Hydraulic fracturing: Overview, trends, issues

By Stephen A Holditch,
Texas A&M University

ONE CAN TRACE the history of tight gas sand exploitation to the 1950s and '60s with the development of hydraulic fracture treatment technology. In the 1960s, natural gas prices and demand were low, thus very few tight gas plays were economic to develop. However, in the 1970s, increased product prices and improved technology for fracture fluids, propping agents and pumping systems led to numerous tight gas plays in South Texas, East Texas, the Mid-Continent and the Rocky Mountains. In the 1980s and '90s, research funding from the US Department of Energy (DOE), the Gas Research Institute (GRI), a few major producing companies and the service companies led to significant improvements in formation evaluation, fracture fluids and fracture monitoring and a better understanding of hydraulic fracturing with the development of 3D and pseudo-3D fracture propagation models.

Currently, with relatively high gas prices, many operators are successfully developing tight gas reservoirs and gas shale reservoirs. However, even with recent successes, new technologies are needed for continued improvement in hydraulic fracturing in both tight gas reservoirs and gas shales.

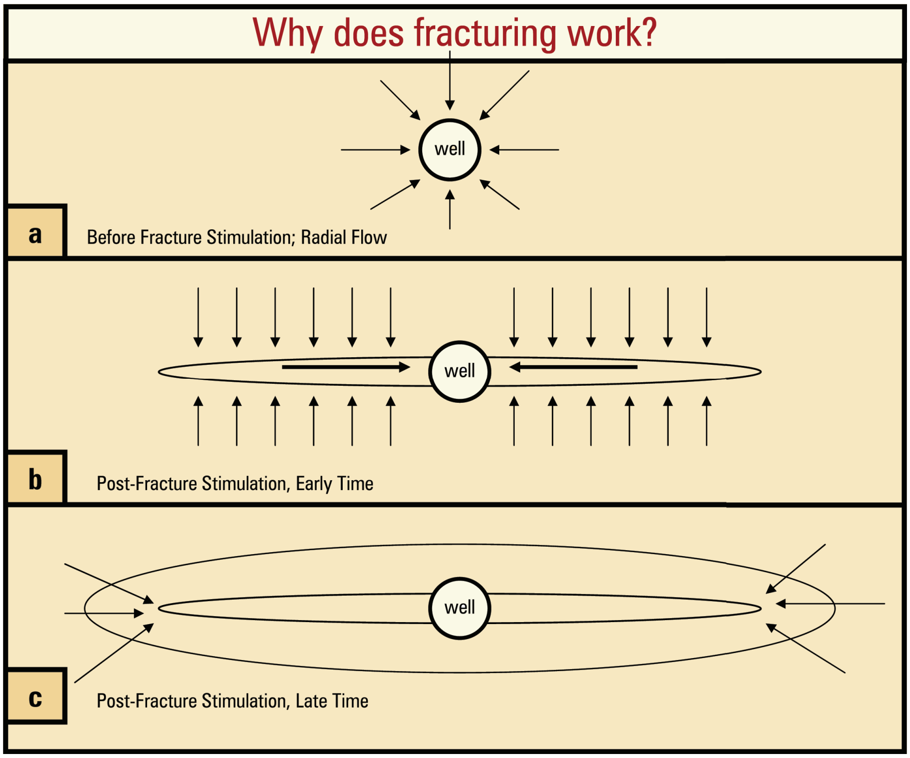

Figure 1: A long conductive fracture transforms the flow path that natural gas must take to enter the wellbore. The radial flow without hydraulic fracturing is seen in 1a; 1b and 1c show gas flow path after a successful fracture stimulation treatment.

WHY IT WORKS

Hydraulic fracture stimulation can improve the productivity of a well in a tight gas reservoir because a long conductive fracture transforms the flow path that natural gas must take to enter the wellbore. Figure 1a illustrates radial flow in the reservoir when no hydraulic fracture has been created. All of the gas must converge radially to a very small area called the wellbore. For a radial flow pattern, most of the pressure drop in the reservoir occurs near the wellbore. Figures 1b and 1c show the flow path of natural gas from the reservoir to the wellbore after a successful fracture stimulation treatment.

At early time, Figure 1b, natural gas enters into the fracture from all points along the fracture in a linear fashion. The highly conductive fracture rapidly transports the gas to the wellbore. At late time, Figure 1c, the gas in the reservoir is flowing towards an elliptical pressure sink and most of the gas enters near the tip of the fracture. Conventional wisdom in designing hydraulic fracture treatments for tight gas sands would suggest that successful stimulation of tight gas sands requires creating a long, conductive fracture filled with proppant opposite the pay zone interval. This is accomplished by pumping large volumes of proppant at high concentrations into the fracture using fluids that can transport and uniformly distribute proppant deeply into the fracture.

Basic reservoir engineering calculations can be used to show that gas recovery and deliverability will be functions of formation permeability, net gas pay thickness, gas porosity, drainage area and propped fracture length and fracture conductivity in the reservoir interval. As the hydraulic fracture length and conductivity increase opposite the pay interval, the well will produce more gas at higher flow rates.

THE RESOURCE TRIANGLE

The target formations for most hydraulic fracturing treatments are low-quality reservoirs. Masters and Gray published the concept of the resource triangle, which states that "oil and gas resources are distributed log normally in nature," just like any other natural resource. Figure 2 (Page 114) presents the concept. At the top are the medium- to high-quality reservoirs. These conventional reservoirs are normally small in size and easy to develop. The most difficult part is finding them. However, as one goes deeper into the resource triangle, one encounters unconventional reservoirs that have large volumes of oil or gas in place but are more difficult to develop. To produce these unconventional reservoirs, increased oil and gas prices and/or improved technology are required.

In the last 30 years, substantial improvements in technology and increases in oil and gas prices have allowed many operators to produce low permeability oil and gas fields, gas from coalbed and shales, as well as heavy oil deposits. Due to the log-normal distribution of natural resources, the volumes of oil and gas that are stored in these unconventional reservoirs are substantially higher than found in conventional reservoirs.

Conventional oil or gas reservoirs are those that can be produced at economic flow rates and that will produce economic volumes of oil and gas without requiring large stimulation treatments or special recovery processes. A conventional reservoir is essentially a high- to medium-permeability reservoir where one can drill a vertical well, perforate the pay interval, then produce the well at commercial flow rates and recover economic volumes of oil and gas. The most difficult part is the exploration, or just finding the conventional reservoir. Once discovered, conventional reservoirs can be developed using conventional drilling, completion and production technologies.

An unconventional oil or gas reservoir is one that cannot be produced at economic flow rates or that does not produce economic volumes of oil and gas without assistance from massive stimulation treatments or special recovery processes and technologies such as steam injection. Typical unconventional reservoirs are tight gas sands, coalbed methane, heavy oil and gas shales. Geologically, unconventional reservoirs are easy to find. They usually cover large geographical areas. However, the best technologies must be used to define the best portions of the resource, often called the "sweet spots." In addition, the best drilling, formation evaluation and completion technologies must be used to produce enough oil or gas to make the resource economic. Wells in unconventional reservoirs produce small volumes per well compared with conventional resources. Thus, per-well profit margins are small.

TECHNOLOGY IN THE 20TH CENTURY

Fracture fluids and propping agents: One major change in hydraulic fracturing over time has been the evolution of fracturing fluids. The first fracture treatment in 1947 was pumped using gasoline gelled with napalm. In the 1950s, the industry began using gelled oil, then progressed to linear gelled water in the '60s and cross-linked gelled water in the '70s. The 1980s saw the introduction of foamed fluids and delayed cross-linkers. In the 1990s, industry began using fluids with advanced breaker technology and reduced polymer loadings trying to minimize damage to the fracture by the polymers. In the future, the industry needs to look at developing polymer-free fluids or fluids with polymers that degrade more completely at temperatures below 250°F.

Fracture propping agents developed even more radically than fracture fluids. The first propping agent was river sand. The industry experimented with walnut hulls, aluminum pellets and glass beads — unsuccessfully. In the late 1970s, **Exxon** patented the use of sintered bauxite, which led to the development of a variety of ceramic proppants in the 1980s and '90s. In addition, resin-coated propping agents were introduced and are now widely used. The design engineer has a wide variety of propping agents to choose from.

PROGRESS IN THE 1990S

Substantial progress in hydraulic fracturing was made in the 1990s in areas such as improved fracture fluids, improved mathematical models, imaging methods that work, and the globalization of hydraulic fracturing. As mentioned, new fluid systems became available as gel loadings were reduced as better cross-linkers were developed, a significant step in reducing gel damage to the proppant pack. In addition, three-dimensional fracture simulators became the common tool for fracture design and analyses. Fracture imaging methods became commonly applied, which led to improved fracture analyses, which affected how reservoirs were developed. Finally, fracture technology was globalized as industry began conducting a significant number of fracture treatments in Venezuela, Russia and the Middle East.

CURRENT CHALLENGES

Even with substantial progress in technology since the 1950s, there is still much to learn and many technologies to develop or improve so that hydraulic fracturing can become even more important to the industry. The following are areas where more work is needed:

• Resource assessment: Better methods should be developed for quantifying the uncertainty concerning the US unconventional gas resource base. We should then be able to extrapolate our knowledge of the unconventional gas resource base worldwide using North America as an analogy. We can also use information in the literature to determine the optimal completion and stimulation methods by basin and formation so that such knowledge can be used worldwide.

• Hydraulic fracturing: The industry needs to develop better fracture fluid mathematical models to simulate filtrate invasion and clean-up in tight gas sands. We still have problems designing fracture fluids (breakers) for reservoirs with BHT less than 250°F. It is often a catch-22. If you put enough breaker in the fluid to break down the polymers at low temperature, it sometimes leads to a screen-out. Conversely, if you leave out the breaker, you can pump the treatment but it may not clean up properly. The bottom line is we still need better fluids for low- to moderate-temperature reservoirs. We also need stronger, lighterweight proppants. There has been some progress with proppants recently. Finally, we can always use better acid fracture model for carbonates, and better fracture models and fracturing techniques for horizontal wells.

• Well completions: One of the toughest problems is how to optimize the completion methods for thick, multi-zone intervals. There are a wide variety of diversion methods, and it is difficult to choose the optimum method. The selection of which zone(s) to complete could be improved if we had better log-core correlations in tight sands and in gas shales. If we had rapid analyses of well performance of tight sand reservoirs, it would help us make better decisions on how to complete and stimulate tight gas wells, especially in horizontal wells.

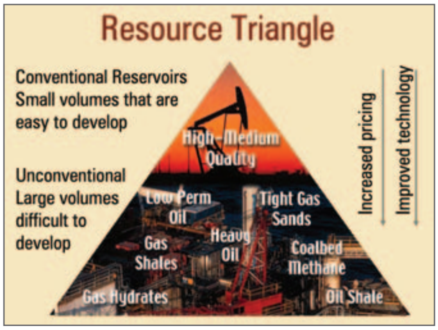

Figure 2: Typical unconventional reservoirs are easy to find, but the best technologies must be used to define the "sweet spots."

• High Pressure-High Temperature (HPHT) Operations: Many agree that HPHT operations is one of our most challenging problems in the 21st century. We can use better measurements of gas properties, a better understanding of drilling mud measurements, cement measurements, and sensors for reservoir monitoring under HPHT conditions. There could also be improvements in issues involved with deep well casing integrity

• General Areas of Research Models: We can also use more technology to understand and develop naturally fractured reservoirs, especially shale gas reservoirs. We need to develop better methods for unloading wellbore liquids in low-rate gas wells. General benefit to all parties could come from R&D projects where field data are used as the basis of the work, and we could all benefit from better technology transfer of what we already know.

SUMMARY

Unconventional gas reservoirs contain large volumes of gas that can be produced economically at current gas prices — provided the best technology is used to find, drill, complete and fracture treat the reservoir. Hydraulic fracturing technology has developed substantially since the 1950s when it was first used widely in North America. We now have better fluids, propping agents, equipment and technology for collecting and analyzing data, and models for both designing and analyzing treatments. It has been very interesting over the past 30 years to be part of the technology development surrounding hydraulic fracturing. However, as discussed above, there is still a lot to do.

This article is based on a presentation at the DEA Workshop, 20-21 June 2006, Galveston, Texas.