

Technique Increases Jonah Production

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DENVER—The unconventional natural gas business is characterized by tight margins in almost every case these days. Operators are challenged to minimize costs and maximize well productivity. While cost control is practiced routinely, most profitability gains are achieved through breakthroughs in production volume and efficiency.

Accordingly, achieving a 23 percent production improvement in a marginal environment with reduced materials and without the occurrence of near-well bore screen-outs as a result of implementing a new channel fracturing technique in the giant Jonah Field was hailed as a paradigm shift by the operator, Encana Oil & Gas (USA) Inc.

The Jonah Field is a classic tight gas environment with permeabilities in the micro-Darcy range, situated near Pinedale, Wyoming. Encana specifically selected the Stud Horse Butte area of the Lance formation for testing channel fracturing technology because the area typified the challenges the company faced in its unconventional natural gas development activities. A field experiment was issued using the new hydraulic fracturing technique, which is purpose-engineered to improve gas production by establishing highly-conductive pathways through the dense rock.

The Lance formation ranges from 2,000 to 3,000 feet in thickness and is a series

of fluvial sand bodies that vary from 6 to 9 percent porosity and 0.0005-0.01 mD permeability. Net pay averages about 800 feet and gas saturation varies between 35 and 55 percent. According to the Wyoming Oil & Gas Commission, more than 1,600 wells have been drilled in the Jonah Field.

Historically, the Stud Horse Butte area presented many problems. For years, operators have tried stimulating the reservoir using gelled fluids as the carrying agent and sand as the proppant agent with limited success. The treatments actually impaired fluid recovery and subsequent productivity

from the formation. Wells in the Stud Horse Butte area typically were drilled to 13,000 feet total depth. They were completed using 12-15 fracture stages, each covering from 150- to 250-foot intervals and separated by flow-through bridge plugs for isolation and diversion. Stages consisted of 80,000 to 500,000 pounds of frac sand pumped in concentrations of one to six pounds per gallon of fluid.

Other techniques were tried with limited success. Slick water treatments resulted in moderate gains in productivity in some areas and poorer productivity in others.

FIGURE 1
Conventional (Left) versus Channel Fracturing (Right)

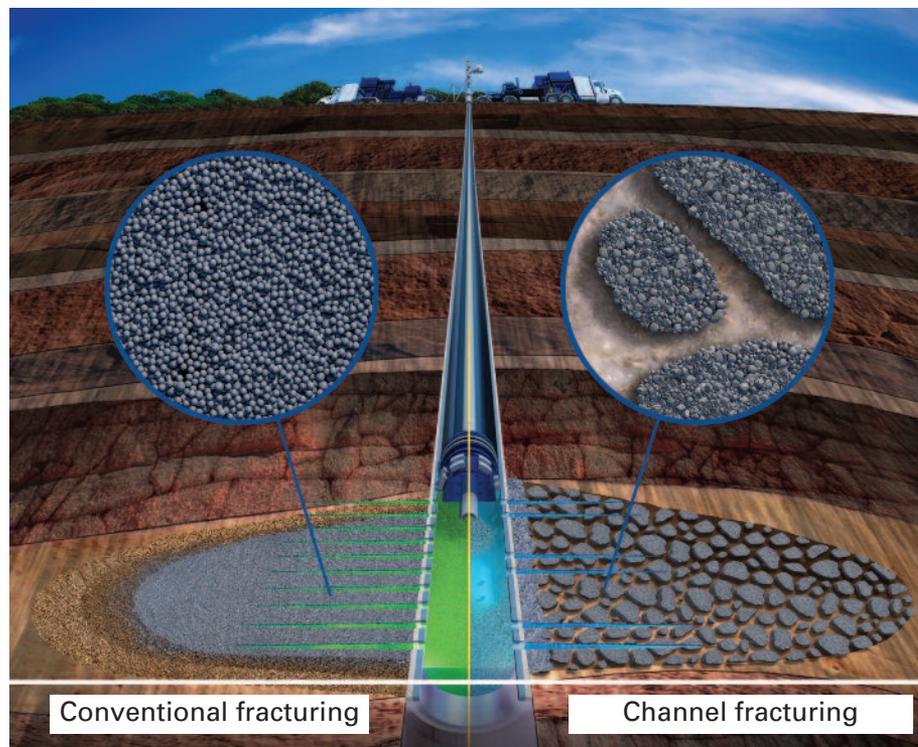
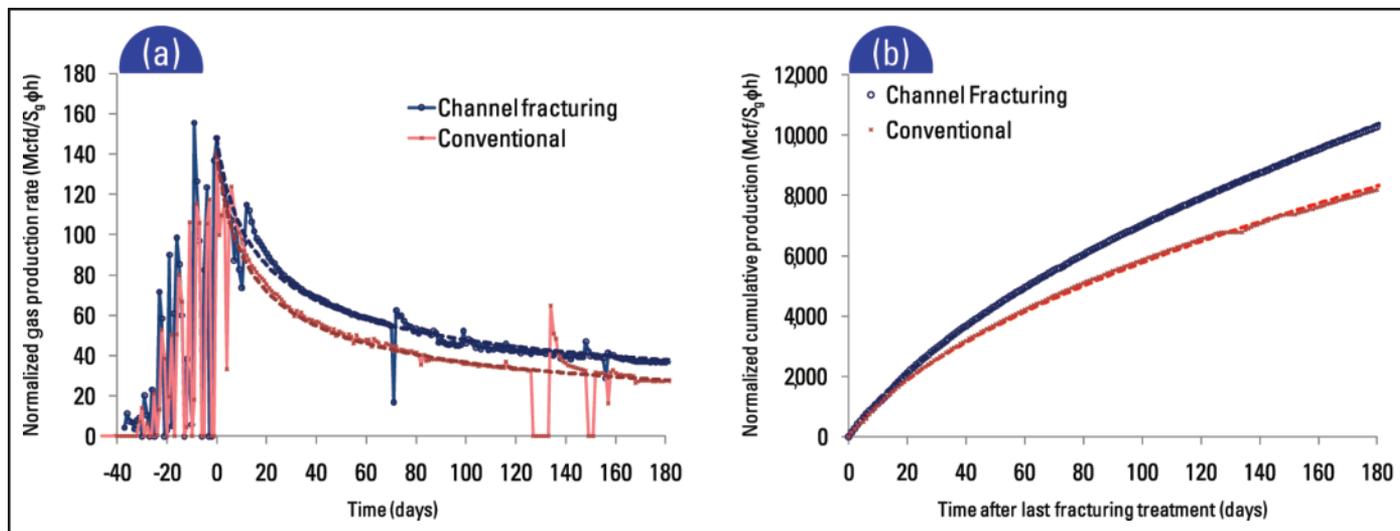




FIGURE 2

Gas Production for First Two Treated Wells
(Channel Fracturing = Blue; Conventional Fracturing = Red)



At times, using slick water rendered some improvement in fluid recovery, but fracture lengths were shorter and many treatments suffered from near-well-bore screen-outs. Switching to high-strength ceramic proppant did not provide substantial improvements in production, and this practice ultimately was abandoned because of the higher costs associated with the premium proppant.

Highly-Conductive Channels

Consequently, Encana decided to test the HiWAY™ hydraulic fracturing technique at the Stud Horse Butte area. The completion is prepared by implementing a limited-entry perforating scheme to help distribute the proppant for maximum reservoir contact. As shown in Figure 1, compared with a conventional hydraulic fracturing treatment (left), channel fracturing (right) results in a network of highly conductive channels in the proppant pack to increase production.

Specifically, the technique is applied by intermittent pumping of proppant-laden and proppant-free gelled fluid at high frequency to generate the network of conductive channels. The frequency of pulsations is enabled by specialized surface blending units. The proppant-laden pulses are held cohesive by a degradable fibrous material that dissolves after placement.

The result is a proppant pack infused with high-conductivity channels, yet one that retains its ability to prop open the fracture as it attempts to close after pumping is completed and fracture pressure is

bled off. The channeled proppant pack retains its integrity during post-frac flow back and cleanup.

Candidate wells for channel fracturing are selected using a geomechanical design program that calculates whether a condition of open channels will be attained for specific formation and pumping parameters. In addition to aiding in candidate selection, the program also helps the design engineer select specific parameters of the pumping schedule, such as the rates, pulse duration and frequency most suitable for the formation to be treated.

Initially, a single well in the Stud Horse Butte area had been treated following the channel fracturing method. Results of this trial well were very encouraging and convinced Encana to proceed with the more extensive testing in a selected portion of the Stud Horse Butte area. Five wells were chosen to be treated using the channel fracturing technique, with the remaining eight offset wells to be treated using field-typical procedures.

After completing the treatments, results from the five channel fracture-treated wells would be compared with those from the offset wells that were treated conventionally. Treatments for the test wells consisted of 58 stages, compared with 95 stages in the conventionally treated wells.

Test Parameters

To ensure that all treatments followed the same regime, test parameters were decided on and then fixed. All stages

used gel treatments of buffered borate fluids with 20/40-mesh sand at a maximum concentration of six pounds/gallon as the proppant agent. In the eight base case wells, 66 stages were treated using gelled fluids and 29 stages were treated using slick-water fluids. To ensure consistent reservoir parameters, all wells in the test were completed in 2010.

Furthermore, gas production data in the Jonah Field are normalized with respect to a standard reservoir quality factor ($s_g\phi h$, where $s_g\phi$ is the gas-filled porosity and h is the net pay height) to account for reservoir heterogeneity and the complexity that characterizes the Lance formation. This practice was adhered to in order to ensure proper comparisons. Care was taken to limit the variables among wells and stages so that reasonable conclusions could be drawn.

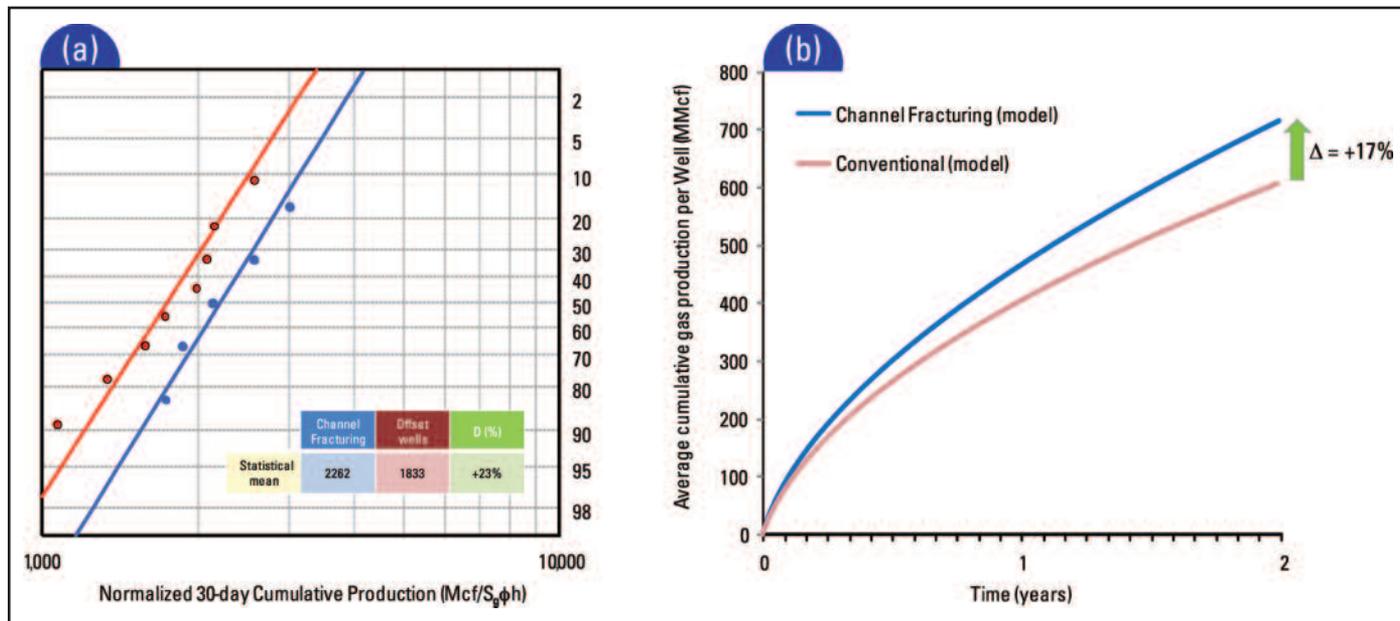
The first treated well employed the channel fracturing technique in 12 stages to stimulate 625 feet of net pay. The well had a reservoir quality factor of 36.86. Immediately following, a nearby offset well with 669 feet of net pay was treated in 12 stages using a conventional treatment technique. This second well had a reservoir quality factor of 37.5. The first well averaged 86,932 pounds of proppant and 2,152 barrels of fluid per stage, while the base case well used 156,058 pounds of proppant and 2,661 barrels of fluid on each of the 12 stages.

Comparing the initial pair of wells clearly shows that the channel fracturing



FIGURE 3

30-Day Cumulative Production for All Treated Wells
(Channel Fracturing = Blue; Conventional Fracturing = Red)



technique produced more gas. Figure 2 shows the 180-day cumulative gas production rates for the first two treated wells, with the channel fractured well shown on the blue curve and the conventionally treated well on the red curve. These encouraging early results provided sufficient incentive for Encana to complete the test on the remaining 11 wells.

Increased Production

To establish a broader statistical basis

for this field study, the remaining wells were treated following the same basic procedures. The average reservoir quality factor for all five wells treated using the channel fracturing technique was 39.12 and the average of the eight wells treated conventionally was 43.66. Each well's production was monitored closely for 30 days following treatment, and cumulative production results were obtained. Even though short-term results were scattered, the wells treated with the channel frac-

turing technique clearly outperformed the base case wells.

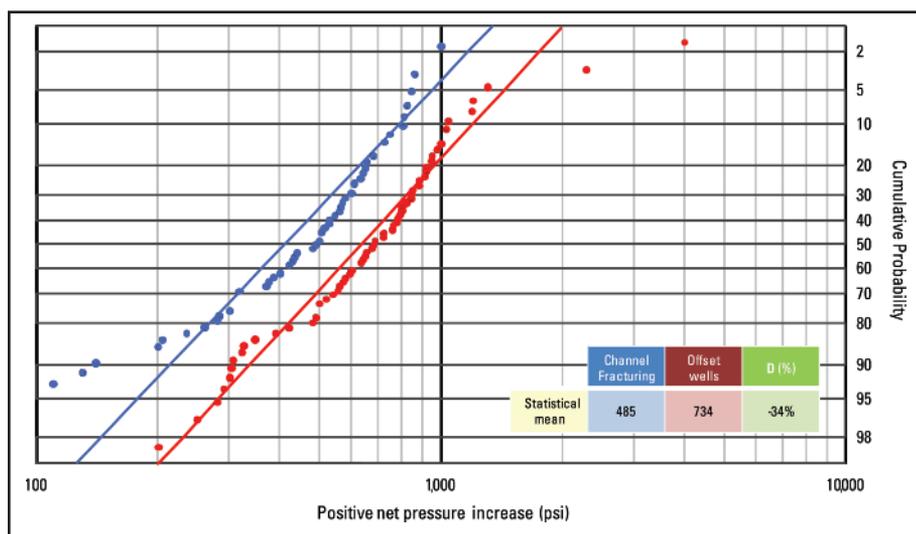
The widely scattered results were attributed to heterogeneities among the irregularly-distributed lenticular sand bodies penetrated by the wells. The left-hand panel of Figure 3 shows the normalized 30-day production of all 13 treated wells using the reservoir quality factor. These data trends were confirmed by extending the test production evaluation to one year. When the test data were projected over two years (right-hand panel in Figure 3), a 17 percent overall production increase equating to 100 million cubic feet per well in additional cumulative production over conventionally treated wells (red curve) was predicted for the channel fracture-treated wells (blue curve), based on fitting the Arp's model to the available data set.

Net pressure increase differences and near-well-bore screen-out rates between the two sets of wells were evaluated. Comparing pre- and post-frac shut-in pressure measurements, the base case wells averaged a difference of 734 psi per stage, while the wells treated using channel fracturing averaged a difference of 485 psi, as plotted in Figure 4 (channel fracturing is shown in blue dots).

The considerable reduction in net pressure gain is characteristic of systems with increased geometric length and reduced

FIGURE 4

Net Pressure Increase Comparison





fracture height. This results in localized fracture extension within the pay zone and typically allows more aggressive proppant ramping during the treatment for more effective proppant placement and fracture propagation length.

As for near-well bore screen-outs, outstanding results were obtained. On a per-stage basis, the channel fracturing technique experienced no screen-outs in 58 stages, whereas conventionally treated

wells experienced six screen-outs out of 95 stages treated. On a well-by-well basis, 37 percent of the conventionally treated wells had screen-outs compared to zero screen-outs on wells treated with channel fracturing.

A comparison of channel-fractured versus conventionally fractured results for the 153 frac stages studied in the 13-well campaign indicates that channel fracturing resulted in a 23 percent increase

in normalized initial gas production, a 17 percent increase in estimated two-year recovery per well, a 34 percent reduction in fracture net pressure increase, and no near-well-bore screen-outs.

By virtue of these results, the channel fracturing technique has been adopted as a customary practice for completing wells in the Jonah Field. More than 600 stages have been pumped in the field using channel fracturing technology. □

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