AS SEEN IN E&P MAY 2013

A day in the life of a barrel of water

Energized solutions in hydraulic fracturing can help operators save water and see performance improvements.

Robin Watts, Linde North America

Hydraulic fracturing creates the largest demand for water of all drilling and completion activities. The US Environmental Protection Agency (EPA) estimated that between 2.5 MMgal and 5 MMgal of water are used per well to fracture a formation. That is a lot of water to acquire, transport, store, and manage.

Sending fluid downhole is not the only time that companies need to deal with water. Produced water tends to increase as the well ages. Reported water-to-oil ratios increase from 1:1 early in the life of a well to 15:1 later on. The EPA estimated that wastewater recovered from hydraulic fracturing varies from 10% to 70% depending on the geologic formation. The proper disposal of this water represents another significant investment for energy producers and service companies.

In addition, current water demands are not sustainable. A 2010 study for the Natural Resources Defense Council found that more than one-third of all counties in the contiguous US will face higher risks of water shortages by mid-century.

All of this forces energy producers and service companies to understand the total life-cycle costs of water. Exploring alternatives to water such as carbon dioxide or nitrogen to energize fracturing fluid solutions and reduce water volume also is in order.

Total life-cycle costs

Total life-cycle water costs include acquisition, transportation, storage, usage, treatment, recovery, recycling, reuse, and disposal.

The water source affects overall costs. Any expense to treat water, including building plants must be part of the water acquisition calculus. The same goes for water storage. Engineering and building impoundments, pipelines, and security fencing add to the cost of acquiring and storing water.

Transporting water to and from remote well sites also adds considerable cost. It takes approximately 500 truck trips to deliver 3 MMgal of water to a site, and it is estimated that between 65% and 90% of truck visits to the wellhead during drilling and completion are for water deliveries for hydraulic fracturing and flowback water removal. Even if pipelines are built to reduce truck traffic, the expense of building the pipeline is part of the total overall water cost.

Flowback and produced water are typically disposed of in one of three ways: in injection wells, at treatment facilities, or through recycling and reuse. Class II underground injection wells are the most common method. Recycling depends on many factors, and treatment facilities are helpful when nearby. No matter which disposal option is selected, removing water from the wellhead is a cost that must be considered.

Alternative fracturing fluids

Operators have alternatives that can reduce water volume and expense in hydraulic fracturing. The Energy Solutions group of Linde North America has a framework to calculate hydraulic fracturing fluid life-cycle costs and predict productivity via fracturing simulations.

When the total life-cycle cost of water approaches US \$5/bbl to \$10/bbl, Linde recommends using fluids energized with CO_2 and/or nitrogen (N_2) to reduce water consumption and unit production costs. Even at just \$5/bbl for total water costs, the economic benefits of energized solutions can be realized relatively quickly when well hydrocarbon productivity gains of 10% or greater are achieved.

CO_2 and N_2 are used to energize fracturing fluids to enhance performance and productivity with the added

Estimated Costs, Water vs. CO_2: Anadarko Basin

Fracturing Fluid Cost Comparison - Anadarko, 30-stage well

	Incremental Water	CO_2
Acquisition, management (post-frac) & Disposal Costs	\$ 282,088	\$1,346,255
DELTA cost of water to CO_2	**(\$1,064,166)**	
Cost/bbl equivalent	\$ 2.77	\$ 13.20

FIGURE 1. The barrel cost equivalent comparison and productivity payback improvement for water vs. CO_2 energized fluid is shown. (Images courtesy of Linde North America)

Productivity Gain Value

100	Boe/d
30%	incremental production
30	incremental production, Boe/d
\$100	\$/Boe price
\$3,000	incremental production, \$/d
\$1,095,000	incremental production, annual \$
\$1,064,166	incremental cost of CO_2 over water
.97	payback years

FIGURE 2. This figure delineates the simple estimated productivity value for a 30% incremental production gain.

benefit of reducing water volume for fracturing jobs. A 40-quality CO_2 foam can mean leak-off reduction that reduces total fluid-volume needs by 25%, while a 75-quality CO_2 foam can reduce total fluid-volume needs by up to 50%.

The initial cost of fluids energized with CO_2 or N_2 in certain circumstances may exceed initial water acquisition costs. But in a well-designed fracturing process CO_2 and N_2 can reduce other costs and improve well performance to yield a lower total operating cost or unit cost of production. The following examples, run through Linde's simulation framework, compare the total life-cycle costs of hydraulic fracturing using water-based or energized fluids. Situations where energized solutions increase productivity and thus offset lower per-barrel water costs are explored. The examples use a simplified method for quickly assessing the potential total costs of hydraulic fracturing fluid choices as well as implications for productivity to provide estimated unit costs of production. Certainly, capital investment can have a major impact on unit costs.

Capital costs

In an example from the Anadarko basin (Figure 1) the cost of incremental water acquisition and disposal appears on its face to be significantly lower than the 40-quality CO_2 energized fluid option (\$2.77/bbl for water vs. \$13.20/bbl for CO_2). However, to get per-barrel water costs so low, the operator made a \$10 million capital investment for an injection well to dispose of the water. While the cost of the CO_2 program approaches \$1.4 million, there are no post-fracturing management or disposal costs associated with CO_2.

The Anadarko region is undergoing drought conditions and projected water shortages, making alternatives to water important to sustainable well programs. In addition, CO_2-energized fluids may significantly reduce the payback period for incremental fracturing costs. In this particular case payback would be less than one year, assuming well productivity improvement of 30% (or less than half a year at 60%), which is achievable based on actual operator experience in the region (Figure 2).

Supply, management, and disposal complexities

In an example from the Uinta basin the complexities of supply, management, and disposal drove water's per-barrel cost to \$14.31 as compared to total CO_2 costs of \$14.91/bbl. Recycling, reuse, and disposal can be particularly expensive in this part of the Rockies. Water acquisition can explode from \$5/bbl to \$25/bbl if one accounts for recycled water. Disposal costs can rise to \$8/bbl, up from \$5/bbl. In this scenario total water costs rise to \$36.56/bbl as compared to the CO_2 treatment costs at \$14.91/bbl.

As in the Anadarko example, CO_2 performance can offset its costs and lower water production. One sampling of production results using various fracturing fluids in a three-county region in Utah found higher natural gas production from wells fractured with a higher quality CO_2 solution. Water production was greater in wells treated with higher water-content fluids. With no CO_2 or lower quality CO_2, water production was 4.5 times to 1.8 times greater than using higher quality CO_2. Gas production on average was 5% to 75% higher when using low-quality to higher quality CO_2 as compared to water.

High disposal costs

A Marcellus example shows the injection well disposal costs are at a premium, putting total water costs at \$15.87/bbl. CO_2 costs are \$12.55/bbl. If the water source changes to recycled water at a cost of \$13/bbl instead of \$3/bbl, the total water cost rises to \$25.87/bbl. This is substantially higher than a high-quality CO_2 foam fracturing fluid that also can deliver productivity enhancements.

Taking the full view

When producers and service companies take the full view of their water costs, they can more accurately determine total cost and make better, more informed decisions. Injecting less volume and fewer chemicals can significantly reduce associated costs and the environmental impact. When drought conditions send the water acquisition prices soaring or conditions affect disposal options, being able to calculate the cost of alternative fluids can mean the difference between an optimally productive, profitable well and a well that merely performs "well enough." E&P