Channel Fracturing Enhanced by Unconventional Proppant Increases Effectiveness of Hydraulic Fracturing in Devonian Formations of Russia’s Oilfields

Rifat Kayumov, Artem Klyubin, Andrey Konchenko, Alexey Yudin, Schlumberger; Alexander Khalzov, Vladislav Firsov, Evgeniy Nikulshin, Zdenko Kaluder, Suleyman Sitdikov, Rosneft

Abstract

The Volga-Urals basin is one of the largest oil-producing regions in western Russia. The most prolific wells are producing from Devonian formations characterized by light crude oil with high bubblepoint pressure. Today, most of the Devonian reservoirs are depleted and produce at bottomhole flowing pressure below bubblepoint pressure, which yields multiphase and non-Darcy flow in hydraulic fractures, drastically decreasing production. As a result, conventional hydraulic fracturing treatments are less effective. To regain fracturing treatment efficiency, the restrictions to hydrocarbon flow inside the fracture must be minimized. To account for this, a new method of fracture conductivity generation was introduced.

Channel fracturing creates open pathways inside the fracture, enabling infinite fracture conductivity. Channels are created by discontinuous proppant feeding at surface into viscous fracturing fluid. Dissolvable fibers are added to the slurry to separate proppant structures and prevent them from settling during treatment. Proppant structures act as bridges inside fractures; voids between them are essentially stable channels connected along the entire length of the fracture.

While channel fracturing has already been implemented successfully in many places around the world, the fracturing conditions of Volga-Urals Devonian formations were still new for this technology. The Volga-Urals region is well known for high tectonic stresses and low fracturing-fluid efficiency. While channel fracturing treatments are being designed and pumped in a regime without tip-screenout (TSO) in other locations, channel fracturing treatments in Devonian formations often showed significant TSO. Production analyses showed consistent productivity increases, and in most cases, 2 folds higher compared with offset wells where conventional fracturing technology was used.

After the success of the pilot campaign, proppant flowback was resolved by incorporating a rod-shaped proppant as a tail-in stage of channel fracturing schedules. The nonspherical shape of the proppant increases internal friction between the particles and mechanically holds them in place. In addition to improving proppant flowback control, the combination of technologies maximized conductivity of the near-wellbore area which connects channels and the wellbore. The success of more than 30 of such fracturing treatments expanded the pool of candidates for channel fracturing with rod-shaped proppant to meet the challenges of similar complex geological conditions.

Introduction

The Volga-Urals basin is one of the oldest and largest oil-producing regions in Russia. The first oil on the western edge of Ural Mountains was discovered in 1929. By 1977, decades of climbing production from the Volga-Urals basin were over, and production started to decline fairly sharply. The sharp decline mainly occurred because most of the resources are concentrated in a few extremely large fields and the rest are divided among a very large number of small fields. All giant fields were discovered before 1960 and had become mature by late 1970, while newly explored oil fields were too small to reverse the basin’s production decline. Today, the Volga-Urals basin is no longer Russia’s premier producer, but the basin is still responsible for nearly a quarter of Russian oil supply (Grace 2005). It is presently a stable, if declining, region that is favorably situated in the middle of the Russian refining and energy transportation infrastructure.

The Orenburg region, an important component of the Volga-Urals basin, is located near other oil and gas producing provinces: Bashkortostan, Tatarstan, Samara region, and north Kazakhstan. There are more than 100 oil fields scattered in the western part of the Orenburg region. Most of the oil fields in the region currently belong to the Rosneft oil company, and this paper focuses on these fields. The geological structure of the Volga-Urals basin is very complex; the wells are producing
from tens of Permian, Carboniferous, and Devonian reservoirs. In the Orenburg region, the most prolific wells are producing from Devonian sandstone formations (mainly the Dkt, D1, and D3). These formations are characterized by light crude oil with high gas/oil ratio (GOR) and bubblepoint pressure ($P_b$). The properties of some oil fields producing from Devonian formations are presented in Table 1.

<table>
<thead>
<tr>
<th>Oil field</th>
<th>Formation</th>
<th>Average TVD, m</th>
<th>GOR, $m^3/m^3$</th>
<th>$P_b$, bars</th>
<th>Oil viscosity, cP</th>
<th>API gravity</th>
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<td>Garshinskoe</td>
<td>D3</td>
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<td>476</td>
<td>242</td>
<td>0.22</td>
<td>48</td>
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<tr>
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<td>198</td>
<td>0.18</td>
<td>42</td>
</tr>
</tbody>
</table>

The first oil from the Devonian formations in the Orenburg region was produced in 1952, and the majority of the Devonian reservoirs are depleted now. Fig. 1 shows current reservoir pressure depletion status for the same five reservoirs described in Table 1. Vostochno-Kapitonovskoe field is a green field that was put into production recently and still has relatively high reservoir pressure, 76% of initial pressure. The other four oil fields are significantly depleted and have current reservoir pressure less than 50% of the initial pressure. This depletion process, in conjunction with high $P_b$, leads to the fact that more than a half of the Devonian wells from the five studied oil fields are working now with reservoir pressure ($P_{res}$) less than $P_b$ (Fig.2), and 94% of wells are working with bottomhole flowing pressure ($P_{wf}$) less than $P_b$. This promotes free-gas separation from the liquid phase causing multiphase flow in the fracture.

![Fig. 1—Reservoir pressure depletion for the five studied oil fields.](image)

![Fig. 2—Comparison of pressures in the five studied oil fields.](image)

Multiphase flow and the accompanying non-Darcy behavior fatally affect fracture conductivity and overall well performance. The multiphase flow effect causes additional pressure drop inside the formation and fracture due to saturation changes, relative permeability effects, and complex flow regime. For an oil well producing below the bubblepoint, the presence of free gas will also drastically increase fluid velocities in the fracture, which means non-Darcy behavior will occur. Thus, multiphase flow and non-Darcy effects are closely interconnected. It is very complicated to measure the effects of multiphase flow and non-Darcy behavior. Several researchers have attempted to quantify the effect of multiphase flow in fractures with laboratory work or by analyzing production data. While these authors report differing results regarding the absolute value of the conductivity loss, all conclude that the effects are substantial and should not be ignored (Vincent et al. 1999).

Kayumov, Konchenko et al. (2012) provided an example of the detrimental effect on production from fractured wells with bottomhole flowing pressure below bubblepoint pressure in Garshinskoe oil field. Fig. 3 presents a post-fracturing productivity index (PI) value for the wells working from the D3 formation in Garshinskoe oil field. All wells are placed in order of descending $[P_{wf} - P_b]$ value. In this example, only six wells on the far left side of the chart show $P_{wf}$ higher than $P_b$; all other wells are working below $P_b$, and the level of difference between $P_{wf}$ and $P_b$ is shown by blue dots. It is clearly seen
that PI is drastically decreasing from left to right with more negative $[p_{wf} - p_b]$ value. This productivity decrease is directly related to non-Darcy and multiphase flow effects inside the fractures. Some high PI values in the middle of the chart probably relate to the fact that reservoir pressure and $p_{wf}$ in the mature fields in the area are rarely measured, and even a small difference in these values can sometimes result in a large variance in PI calculation. But even with these uncertainties, the overall trend is clear. A few other examples of production drop for wells produced below bubblepoint pressure were published by Dedurin et al. (2006).

Fracturing is a standard completion method for all wells producing from Devonian formations in the Oreburg region. Experience has shown that these fracturing treatments usually have some specific differences from fracturing in other parts of Russia. Low fracturing-fluid efficiency forces the use of large pad volumes (Fig. 4) and the use of special fluid loss additives in the fracturing fluid. These actions decrease the risk of premature screenout but lead to significant reduction of fracture conductivity, effective fracture half-length, and, subsequently, decrease in post-fracturing production. Even with large pad fluid volume, almost all fracturing treatments in Devonian sandstone formations were finished in tip-screenout (TSO) regime when proppant starts to pack in the fracture during the treatment. This proppant packing process can be observed by significant net pressure increase during main fracturing treatment. Fig. 5 shows that average net pressure increase between a minifrac operation and the subsequent conventional main fracturing is 80 to 100 bars for all fields excluding Vostochno-Kapitonovskoe where reservoir pressure depletion is less serious. Thus, the majority of fracturing operations in Devonian formations are finished in TSO regime in spite of the use of large pad volumes.
Just 5 years ago, proppant flowback was not frequently observed in Devonian formations. But recently, the operating company noticed that the proppant flowback problem became more and more pronounced with time. The reason for this occurrence is reservoir pressure depletion and severely increased multiphase flow inside the fracture. As mentioned previously, multiphase flow increases the fluid velocity in the fracture, thus increasing the drag forces pushing proppant out of the fracture during production. The proppant flowback problem cannot be ignored, and special technologies to minimize proppant flowback should be implemented in each fracturing treatment.

To overcome the increasing negative effect of multiphase and non-Darcy flow on fracture conductivity, channel fracturing technology was implemented in Devonian formations in the Orenburg region. Although channel fracturing has already proved its outstanding performance in different places around the world, conditions of Volga-Urals Devonian formations were still new for this technology (i.e., significant proppant packing is not typical for channel fracturing), and it was important to evaluate productivity of the pilot wells stimulated with new technique. For many treatments in the fracturing campaign described in this paper, channel fracturing was enhanced by rod-shaped proppant to eliminate potential proppant flowback problems and maximize conductivity of the near-wellbore area.

Rod-Shaped Proppant
The recently developed rod-shaped proppant had already been implemented in several countries around the globe with consistent success in increasing stimulation efficiency. Fig. 6 shows the grains of rod-shaped proppant, which is, in principle, a new product compared to the proppant made up of spherical grains that is commonly used in stimulation industry. The size of the particles is essentially large; the diameter of the cylinder base is similar to 12/16 mesh size, which corresponds to the largest proppants currently used in Russia. Random distribution of such cylindrical particles increases final pack porosity, which results in improved pack permeability and better fracture cleanup from polymers. Details of rod-shaped proppant development were provided by McDaniel et al. (2010); they also describe the first field implementation that proved the theory and laboratory modeling by significant well productivity increase when the new type of propping agent was used for fracturing. Proppant flowback control is another important benefit of the rod-shaped proppant. Rod-shaped particles interlock in a consolidated structure that appears to be highly resistant to drag forces (see Fig. 7). As opposed to resin-coated proppants, rod-shaped particles hold each other by mechanical means, not chemical bonds. Thus, pack stability is independent of temperature or time of activation which can be limitations for chemical-based techniques. Field implementation of the new product as a proppant flowback prevention mechanism was reported by Edelman et al. (2013) who described fracturing treatments in the Arta heavy oil field, where conventional proppant pack led to severe flowback within days after being put in production. Eighteen treatments utilizing rod-shaped proppant were successfully optimized to eliminate flowback issues by pumping rod-shaped particles as a tail-in stage in the amount of 25% and higher from the whole proppant mass.

The depleted formations of Orenburg area in which multiphase flow caused production decline and severe proppant flowback problems were considered as first candidates for rod-shaped proppant implementation in Russia. The trial campaign of the new proppant in the Orenburg area was described in detail by Kayumov, Konchenko et al. (2012) The campaign proved the advantage of rod-shaped particles over conventional spherical ones in both proppant flowback prevention and significant productivity gain. No proppant flowback was reported after 10 trial treatments. Consistent results in the wells’ productivity increase (from 26% up to 67%, depending on the field) when compared to offset wells stimulated with conventional proppants were reported for Vakhitovskoe, Vostochno-Kapitonovskoe, and Lebyazhinskoe oil fields. This paper concentrates on the channel fracturing campaign initiated in 2011 in several fields around Orenburg to further improve fracture conductivity and well production.

Channel Fracturing Technology
A fundamentally new concept of fracture conductivity generation forms the basis for channel fracturing technology development. Proppant is still used with new stimulation technique to keep fracture walls separated after treatment, but now it is placed heterogeneously, as shown in Fig. 8 (right). Proppant structures are created with surface equipment by pulsating
proppant concentration (Fig. 9). Further flow of proppant structures along the tubular and fracture is supported with degradable fibrous material which keeps the proppant structures consolidated and prevents settlement. After fracture closure on proppant structures, the voids between remain open for flow, and thus channels are formed along the fracture to deliver hydrocarbons during the production life of the well. Open channels increase fracture conductivity by orders of magnitude, which significantly improves fracture cleanup from treatment fluids and polymer residues resulting in higher effective fracture half-length. Effective half-length and improved conductivity of the fracture lead to significant production benefits in wide range of formations.

![Fig. 8—Concept of channel fracturing when proppant is distributed heterogeneously inside fracture (right) as opposed to a tight proppant pack of standard fracturing technique (left).](image)

![Fig. 9—Schematic of proppant concentration pulses during channel fracturing treatment.](image)

Channel fracturing concepts and details were described by Gillard et al. (2010); within 3 years the technique was implemented in many parts of the world with consistent success of placement reliability (avoiding screenouts) and production increase over conventional fracturing technologies. The statistical overview of performed treatments and more details on mechanisms of channel fracturing were discussed by Medvedev et al. (2013). Clean pulses around the proppant ensure reliable placement of channel fracturing treatments. The screenout ratio is less than 0.1% according to the worldwide statistics of more than 10,000 operations, which represents a significant advantage of the new technique for Russian fields, where large-size proppants are pumped for conductivity optimization which leads to high screenout ratios (from 5% up to 10% depending on the fields). To date, more than 100 channel fracturing treatments have been successfully placed in Russia without a single screenout.

One project completed in Western Siberia deserves particular attention. As reported by Sadykov et al. (2012), channel fracturing treatments were performed in a Jurassic formation of remote Taylakovskoe field with oil and formation characteristics similar to those of the Orenburg area (medium-permeability sandstones). The authors reported a channel fracturing advantage of 44% in oil rate increase when compared to standard stimulation technologies. When the PI was calculated (liquid rate over drawdown) per well, an average advantage of 94% over the PI values of standard fracturing techniques was the result of implementation of the new technique in a pilot campaign of 10 wells. Screenout reduction from an average of 10% in Taylakovskoe down to zero had a significant impact on workover operations and overall field development considering the remoteness of the location and associated costs of cleanout operations.
Considering the pilot campaign of channel fracturing in the Orenburg area, both screenout reduction and production increase were set as primary targets. The Volga-Urals Devonian formations are well suited to the application of the new technology as they have high enough temperature to ensure timely degradation of fibrous material. Infinite conductivity of channels inside fractures should provide significant production benefits over conventional proppant pack in depleted reservoirs with strong multiphase and non-Darcy flow.

Of particular importance is the channel fracturing schedule which calls for proppant pulsation to continue during the entire treatment, except at the last tail-in stage (Fig. 9), at which time several tons of proppant (normally 3 to 4 depending on formation thickness) are pumped continuously at constant concentration. The tail-in stage serves as a reliable near-wellbore pack to hold fracture walls open. This area has increased stresses, and the risk of pinching is increased. Normally for channel fracturing, tail-in is pumped with the strongest and most permeable proppant to maximize fracture conductivity. Proppant flowback can still be the problem for the tail-in stage since the flow velocities reach maximum values in the near-wellbore area. The stability of the proppant pack in the tail-in must be designed accordingly. Since both trial campaigns with channel fracturing technology and rod-shaped proppant showed positive results, it was decided to combine the two technologies by using rod-shaped particles in tail-in stage.

**Tailing Channels with Rod-Shaped Proppant**

The first combined treatments in the Orenburg area were reported on by Kayumov, Konchenko et al. (2012), who showed the clear advantage of channel fracturing technology with rod-shaped particles in the tail-in stage in terms of productivity when compared to standard fracturing techniques. Later implementations of channel fracturing were extended to new fields and wells with increased risks (such as deviated wells and sidetrack applications), with consistent success; these are discussed below. At the same time, field implementation of combined channel fracturing and rod-shaped proppant was executed in Egyptian locations. Abdelhamid et al. (2013) reported increased well productivity after implementation of the combined technology compared to standard stimulation techniques in Silah field. A significant advantage of channel fracturing tailored with rod-shaped proppant was in the elimination of screenout; screenout occurred in more than 45% of the standard fracturing treatments according to the statistics over 2 years. Proppant flowback was another common problem of hydraulic fracturing in Silah field; this was solved by rod-shaped proppant at the tail-in stage. Gawad et al. (2013) described their trial campaign of combined channel fracturing and rod-shaped proppant at tail-in. Seven wells in Qarun fields in the Western Desert of Egypt were compared against 12 offset wells stimulated with conventional techniques to conclude an 89% average productivity advantage of the new combined stimulation technology after 45 days; this production difference increased over time. Zero screenouts and zero flowback issues were also reported. Samir et al. (2013) described the challenges of Abu Roash formation development in Abrar field (also located in the Western Desert of Egypt). The formation is represented by laminated siltstones. Although the initial production increase was significant after conventional stimulation, a decline followed shortly, leading to only a small cumulative production gain. As a result of a six-well channel fracturing campaign, Abrar field has become an economic field to produce from, with an over 50% increase in production and 50-fold increase in its proven reserves. Rod-shaped proppant was used in all treatments to avoid proppant flowback.

This paper presents further examples of the advantages of combining channel fracturing and rod-shaped proppant by providing details on treatment execution and productivity analysis from more than 30 stimulated wells in five oil fields of the Orenburg area.

**Case Study: Zagorskoe Oil Field**

More than 30 channel fracturing treatments were performed in the Orenburg area. Most of them (68%) were tailed-in with use of unconventional rod-shaped proppant. Kayumov, Klyubin et al. (2012) described the basic candidate selection requirements for channel fracturing that were used in Russia:

- Cased-hole wells with no perforation in target zone to allow cluster perforation
- Certain degree of rock stiffness, a ratio of Young’s modulus over closure stress above 275
- Net height over 6 m.
- No additional risks of breaking into water-bearing formations in case of fracture height growth or this risk is acceptable by the nature of those formations
- Well deviation of less than 15° in the target interval to minimize risk of fracture plane misalignment with wellbore
- Lowest possible formation lamination of the pay interval

Some of the candidate selection and design considerations remained unchanged from the list above, but with growing experience and field trials, several of them no longer limit application of the technology. At present, well deviation is not limited to 15°. Successful channel treatments (in both operational and productivity terms) were performed in wells with deviation angels in the pay zone over 30°. The clustered perforation requirement is still present as dictated by the technology concept, but a few operations with continuous perforation in the pay zone were performed with positive results.

Zagorskoe is the first field where channel fracturing was used in the Volga-Urals region. The field characteristics are presented in Table 1. This field was chosen for detailed analysis because all possible combinations of treatments were performed in the area (conventional fracturing, channel fracturing, and channel fracturing enhanced by rod-shaped proppant). In addition, the availability of long-term production data allows making a conclusive analysis. In general, the field is fairly uniform across the area. All treatments under consideration (see Fig. 10) are located in close proximity.
The target D1 formation consists of thick clean sandstone block with minor lamination. Formation net height ranges from 12 to 26 m (see Fig. 11). Generally, all jobs (both channel and conventional fracturing) were performed using similar volume of the intermediate-strength proppant (ISP), with a few cases in which smaller treatments were done in close proximity to the reservoir boundary (wells 3606 and 3623).

Typically, fracturing in deep Devonian formations is associated with high risk of screenout due to high anticipated stresses and extremely low fracturing-fluid efficiency. In this case, having all mitigation measures in place is very critical. Usually, these measures include lowering maximum proppant concentration to 800 to 1000 kg/PA and pumping high-viscosity fluids. On the other hand, all of these jeopardize well productivity performance after the fracturing job.

Minifrac treatments are common practice in the area and serve as a source of valuable formation data (minimum in-situ stress, fluid efficiency, net pressure) that decrease the uncertainty of well conditions and aid in fine-tuning the fracturing job design to minimize screenout risk. The typical minifrac consists of injection and calibration tests (with proppant and crosslinked fluid) as shown in Fig. 12. As seen from the figure, the formation exhibits very high fluid leakoff. Treating
pressure drops from 182 bar to 0 in less than 3 minutes after the injection test. Although fluid leakoff decreases after the calibration test, fluid efficiency is still extremely low (11%). Formation parameters like this call for a large volume of pad stage and use of fluid loss agents that significantly impact post-fracturing production.

**Fig. 12**—Typical mini-frac treatment and analysis (G-function plot).

![Graph showing pressure, proppant concentration, slurry rate, and time with markers indicating injection and calibration stages.]

**Fig. 13**—Temperature log and built stress profile.

In several cases, the minifrac was supplemented with a temperature log. Temperature measurements immediately after the minifrac show areas of greatest cool down of the formation, help to identify potential crossflows behind the casing, and serve as reference points to fracture height determination for building the formation stress model. **Fig. 13** shows modeled fracture behavior during the calibration stage and the corresponding formation cool-down effect measured 2, 4, and 6 hours after the job. As seen, deflection of temperature from the base static bottomhole temperature is in line with modeled fracture height propagation. Thus, the stress profile is validated, not only by pressure matching of calibration stage in the fracturing simulator, but also by independent direct measurement.

Our worldwide experience with channel fracturing treatments showed that risk of premature screenout is very low...
because of the lower proppant bridging tendency. This let us design treatments with significantly higher proppant concentrations: from 800 to 1000 kgPA normally pumped on conventional jobs to 1200 to 1400 kgPA.

A typical channel fracturing treatment with rod-shaped proppant in the tail-in stage is shown on Fig. 14. As seen, the tail-in stage is small in comparison with the rest of the treatment, so little influence on production was expected. But, in terms of fracture reliability and proppant flowback control, this stage has critical importance. Zero cases of proppant flowback were reported after the treatments performed with the use of unconventional rod-shaped proppant.

Fig. 14—Typical channel fracturing treatment enhanced by unconventional rod-shape proppant.

As stated above, all fracturing jobs shared a similar amount of proppant pumped during the main stage, and wells are located close to each other, so changes in productivity in this case could be attributed to the influence of the technology used. The PI normalized by net height ($h_{net}$) was used to evaluate the impact of channel fracturing on production results in Zagorskoe oil field. Fig. 15 depicts PI normalized over net height plotted against the time scale. Green lines represent conventional fracturing jobs, and blue and brown lines represent channel treatments and treatments enhanced by rod-shaped proppant (brown lines). As seen from Fig. 15, almost all the wells treated with channel fracturing have higher PI/$h_{net}$ values.
proving that channels inside the fracture play a significant role in productivity. The average normalized PI over 150 days showed a 102% increase over conventional treatments. One of the first wells stimulated with channel fracturing (well 3601) still produces 130 m³/day of fluid and 101 t/day of oil after 2.5 years of production. This proves that channels do exist and are stable over the extended period of time.

**Benefits**

As previously mentioned, apart from production, major screenout reduction is a second main benefit of the channel fracturing technique. Since 2007, 174 conventional fracturing treatments have been pumped in the Devonian formations of the above-mentioned oil fields. A total of 14 screenouts (8%) has been recorded versus a zero screenout ratio for the total of 32 channel fracturing treatments performed between 2011 and 2013. Because of the elimination of screenout, a general consideration for channel fracturing treatment design is increasing the aggressiveness of the pumping schedule (e.g., more rapid proppant concentration ramp, increased maximum concentration of proppant, and increased job volume) to enhance fracture geometry without having a screenout risk. Fig. 16 shows the average difference between proppant ramp and concentration for conventional and channel fracturing treatments in Devonian formations. The x-axis represents relative pumping time, where 0% represents the time when proppant starts to be pumped and 100% is the end of treatment. The figure shows that proppant concentration for channel fracturing is increasing much faster at the beginning of treatment and reaches a higher value at the end of treatment than for conventional fracturing: the average maximum proppant concentration is 1000 kgPA for conventional fracturing and 1200 kgPA for channel fracturing treatments. In general, for conventional fracturing, increasing conductivity and fracture width are major design criteria for multiphase flow conditions. Increasing propped fracture width is also an essential design criterion for channel fracturing as increasing the width helps to have better stability of the channels. Fig. 17 shows the distribution of propped fracture width for channel fracturing and conventional treatments. Each dot represents a separate fracturing treatment: blue dots represent channel fracturing and black dots represent conventional fracturing. It is apparent that overall width for channel fracturing is measurably higher compared to that for conventional fracturing because of the ability to pump bigger job volumes with higher proppant concentration.

![Fig. 16—Comparison of average proppant concentration for conventional and channel fracturing in the Orenburg regions](image1)

![Fig. 17—Comparison of propped fracture width for conventional and channel fracturing in the Orenburg region.](image2)

To compare the channel fracturing design approach with conventional fracturing in different fields, proppant mass per treatment was normalized on average proppant mass pumped for conventional treatment in a particular field. Normalizing numbers is essential as each of five oil fields in this study had slightly different treatment and fracturing design parameters. For comparison purposes, channel fracturing treatment proppant mass was divided by 0.55 because proppant mass used for channel fracturing treatment is equal to 55% of proppant used for conventional treatment (channel fracturing process implies 50% of clean pulses and 50% of proppant pulses + ~5% proppant mass for the tail-in stage). Fig. 18 compares normalized proppant mass for both treatment types. It is clear that channel fracturing allows placing almost twice the equivalent proppant mass compared to conventional fracturing. On the other hand, Fig. 19 shows the increase in normalized instantaneous shut-in pressure (ISIP) from calibration to the main fracturing treatment (similar to proppant mass, each value was normalized on average ISIP increase for each of five oil fields). ISIP increase is an indication of net pressure gain due to either proppant packing or bridging in the fracture. In spite of the doubled job volume (Fig. 18), the ISIP increase for channel fracturing demonstrates the same average number as for conventional jobs. This indicates less proppant packing or bridging during the channel fracturing treatment. Medvedev et al. (2013) described this feature of channel fracturing experimentally. The elimination of screenout makes channel fracturing the preferred treatment in cases of high screenout risk (e.g., formations in a compressional environment with high tectonic stress, hydraulic width limited treatments, excess or uncontrolled leakoff environment). Sadykov et al. (2012) have demonstrated that channel fracturing can be a valuable option for production enhancement with refracturing treatments with reduced risk of screenout.
It was previously demonstrated that the effect of adding a fiber material to crosslinked fluid is the reduction of total friction pressure by an average of 17 to 29% depending on proppant concentration (Yudin et al. 2013). The fiber-laden fluid described in this paper used similar fibrous material under the same concentrations as channel fracturing. In the Orenburg region we have experience with pumping conventional fracturing, fracturing with fiber-laden fluid, and channel fracturing. With available data it was possible to investigate friction for each type of treatments. The comparison was carried out using measured bottomhole pressure data and surface pressure data for a total friction calculation. Proppant friction data has been calculated as the friction difference between proppant slurry stages and the pad stage without proppant. That means it may include some uncertainties as loss of friction pressure on proppant near wellbore and variations of fluid friction during the job that may occur due to fluid temperature changes or a slight change in additive schedule impacting fluid friction behavior. All of the fracturing in the Orenburg region are currently carried out through 74-mm inside diameter (ID) tubing, so friction calculations have been performed in terms of pressure gradient per meter of fracturing string. Based on the data acquired in this study, it has been confirmed that adding fibers to crosslinked fluid may significantly decrease friction pressure on a proppant stages, up to 18% with higher proppant concentrations (Fig. 20). It also shows that proppant friction for channel fracturing treatments is up to 41% less compared to that in conventional fracturing. The effect of friction reduction on channel fracturing treatments is also a consequence of both having less proppant in a tubing due to the pulse pumping and adding fiber material to the fluid. Unfortunately, this effect does not lead to a decrease in treatment pressure and lower hydraulic horsepower (HHP) requirements as surface pressure is being compensated for by lower hydrostatic pressure for pulse proppant pumping versus continuous pumping. On the other hand, understanding surface pressure behavior is an essential part of the fracturing design process and designing equipment requirements.

**Production Results**

A production study was performed for the first 20 wells stimulated with channel fracturing in five oil fields: Garshinskoe, Lebyazhinskoe, Shirokodolskoe, Vostochno-Kapitonovskoe and Zagorskoe. These wells had enough production data at the time when analysis was performed. The majority of these 20 wells were treated with rod-shaped proppant at the tail-in stage.
Daily production data for these wells were gathered and compared with production from the 32 closest offset wells after conventional fracturing. The analysis is based on the PI value normalized on the net pay thickness ($h_{\text{net}}$). Net pay thickness was derived from log data. Robust permeability values were not known for most of the wells, so permeability could not be used for further data normalization. The results of the performed analysis for each oil field can be seen in Table 2. Overall results are very positive; productivity increased more than twice compared with conventional fracturing in three out of five fields: Garshinskoe, Lebyazhinskoe (consists of two separated domes), and Zagorskoe.

### Table 2—Post-Fracturing Production Comparison

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<tr>
<th>Oil field and formation</th>
<th>Average $\text{PI}/h_{\text{net}}$ for channel fracturing, m$^3$/day/bar/atm</th>
<th>Average $\text{PI}/h_{\text{net}}$ for conventional fracturing, m$^3$/day/bar/atm</th>
<th>$\text{PI}/h_{\text{net}}$ incremental, %</th>
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<tbody>
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<td>Garshinskoe D3</td>
<td>0.5417</td>
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<td>-16</td>
</tr>
<tr>
<td>Shirokodolskoe D3, South-West</td>
<td>0.1439</td>
<td>0.1742</td>
<td>-17</td>
</tr>
<tr>
<td>Vostochno-Kapitonovskoe D3, natural flowing</td>
<td>0.6916</td>
<td>0.5451</td>
<td>27</td>
</tr>
<tr>
<td>Vostochno-Kapitonovskoe D3, ESP</td>
<td>0.1499</td>
<td>0.0786</td>
<td>91</td>
</tr>
<tr>
<td>Zagorskoe D1</td>
<td>0.2655</td>
<td>0.1321</td>
<td>102</td>
</tr>
</tbody>
</table>

Wells treated with channel fracturing in Shirokodolskoe oil field were located on opposite sides of the field and were also analyzed separately. The northeast side of Shirokodolskoe field is very heterogeneous and many wells drilled in this part of reservoir cannot produce, even after fracturing treatments. Channel fracturing was performed on the well located at the edge of Shirokodolskoe field; the three closest offset wells could not produce after fracturing and were abandoned. But the well stimulated with channel fracturing treatment enhanced by rod-shaped proppant started to produce at a commercial rate with productivity comparable (lower by only 16%) to wells located in more prolific part of the northeast side of Shirokodolskoe field. In spite of the negative number, this was considered as a success. On the southwest side of Shirokodolskoe field, one well treated with channel fracturing and rod-shaped proppant in the tail-in stage was compared with the three closest offset wells fractured conventionally. A direct comparison showed that the channel fractured well produced slightly less (minus 17%) than offsets. But two out of three offset wells were fractured few years ago, when reservoir pressure was higher than bubble point pressure. Now, reservoir pressure has fallen below producing pressure, and some of the wells have enough capacity to flow naturally; all wells in other fields produce only with electric submersible pumps (ESP). Usually, Devonian wells that flow naturally can produce at much higher PI than wells that produce with ESP. The suspected reason is that the naturally flowing wells are producing at much lower pressure drawdown, and thus $p_w$ can be maintained above $p_h$, thus eliminating non-Darcy flow in the reservoir and fracture. For comparison purposes, naturally flowing wells and wells producing with ESP on Vostochno-Kapitonovskoe field were analyzed separately. The results in Table 2 show that channel fracturing provides production benefits for both well types, but in the case of wells with ESPs, the productivity increase is higher and very consistent with productivity increase numbers from the very successful Garshinskoe and Zagorskoe oil fields. Again, this proves that channel fracturing enhanced by rod-shaped proppant significantly minimizes non-Darcy and multiphase flow effects associated with production above bubble point pressure, which is particularly the case for the wells produced at high pressure drawdown with ESP.

To visualize the benefits of channel fracturing treatments over conventional fracturing for all analyzed wells (20 channel fracturing and 32 conventional fracturing), $\text{PI}/h_{\text{net}}$ values for each well were further normalized on the average $\text{PI}/h_{\text{net}}$ value for the best well for each respective oil field. This was done because all five fields have different reservoir properties (Table 1), and direct comparison of $\text{PI}/h_{\text{net}}$ values for all wells is inconclusive since some fields may produce at higher productivity due to better reservoir quality. All normalized $\text{PI}/h_{\text{net}}$ values were plotted on the same chart (Fig. 21): light blue lines represent each channel fractured well’s productivity; light red lines represent each conventionally fractured well’s productivity; the wide blue line represents the average productivity value for channel fracturing; and the wide red line represents the average productivity value for conventional fracturing. It is apparent from the Fig. 21 that the majority of blue lines are located at the upper part of the chart, and most of the red lines are located at the bottom of chart (i.e., have low productivity). On average, the productivity of wells after channel fracturing is 64% higher than productivity after conventional fracturing. It is worth mentioning that most of the light red lines that are located on the upper part of Fig. 21 are...
from Shirokodolskoe field, and the reasons for this were described previously in this section. Without wells from Shirokodolskoe field, average productivity after channel fracturing is 99% higher than after conventional fracturing; in other words, the combination of channel fracturing with rod-shaped proppant doubles a well’s productivity.

The productivity comparison of channel fractured wells with and without rod-shaped proppant did not provide clear conclusions; average productivity is close. One of the reasons is that there were not many treatments pumped without rod-shaped proppant (only 6 out of 20 analyzed) as proppant flowback was a serious concern and rod-shaped proppant significantly outperforms any other proppant flowback control methods (McDaniel et al. 2010; Kayumov, Konchenko et al. 2012; Edelman et al. 2013; Abdelhamid et al. 2013; Gawad et al. 2013). Also, the tail-in stage is very short and designed just to fill a fracture on a distance of few meters from wellbore. Such a short proppant pack should not considerably decrease overall average fracture conductivity, and the production difference can be too small to be detected on the field level. But what is really important is that no proppant flowback have been observed in any wells treated with channel fracturing enhanced by rod-shaped proppant, and this combination provides a comprehensive solution for all Devonian reservoirs in Volga-Urals region of Russia.

Conclusions

Implementation of channel fracturing enhanced by rod-shaped proppant brings substantial value for depleted Devonian formations in the Orenburg region of Russia. Highly conductive channels inside the proppant pack significantly minimize influence of multiphase and non-Darcy flow to overall production. Rod-shaped proppant in the tail-in stage provides the highest possible conductivity in the critical near-wellbore region and eliminates the potential proppant flowback problem.

More than 30 channel fracturing treatments have been successfully pumped in the Volga-Urals Devonian formations during the fracturing campaign described in this paper. Rod-shaped proppant was used as a tail-in stage on 68% of all channel fracturing jobs. The following results of the campaign have been reported:

1. Average productivity after channel fracturing is 99% higher than after conventional fracturing in the closest offset wells; in other words, the combination of channel fracturing with rod-shaped proppant doubles a well’s productivity.
2. The two-fold productivity increase and long-lasting treatment results provide confidence in the stability of the channels in challenging areas with low fracturing-fluid efficiency and long tip-screenout regime during the main fracturing treatment and, subsequently, very high net pressure.
3. No single screenout was observed in channel fracturing treatments; the screenout ratio for Devonian formations with conventional fracturing treatments was 8%.
4. The absence of screenout with channel fracturing allows us to design more aggressive fracturing treatments compared to conventional jobs pumped previously: a larger proppant mass, higher average and final proppant concentration, aggressive proppant ramp, and larger propped width. In spite of the aggressiveness of treatment designs, observed net pressure did not increase over conventional treatments because there is less tendency for proppant packing in the fracture.
5. Channel fracturing decreases proppant friction pressure by 41% compared with conventional fracturing due to addition of fibrous material during pumping and the pulsating nature of channel fracturing when proppant pulses alternate by clean fluid pulses.

6. No proppant flowback issues were observed in channel fracturing treatments in which rod-shaped proppant was used in the tail-in stage.

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References


Nomenclature

\( h \) effective reservoir thickness, m
\( Jd \) dimensionless productivity
\( k \) permeability of porous media, \( m^2 \) or \( mD \)
\( \bar{P}_r \) average reservoir pressure, atm
\( P_{wf} \) bottomhole flowing pressure, atm (bar)
\( q \) fluid production, \( m^3/day \)
\( \mu \) fluid viscosity, Pa·s

SI Metric Conversion Factors

\[ \text{atm} \times 1.013 \, 250 \times 10^5 = \text{Pa} \]
\[ \text{bar} \times 10^5 = \text{Pa} \]
bbl × 1.589 873 E−01 = m³
cp × 1.0* E−03 = Pa·s
ft × 3.048* E−01 = m
ft² × 9.290 304* E−02 = m²
ft³ × 2.831 685 E−02 = m³
°F ((°F−32)/1.8 = °C
gal × 3.785 412 E−03 = m³
lbm × 4.535 924 E−01 = kg
psi × 6.894 757 E+00 = kPa

*Conversion factor is exact.