PIPELINE NEWS North
Northern British Columbia and Alberta's Oil and Gas Industry

Published August 10, 2012
INDUSTRY NEWS

Every Drop Counts

Industry study explores the limits of reusing water for fracking James Waterman

There are a lot of reasons why the oil and gas industry would want to reduce the use of freshwater resources in its hydraulic fracturing operations.

Just ask Keith Minnich.

The water sustainability advisor with Talisman Energy has been concerned with water management issues for almost thirty years, ever since he first involved himself with the idea of recycling and reusing produced water from oil wells in 1985.

“I worked on projects in the Middle East and then heavy oil in Alberta,” said the engineer. “And got involved in the gas industry in 2010.”

Most recently, he has been the coordinator of an initiative known as the Fracturing Fluid Flowback Reuse Project, the results of which have recently been through the peer review process and should soon be publicly accessible on the Petroleum Technology Alliance Canada (PTAC) website.

M-I SWACO and Schlumberger, which work on drilling optimization, completed the project work, which was funded by the industry-sponsored Science and Community Environmental Knowledge Fund (SCEK) and Alberta Upstream Petroleum Research Fund (AUPRF).

“M-I SWACO brought the water treatment expertise and Schlumberger brought the hydraulic fracturing expertise,” said Minnich.

It all began with various concerns around reducing waste.

“There’s a general recognition that, if water can be reused, that reduces the demand for freshwater and reduces disposal costs,” explained Minnich.

Produced water is commonly injected into wells deep underground, but those disposal sites are rarely close to natural gas drilling pads in western Canada.

“The trucking cost is significant,” said Minnich.

“Now that doesn’t apply in every location,” he admitted. “For example, Texas has lots of deep wells and they’re inexpensive. Disposal costs aren’t the driver. In Texas, it would be more freshwater reduction.

“In other parts of North America – and Canada in particular – there’s freshwater available, but disposal’s not. The driver becomes eliminating or reducing disposal costs and all the truck traffic associated with that disposal.”

Although it may not seem to be a significant environmental issue along the lines of freshwater consumption, landowners living near oil and gas industry operations, according to Minnich, most commonly raise concerns about truck traffic.

“And I think that’s a very local concern [and] the water consumption is more of a regional concern,” he said.

“I’m not sure to what extent the public at this point really understands the whole concept of the reuse,” Minnich added.

“But anything that reduces truck traffic is viewed quite favourably. That’s the feedback that we have. And if it’s putting in a pipeline, if it’s eliminating disposal – I don’t think they necessarily care how we do it just as long as it’s done.”

Reusing flowback water isn’t exactly a new idea, but determining the quality of recycled water suitable for hydraulic fracturing was a subject that was addressed thoroughly for the first time with this study.

“That’s one of the main reasons this project was initiated,” said Minnich.

“The generally accepted belief several years ago was that water for hydraulic fracturing had to be close to freshwater quality,” he continued.

“Over the past several years, the companies have done some experimentation with minimizing treatment and had good results. And the service providers and additive suppliers have developed additives that are tolerant to high salinity.”

Additives known as friction reducers were particularly affected by salinity prior to those advances.

Friction reducers are necessary for pumping water into the well at a velocity that creates adequate pressure to fracture the rock that holds the natural gas. Without friction reducers, it is very difficult to fracture that rock and produce any gas.

“Their performance was inhibited by salinity,” Minnich said of the old additives. “That was one of the big breakthroughs, that saline tolerant friction reducers were developed.”

The result of those early experiments with water treatment and technological advances such as saline tolerant additives was that the industry began to seriously ask questions about the water quality necessary for hydraulic fracturing.

“And what we found was there was no consistent answer to that question,” said Minnich.

“And it has a lot to do with how quickly the technology is developing. So, what we wanted to do was to provide a framework for answering the question: what water quality do I need? And once that was determined, then the companies can select the water treatment that’s appropriate.

“In the past,” he continued, “things were addressed the other way around. It was water treatment providers saying, ‘Here’s what we can do.’ And [saying], ‘We can remove all the suspended solids. We can remove all the colour. We can remove all the dissolved solids.’

“But it occurred to us that that was actually looking at the problem from a different perspective than what would minimize the treatment. So, instead of going at it [from the perspective of] what can we do or what can be done, we said, ‘What do we need?’ And so that framework is intended to provide a method to answer that question: What do we need as water quality?”

That quality can vary from well to well because the injected water has to be compatible with the particular formation. One of the related issues is the potential for the water to react with the formation to cause scaling in the well.

“Then another is the compatibility of the fracture fluid with the additives,” said Minnich. “We might find that we can inject water of a certain quality and it doesn’t react poorly with a formation, but that water quality might not be sufficient for the additives to perform.”

There have been advances in terms of the scaling problem.

“Traditionally, it’s been considered risky to inject water with high levels of hardness, and the immediate reaction several years ago was that the hardness should be removed,” Minnich explained.

“There’s anecdotal evidence of high-hardness waters used successfully,” he continued.

Hard water contributes to the creation of scale compounds such as calcite and barite.

“Calcium will react with carbonate and form calcite,” said Minnich. “That’s the same material that you’ll see in the bottom of a tea kettle or in a water heater. Barite is barium and sulfate. And the flowback water typically has high barium concentrations.

“But one thing we observed is there’s very little sulfate in these waters. That’s one of the things that came out of the study that suggested it’s not necessary to remove barium in all cases. If there’s not sulfate, barium sulfate precipitation isn’t an issue.”

Calcite and barite commonly form where there is a loss of pressure in the well.

“And, in extreme cases, those scales can reduce the flow of hydrocarbon out of the well,” added Minnich.

An important aim of the study was providing producers with a way to determine a level of acceptable hardness of the injected water so as not to cause scaling, as well as ensure that the water quality would allow the additives to perform properly.

That information is offered in “sensitivity tables” that Minnich calls “a significant step forward” for the industry.

“The sensitivity tables indicate what parameters in the hydraulic fracture fluid will have an impact on the performance of different additives and give suggested acceptable ranges,” he explained.

“Salinity is one. Another is hardness. Iron is another, because iron can interfere depending on the fracture fluid. That was another set of questions that people had in the past and the intent here is to provide some answers to that.”

Minnich is hopeful that the project will encourage reuse of flowback water across the industry as well as improve the work of water treatment providers.

“One of the challenges that they face is that they can describe what their technology can do to the water and, as I said, that’s a solution looking for a problem,” he said. “So, if this study better communicates to water treatment suppliers what are the important parameters for fracture fluid, they can tune their offerings to the market in a better way.”

Despite that progress, this project is probably still a work in progress.

“Because the technology changes,” said Minnich, “this work will hopefully be obsolete in a year or so.”

Story URL: http://www.pipelinenewsnorth.ca/article/20120810/PIPELINE0118/308079954/-1/pipeline/every-drop-counts