Making our world more productive

A Day in the Life of a Barrel of Water.

Evaluating Total Life Cycle Costs of Hydraulic Fracturing Fluids.

Water Management Segments in the Development and Production of Shale Resources

Sourcing	Transport	Storage	Pumping (hydraulic fracturing)	Treatment / Flowback / Produced	Disposal
Surface water	Trucks	Frac tanks		Centralized treatment facility	Disposal wells
Ground water	Temporary surface lines	Storage ponds		Near-field treatment facilities	
Municipal wastewater	Pipeline	Gathering system		Mobile treatment units	
Industrial wastewater	Rail			No post-treatment	
Recycled water					

Figure 1. E&P companies must account for costs across the total life cycle of water.
Source: International Association for Energy Economics, IAEE Energy Forum, Q1 2012, "Water Management Economics in the Development and Production of Shale Resources," Christopher J. Robart, Pac-West Consulting Partners.

For several years now, regulatory agencies including the U.S. Environmental Protection Agency (EPA) and energy associations like the American Petroleum Institute (API) have provided recommendations, regulations and guidelines to improve water management in oil and gas exploration. Yet, to fully appreciate the life cycle costs of fluids – including water – used for hydraulic fracturing, one needs to examine the total costs of fluid acquisition, management and disposal. Typically, these costs are divided between various groups within an operator's organization (i.e., completions and production), with budgeting emphasis on acquisition costs during the completions process.

This paper examines the total life cycle costs of hydraulic fracturing fluids, comparing water-based and energized solutions. It evaluates when fracturing fluids energized with carbon dioxide (CO_2) can be used to reduce water volume for more economical hydraulic fracturing, though the same evaluations can be made for nitrogen (N_2) as well. It also evaluates how the selected fracturing fluid can affect productivity. In certain situations, the increased productivity achieved with energized solutions can more than offset lower per-barrel water costs, driving a lower overall unit cost of production. To approach our analysis, we will look at "A Day in the Life of a Barrel of Water" used for hydraulic fracturing.

The True Cost of Water

Hydraulic fracturing represents the largest demand for water in drilling and completions (orders of magnitude greater than drilling). The EPA estimates that 2.5 million to 5 million gallons of water are used per well in hydraulic fracturing. Chesapeake Energy, for example, reports it averages 4.5 million gallons of water per well to fracture its deep shale gas wells. In addition, produced water (post-flowback) tends to increase as the well ages, with reported water-to-oil ratios increasing from 1:1 early in the life of a well to 15:1 late in life. The EPA estimates that wastewater recovered from hydraulic fracturing varies from 10% to 70%, depending on the geologic formation.1 For a 5 million gallon hydraulic fracturing job, recovery rates could mean between 500,000 and 3.5 million gallons of fluid returned to the surface. The cost to acquire, transport, store, use, treat, recover, recycle and reuse, or dispose of water represents a significant investment for energy producers and service companies (Figure 1).

Evaluating the total life cycle of water used in well completions and production is paramount to understanding its true costs. When the total life cycle costs of water approach $5 to $10 per barrel, *"The cost to acquire, transport, store, use, treat, recover, recycle and reuse, or dispose of water represents a significant investment for energy producers and service companies."*

Linde recommends energized solutions featuring CO_2 and/or N_2 to reduce water consumption and unit production costs. Even at just $5 per barrel for total water costs, the economic benefits of using energized solutions instead can be realized relatively quickly, when well hydrocarbon productivity gains of 10% or greater are taken into account.

The EPA, in a draft study plan on hydraulic fracturing[2], took a full water life cycle approach to understanding water usage. This included water acquisition, chemical mixing and site management, well construction, injection/fracturing, flowback and produced water management, and wastewater treatment and disposal. Producers and service companies are wise to adopt this water life cycle evaluation to fully appreciate the cost of water as well as alternative methods to reduce those costs. According to Halliburton, $51 billion is spent annually on water management costs[3]. Factors driving up water costs, including supply constraints and increasing demand, are well recognized by the oil and gas industry. The driving factors for change include: the scale and demand of well programs in some unconventional plays; public perception; and municipal demands for water that are projected to continue to outpace supply. These put increasing and competing pressure on water sources, particularly in regions with ongoing drought conditions.

In addition, current water demands are not sustainable. A new study found that more than 1,100 U.S. counties – one-third of all counties in the lower 48 – will face higher risks of water shortages by mid-century. More than 400 of these counties will face extremely high risks of water shortages[4].

These same drivers are leading the oil and gas industry to minimize fresh water usage and maximize water reuse via produced water/flowback water pre-treatment. Even so, water rights add a layer of complexity to the true ownership of water being "produced" from a well.

Acquisition and Storage

The water volume required for hydraulic fracturing depends on the geology of the formation, the operating environment, fracture design and type of well that is being drilled, as well as the scale of the overall well development program. The source of water affects overall cost, whether from surface water, fresh or non-potable groundwater, municipal supplies, treated wastewater (municipal or industrial), power plant cooling water, and even recycled/treated produced or flowback water. According to information from API[5], Encana and Apache built a plant to treat water from an underground non-potable aquifer that has significantly reduced surface water use and is projected to meet 80% of water needs for hydraulic fracturing in the Horn River Basin of British Columbia. The cost of building the plant, however, must be part of the water acquisition calculus.

Likewise, when Chesapeake[6] built impoundments and pipelines to store surface water, it enabled them to reuse 100% of surface water in the Marcellus and reduce trucking to the well site. But there are costs associated with engineering and building the lined impoundments, pipelines and security fencing.

Non-potable Water Sources

Non-potable sources of water are increasingly desirable for reducing dependence on fresh water sources. Devon Energy[7] was reportedly the first oil sands operator to use 100% saline water for its steam-assisted gravity drainage operations, recycling more than 95% of the saline water for reuse in steaming operations. Seneca Resources[8] minimizes fresh water use by the permitted withdrawal of Acid Mine Drainage (AMD) in the Marcellus shale. This is a viable solution, yet questions remain, such as any long-term liability, results when AMD mixes with flowback, and whether AMD will yield the volumes needed for hydraulic fracturing. Also, non-potable water sources may require pre-treatment that adds cost. Non-potable may present a lower upfront cost than fresh water, but other costs need to be considered when choosing this option. Finally, consideration must be given to the possible negative impacts, if any, of water reuse, with and without pre-treatment, on the post-intervention production of wells.

Transportation Considerations

Transporting water to and from remote well sites adds considerable cost – and can increase risk, since many injuries and accidents associated with exploration and production occur on the roads leading to these remote locations. It takes approximately 500 trucks to deliver 3 million gallons of water to a site, so reducing truck trips is critical to lowering cost and risk, as well as reducing emissions. It is estimated that between 65% and 90% of truck visits to the wellhead during drilling and completions are due to hydraulic fracturing water delivery and flowback water removal. Anadarko Petroleum Corporation[9] implemented its Anadarko Completion Transport System of temporary pipelines to transfer recycled flowback fluids in the Uinta Basin, which resulted in an 85% reduction of water truck traffic and decreased fresh water consumption for well stimulations by 2.5 million barrels in 2010.

Disposal and Treatment

Flowback and produced water are typically disposed of in three ways: in injection wells, at treatment facilities, or through recycling and reuse. Class II Underground Injection Control wells are the most common disposal method, while treatment facilities are limited to geographies where they are located[10]. Temporary, centrally located treatment facilities have been used in active drilling areas. Recycling options depend on many factors, including the rate and volume of water needing treatment, its constituents and consistencies, discharge requirements and more. In the Barnett Shale, Devon's water recycling efforts can fracture more than 100 wells using recycled water. More recently, Linn Energy invested $36 million in North Texas for facilities including a pipeline and pit system to recycle water for a completions program associated with 2–3 rigs they operate in the region[11]. In addition, most operators do not consider the additional costs of water treatment when using gelled systems for hydraulic fracturing. The flowback water can have residual polymer and, therefore, higher viscosities that result in treatment problems downstream[12].

If, instead of disposing of flowback or produced water, this resource is reused, it may present microbial, salinity and hardness issues. This will require service companies to use higher loadings of biocides and polymers for friction reduction or to achieve the viscosities needed to transport proppant because those additives do not perform as well in those reused waters. This will ultimately add cost in order to pre-treat water to make it more polymer friendly.

Using Less Water: Alternative Fracturing Fluids

In addition to the progressive approaches to water management already undertaken by energy producers and service companies, alternate sources of fracturing fluids can reduce water use. While initial acquisition costs for energized solutions using CO_2 and/or N_2 may, in certain circumstances, exceed initial water acquisition costs, in well-designed fracturing processes they can reduce other costs – such as clean up and disposal – and improve well performance to yield a lower total operating cost or unit costs of production.

There are a few means by which energized solutions can lower total water usage and its associated costs. The first is through the sheer displacement of water by CO_2 and/or N_2. If using a 75-quality foam, then the hydraulic fracturing fluid contains only ~25% water. The second is through reduction of the total volume of fluid needed to perform the hydraulic fracturing job. The greater the volume of energized component in the fluid, especially when it is foamed, the lower the leak-off of both the liquid and gaseous components of that fluid. This leak-off reduction can be quite significant:

→ 40-quality foam can mean leak-off reduction that reduces total fluid-volume needs by 25%
→ 75-quality foam can mean a leak-off reduction that reduces total fluid-volume needs by up to 50%[13]

A third consideration for reduction of total fluid volume is the significant expansion of cold CO_2 as the reservoir heats up the fluid. For a given volume of fluid pumped, the fracture volume is larger for CO_2 than for water.

These reductions in total fluid-volume needs can be achieved when the focus of the hydraulic fracturing job is to keep the same effective fracture half-length. When adjusting the fracture half-length for the improved proppant pack conductivity over water-based fracture treatments, this volume may be reduced even further.

Proppant Efficacy: Alternative Fracturing Fluids

Beyond total volume-fluid reduction, another significant benefit to using energized solutions comes from proper proppant placement and minimization of proppant embedment. High-pressure slick-water fracturing treatments can result in an effective loss of proppant due to embedment. Embedment factors utilized in fracturing design can account for an additional width loss equal to 2 grains of sand. For a 3-grain effective width design, 5 grains of sand must be utilized to account for a 2-grain width loss. Energized solutions for hydraulic fracturing do not have that same detrimental proppant embedment factor. From the example, if 5 grains must be in the design to achieve a 3-grain width, that is a factor of 67% more proppant for a non-energized fluid – adding to the cost compared to energized solutions.

Economic Benefits of Energized Solutions

To examine the economic benefits of a stimulation program, unit cost-per-production calculations can help determine those situations when a lower, equal or higher initial investment in energized solutions delivers a lower overall unit cost of production. When measuring well productivity over time – expected ultimate recovery – as a decline curve, the net present value of that production can be improved by minimizing the slope of that curve. More than effective fracturing, the benefits of energized fluids are related to the flowback and production performance. Their enhanced clean-up significantly improves flowback and initial production most significantly in dry and depleted formations.

Linde has a framework for looking at hydraulic fracturing fluid life cycle cost calculations (Figures 2 and 3) and predictions of productivity via hydraulic fracturing simulations that help customers anticipate total water costs and compare overall investment with energized solutions. Linde's cost calculation approach focuses on the hydraulic fracturing fluid acquisition, management and disposal. This includes any water returned to the surface during flowback and production. Costs for CO_2 will vary, depending upon distance from the source. All costs for booster pump, portable storage and operator(s) are included in the examples. The University of Texas at Austin's eFrac simulation program is designed for energized fluids. It accounts for the compositional and phase behavior changes of any compressible

Total Life Cycle Cost of Hydraulic Fracturing Fluids: Simple Calculator Tool

Water-based fluid		Total barrels
# of stages		
barrels/stage		
Incremental water		bbl
Acquisition		method (source, recycle, reclaim...)
		$/bbl water
		$/ton CO_2
Management		
		months, flowback
		% flowback (over same months)
		days/month
		# storage tanks
		$/day/storage tank
		hrs setup/tank
		hrs monthly maintenance/tank
		$/hr labor for maintenance & setup
Disposal		
		method (source, recycle, reclaim...)
		$/bbl

CO_2 Foam Quality		
	0	# of stages
		foam volume improvement factor*
		barrels of foam
		barrels of water for foam
	5.41	CO_2 bbls/ton
		CO_2 tons

Input Calculated, can change value manually

Feed, can change value manually

*Use "Quality vs. Leak-off Values" for estimates. Barrels of foam estimated adjustment based upon leak-off, fluid clean up, embedment...(if targeting equal fracture volume).

Figure 2. The input sheet for simple fracturing fluid calculator.

Total Life Cycle Cost of Hydraulic Fracturing Fluids: Simple Calculator Tool

Fracturing Fluid Cost Comparison

				Incremental Water	CO_2
	Unit	# Units	Unit Costs	Total costs	Total costs
Acquisition					
Water - Purchase	bbl	-	$	$	
CO_2 - Purchase	ton	-	$		$
Management (post-frac) Storage at Wellhead					
Incremental tanks (24)	mths	-	$	$	NA
Set-up / tank	hrs	-	$	$	NA
Labor monthly	hrs	-	$	$	NA
Disposal					
Injection Wells	bbl	-	$	$	
Total				$	$
Delta cost of water to CO2				$	
Cost/bbl equivalent				**Water**	**CO_2**
Acquisition, Management & Disposal				$	$

Figure 3. The output sheet for the simple fracturing fluid calculator.

"While initial CO_2 or N_2 acquisition costs may exceed water costs, in well-designed fracturing processes energized solutions can reduce other costs and improve well performance to yield a lower total operating cost or unit cost of production."

Estimated Costs, Water vs. CO_2: Anadarko Basin

Fracturing Fluid Cost Comparison – Anardarko, 30 stage well

	Incremental Water	CO_2
Acquisition, Management (post-frac) & Disposal Costs	\$ 282,088.00	\$1,346,255.00
DELTA cost of water to CO_2	(\$1,064,166.00)	
Cost/bbl Equivalent	\$ 2.77	\$ 13.20

Figure 4. Barrel cost equivalent comparison and productivity payback improvement for water versus CO_2 energized fluid.

Productivity Gain Value

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

Figure 5. Simple estimated productivity value for a 30% incremental production gain.

component in a hydraulic fracturing fluid. These changes are not fully accounted for in any simulator currently available in the market place. The University's simulation program is designed specifically for looking at well stimulation productivity predictions utilizing energized hydraulic fracturing fluids.

A look at several examples in three shale plays helps discern the true costs of water and when energized solutions make the better investment. In addition, Linde has designed an economically viable flowback clean-up unit to remove CO_2 from flowback, allowing operators to profitably sell early gas production.

These examples compare incremental water costs on a per-barrel basis, evaluating a water-based fracturing fluid and an energized fracturing fluid. Incremental water cost is defined as the difference between water expenses for a water-only solution and an energized solution. To simplify the examples, we include the basic cost of acquiring, managing and disposing of the fracturing fluid in our calculations. For water management and disposal, we only account for some of the water returning that was initially used for fracturing (not any true produced water from the formation).

Typically, without major capital investment, the acquisition costs for water rise when the source comes from recycled or reused water (and/or mixtures thereof), depending on the complexities and source of acquisition. For fluid management, the cost rises based upon the amount of water returned out of the well and the length of time it takes for that return. This management cost increase may be attributed to the number of fracturing tanks required and their associated costs. Another cost not typically accounted for – and not included in these examples – is lift size. If water used for fracturing represents a significant volume of fluid increase during initial production, it may require a lift sizing larger than otherwise needed.

Other Hidden Costs

Some of the significant hidden costs not considered in these following examples (but associated with fluid acquisition, management and disposal) include environmental footprint and safety. Reduced water usage that leads to significant reductions in truck traffic also lowers emissions. Fracturing jobs that use pure N_2 without proppant eliminate truck deliveries of water and proppant for a substantial reduction in emissions. Water reuse, without proper treatment, can significantly increase microbial and scale-forming materials back into the well, as well as limit friction reduction and/or the desired friction-reducing properties. These materials impact everything from maintaining target fracturing pressures to well productivity.

With respect to safety, traveling to and from the wellhead has been identified as the highest risk for accidents associated with well site operations. Reducing the volume of fluid and proppant needed for fracturing reduces the number of trips to and from the site, thus lowering the risk for accidents.

Comparing the Cost of Water and CO_2

Example 1: When you own your own injection well, unit cost of production makes a difference!

A Day in the Life of a Barrel of Water in the Anadarko Basin

On its face, the low cost of incremental water acquisition and disposal in this Anadarko Basin example (Figure 4) indicates a significantly reduced cost per barrel than the 40-quality CO_2 energized fluid option. Total water cost is \$2.77 per barrel, compared with \$13.20 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 a CO_2 program approaches \$1.4 million, there are no post-fracturing management or disposal costs associated with the CO_2.

Other significant considerations affecting water use in the Anadarko region are current drought conditions and projected water shortages from competing demands. This means alternatives to water or more dramatic reductions in total water consumption may be required in order to sustain a well program in some regions.

Finally, CO_2 energized fluid treatment may significantly reduce the payback period for incremental fracturing costs. In this case, payback would be less than a year, assuming well productivity improvement of 30% (or less than a half a year at 60%), which is achievable (Figure 5).

Simulated Productivity Comparison of Fracturing Fluid Alternatives: Anadarko's Cleveland Formation

Fracture Performance

Fluid Type	Water (eq vol)	CO_2 Foam Quality 40 (eq vol)	40 (75% vol)
L_f (ft)	790	1410	1160
$W_{average}$ (in)	0.1482	0.261	0.2445
k_f (mD)	5000	5000	5000
L_f/L_{re}	0.88	1.32	1.25
F_{cd}	2.63	1.05	1.25
k_d/k	0.1	0.12	0.15
J/J_0	4.5	7.44	7.46
% change over water		65.3%	65.8%

L_f (ft)	fracture ½ length
$W_{average}$ (in)	fracture width, average
k_f (mD)	fracture permeability (INPUT value)
L_f/L_{re}	unitless effective draining radius
F_{cd}	dimensionless fracture conductivity
k_d/k	damaged zone perm/reservoir perm
J/J_0	unitless productivity index

Figure 6. Simulated fracturing fluid performance in the Anadarko's Cleveland Formation using the University of Texas eFrac simulator. Comparison of unitless productivity J/J_0.

Estimated Costs, Water vs. CO_2: Uinta

Fracturing Fluid Cost Comparison – Uinta, 8 stage well

	Incremental Water	CO_2
Acquisition, Management (post-frac) & Disposal Costs	$540,217	$562,565
DELTA cost of water to CO_2	($22,348)	
Cost/bbl Equivalent	$14.31	$14.91
Acquisition, Management (post-frac) & Disposal Costs	$1,379,913	$562,565
DELTA cost of water to CO_2	$817,348	
Cost/bbl Equivalent	$36.56	$14.91

Figure 7. When water complexities start to put solutions costs at par with CO_2-based solutions, water quickly escalates to being more costly when recycling is the source.

According to operators in the region who are experienced in working with CO_2, N_2 and water-based fracturing fluids, reported productivity improvements in the Anadarko region are as high as 20% to 30% for CO_2 foams. These reported improvements were also compared in simulations of the Anadarko's Cleveland formation, indicating a significant improvement using a 40-quality CO_2 foam over a water-based, non-energized fluid. The simulated unitless productivity (Figure 6) indicates a >60% improvement in a CO_2 energized fluid over a water-based fluid.

Example 2: When water usage and disposal is difficult and costly, equivalent costs quickly rise and water becomes the more expensive option.

A Day in the Life of a Barrel of Water in the Uinta

When water costs increase due to complexities of supply, management and disposal, they can be comparable to or exceed the cost of CO_2 solutions. In this Uinta example (Figure 7), total CO_2 cost was $14.91 per barrel, compared to water's $14.31 per barrel.

Recycling, reuse and disposal can be particularly expensive in this part of the Rockies. The water acquisition costs could easily explode from $5 per barrel to $25 per barrel if one accounts for recycled water. Disposal costs can rise as high as $8 per barrel, up from $5. In this scenario, total water costs rise to $36.56 per barrel compared to the CO_2 treatment costs at the $14.91 per barrel level.

Production Rate vs. Quality

Gas Wells-CO_2 vs. Other Fracturing Fluids

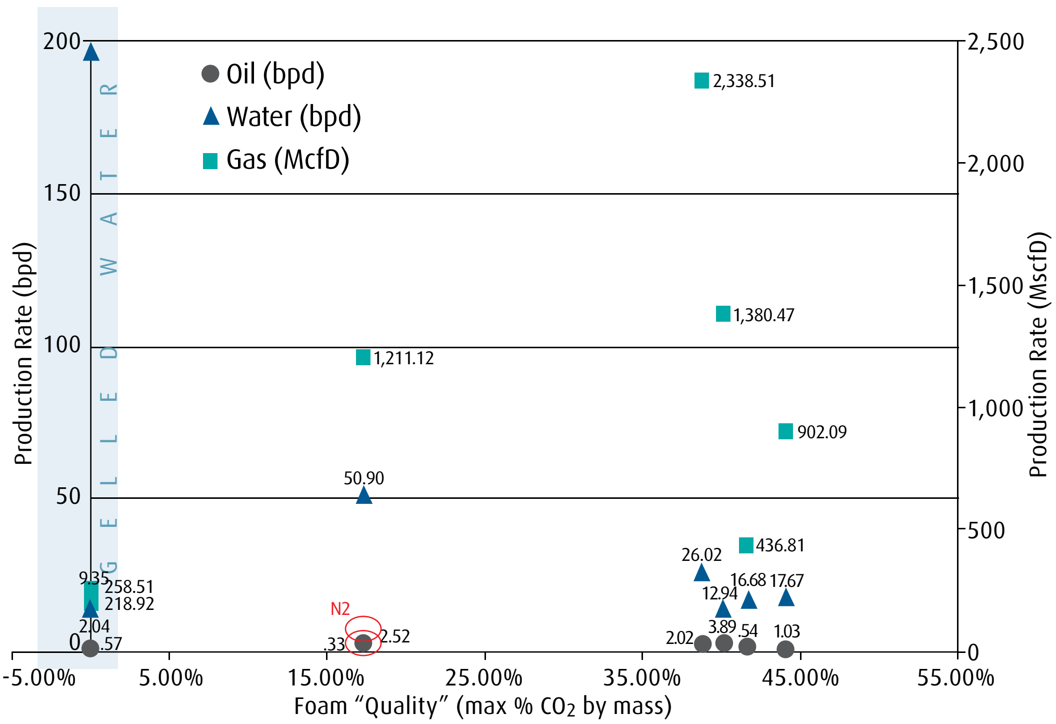

Figure 8. Average daily production rates of gas, oil, and water for 11 wells during ~7 months of production. Using CO_2 reduces water production and increases gas production. *Source: Production data from http://oilgas.ogm.utah.gov/index.htm; Completions data from FracFocus.org.*

As in the Anadarko example, productivity can be increased with the use of energized fracturing solutions. A review of well productivity in the Uinta where various fluids are used indicates superior performance in wells fractured with a CO_2-based solution. The results also indicated lower water production.

Figure 8 demonstrates a sampling of production results utilizing various fracturing fluids in a three-county region of Utah. For gas wells, the results, on average, indicate a higher natural gas production for wells fractured with a higher-quality CO_2 solution. They also show greater water production for wells treated with higher water-content fluids.

The graph supports a regional operator's conclusion that using lower quality CO_2 yields less hydrocarbon production and more water production. With no CO_2 or lower quality CO_2, water production was 4.5 to 1.8 times greater than using higher quality CO_2. Gas production was, on average, 5% to 75% higher when using low to higher quality CO_2, compared to water.

Example 3: When the cost of disposal is high, CO_2 fracturing fluids are clearly the more cost-effective choice. Productivity gains are a bonus.

A Day in the Life of a Barrel of Water in the Marcellus

This example also demonstrates how high disposal costs lead to water being the more expensive fracturing fluid option (Figure 9). In this 22-stage well Marcellus project, injection well disposal costs are at a premium, putting total water costs at \$15.87 per barrel, while CO_2 cost is \$12.55 per barrel. If the water source changes to recycled water, at a cost of \$13/barrel – up from \$3 per barrel – the total cost of water rises to \$25.87 per barrel. This is substantially higher than a high quality CO_2 foam fracturing fluid.

In addition, the productivity gains noted in previous examples are achievable here too, making energized solutions a clear choice.

The examples above 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.

Estimated Costs, Water vs. CO_2: Marcellus

Estimated Costs, Water vs. CO_2
Fracturing Fluid Cost Comparison – Marcellus, 22 stage well

	Incremental Water	CO_2
Acquisition, Management (post-frac) & Disposal Costs	$2,924,212	$2,311,713
DELTA cost of water to CO_2	$612,498	
Cost/bbl Equivalent	$ 15.87	$12.55
Acquisition, Management (post-frac) & Disposal Costs	$4,766,887	$2,311,713
DELTA cost of water to CO_2	$2,455,174	
Cost/bbl Equivalent	$ 25.87	$12.55

Figure 9. When disposal costs are high, water can be the most expensive fracturing fluid option.

Taking the Full View

When producers and service companies take the full view of their water costs, factoring in expenses during both completion and production, and evaluate potential productivity gains, they can more accurately determine total cost and make better, more informed decisions. Certainly, injecting less volume and a fewer number of chemicals can significantly reduce associated costs and environmental footprint. 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 a most productive, profitable well or a well that merely performs "good enough". Linde's efforts to better calculate total costs and simulate the effects of energized solutions on performance will help customers better evaluate the resources available and choose the best fracturing fluid for the job.

Footnotes

- 1: US EPA, **Study of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources: Progress Report**, December 2012
- 2: **EPA Hydraulic Fracturing Study Plan,** EPA/600/R-11/122, November 2011.
- 3: Halliburton, **Shale Water Management Initiative 2012** presentation, November 29, 2012.
- 4: National Resources Defense Council, **Water Supply Sustainability Index (2050) with Climate Change Impact**, www.nrdc.org/globalwarming/watersustainability/index.asp
- 5, 6, 8, 9: American Petroleum Institute, **Guidance/Best Practices on Hydraulic Fracturing**, HF2 – Water Management Associated with Hydraulic Fracturing, 1st Edition, June 2010.
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- 13: Ribeiro, L.H. and Sharma, M.M. 2011. **Multi-Phase Fluid-Loss Properties and Return Permeability of Energized Fracturing Fluids.** Paper SPE 139622 presented at the SPE Hydraulic Fracturing Technology Conference and Exhibition, The Woodlands, TX, 24-26 January.

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With its innovative solutions, Linde is playing a pioneering role in the global market. As a technology leader, it is our task to constantly raise the bar. Driven by our tradition of entrepreneurship, we are working steadily on developing new high-quality products and innovative processes.

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