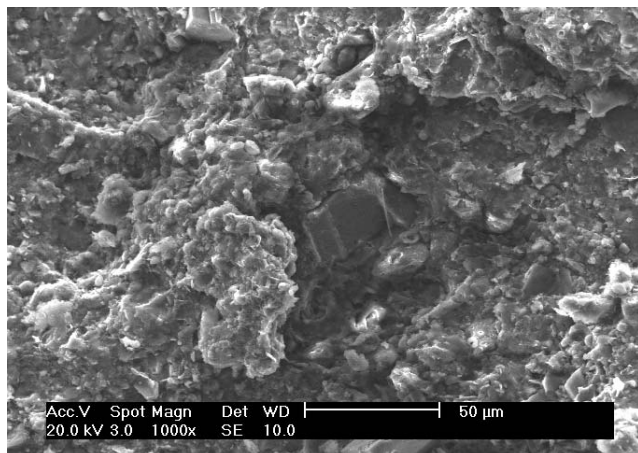


Figure 2. Shale fracture surface shown before reactive fluid contact. Image is taken using an environmental scanning electron microscope (ESEM) at 1000X magnification.

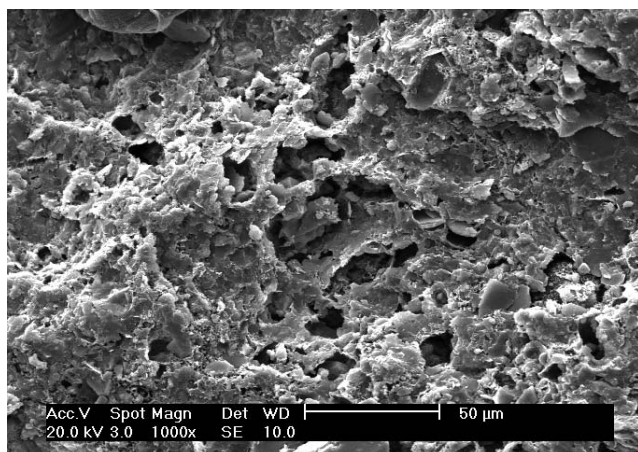


Figure 3. Same shale fracture surface as shown above after contact with a reactive fluid. Result is an increase in effective surface area and enhanced flow channels for gas to diffuse from shale fracture surface into the created fracture void.

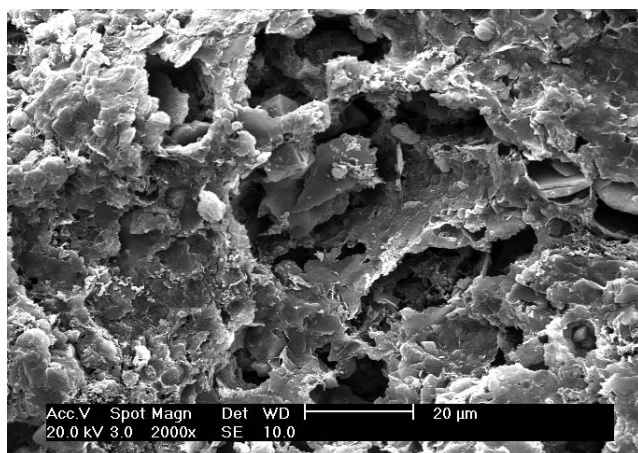


Figure 4. This is a two-fold higher magnification (2000X) image showing detail of the micrograph in Fig. 3.

pumping balls or shifting mechanical devices on jointed or coiled tubing.

Water fracs produce a complex network of narrow-aperture fractures that can be either induced from extensive shear-failures (like shattered safety glass) or created from dilation of pre-existing, incipient fractures or planes of weakness in the shale. The frac width must be $1.5 \pm$ times the maximum grain diameter of the proppant to provide additional propping of the induced fractures. Because the permeability of the matrix rock is usually ultra-low (0.0001 to 0.001 mD), except possibly near the well bore, the fracture conductivity does not need to be high; 20 to 50 mD-ft is sufficient conductivity through the fracture network.

Adaptation and modification of current fracture models calibrated to real-time microseismic mapping are being used to help in the design of stimulation treatments. Fig. 1 is a plot of seismic events showing the complex network of fractures created in a Barnett Shale reservoir by a large stimulation treatment.

Shale water-frac chemistry features application of friction reducers, surface modification agents (SMA), microemulsions, defloculants and reactive fluids. The SMA helps minimize proppant settling, control production of fines and enhance propped fracture conductivity. Microemulsion additives help remove water load and enhance recovery of fracturing liquids, resulting in significant uplift in recovery factors and estimated ultimate recovery (EUR). Friction-reducer defloculants are added to prevent the potential negative impact friction-reducer polymers can have when interacting with formation fines and liquid hydrocarbon.

The use of reactive fluids is a relatively new concept in shale stimulation, evolving from the observation that shale lithologies contain distributed low levels of acid-reactive minerals. In experimental trials of the use of weak-acid reactive systems, the unexpected pressure drops that occur when the reactive fluids contact the shale formation inspired treatments of 20,000 to 200,000 gal of reactive fluid through the frac water. Initial production has been double that of treatments without reactive fluids included. Figs. 2 through 4 show shales before and after being exposed to reactive systems. Early field trials are showing excellent production improvement results.

Refracturing

Vertical shale wells can see production increases of 30% to 80% from reperforation of the original producing interval and pumping a job volume that is at least 25% larger than the previous frac.

Refracturing horizontal wells presents two main obstacles: (1) initial frac sites must be somehow isolated, and (2) new frac sites must be created in areas of unstimulated horizontal well bore. Jetting between original frac sites allows the operator to treat areas of unstimulated reservoir; isolation is accomplished by the Bernoulli force created by the jet tool. **F&P**