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Field experiments on multi-stage chemical diversion in low-permeability HPHT reservoirs

Tianbo Liang[a], Dongya Wei[a], Fujian Zhou[a,*], Xiuhui Li[a], Lishan Yuan[a], Bo Wang[a], Jun Lu[b,**]

[a] State Key Laboratory of Petroleum Resources and Prospecting, China University of Petroleum (Beijing), Beijing, 102249, China
[b] McDougall School of Petroleum Engineering, University of Tulsa, USA

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ABSTRACT

Efficiently producing gas from low-permeability reservoirs relies on a complex and dense fracture network. Since mechanical plugs or isolation tools become less reliable at high pressure and high temperature, chemical diversion is likely one of the most promising stimulation methods for the multi-stage hydraulic fracturing. To meet field operation needs, a series of diverters has been developed; they have different shapes and sizes, and can be applied in reservoirs with temperatures up to 200 °C and pressures up to 140 MPa. After the stimulation, diverters can degrade at the reservoir condition, leaving no residue that causes formation damage. Laboratory evaluation methods were introduced that could obtain the plugging process and plugging efficiency of diverters with different shapes and sizes, as well as the initiation of secondary fractures under tri-axial stress conditions. However, due to the limitation of sample dimensions, these methods still cannot capture the plug formation and fracture initiation in the middle section of previously generated fractures, and thus unable to evaluate the intra-stage diversion that is more crucial to the generation of the complex fracture network. Therefore, different diversion treatments with different diverters were tested and compared in 43 vertical wells in the Tarim Basin with reservoir temperatures ranging from 120 °C to 181 °C. Results showed the successful operations of both intra-stage and inter-stage diversions during the multi-stage diversion treatment, where the former one seemed more effective on production enhancement. Moreover, the fiber-shaped diverters could enhance the formation of complete plugs in the previously generated fractures, and allow more secondary fractures to branch off from these fractures to achieve a better stimulation. Findings of this paper could provide crucial guidance on optimizing the diverters for stimulating the low-permeability reservoirs.

1. Introduction

In the U.S., although the hydraulically-fractured reservoirs contributed more than 50% of oil production and 75% of gas production (EIA, 2018), their estimated ultimate recovery rates (EUR) are likely less than 10% (oil reservoirs) and 25% (gas reservoirs) (EIA, 2015; H. Wang et al., 2016b; Wachtmeister et al., 2017; Hu et al., 2018). To enhance the recovery rate of low-permeability reservoirs like shales, a complex and dense fracture network needs to be created to expose the reservoir rock. However, fracture propagation can change the stress field and result in the "stress shadow" effect that hinders the formation of the complex and dense fracture network (Roussel and Sharma, 2011). Within one fracturing stage, the growth of one fracture can limit the growths of its neighboring fractures (Lecampion et al., 2015; Wheaton et al., 2016), or divert its neighboring fractures that further causes fracture merging (Manchanda and Sharma, 2014; Wu and Olson, 2015, 2016; Kresse et al., 2017). Therefore, although hydraulic fractures are designed to have similar dimensions among different clusters and stages, they seldom have similar lengths nor propagate uniformly from the wellbore; this has also been supported by the field observations that approximately 80% of production comes from only 20% of the fractures (Miller et al., 2011; Cui et al., 2016; Rahim et al., 2017; Zhu et al., 2018; Jiang et al., 2019).

A large portion of such low-permeability reservoirs are either in deep-water or more than 5000 m deep onshore (Lehr and Collins, 2014; Kan et al., 2015; EIA, 2016; Yang et al., 2018). The high pressure and high temperature (HPHT) nature of these reservoirs further increase the difficulty in generating a complex and dense fracture network with

* Corresponding author.
** Corresponding author.
E-mail addresses: btliang@cup.edu.cn (T. Liang), jun-lu@utulsa.edu (F. Zhou), zhoufj@cup.edu.cn (J. Lu).

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better coverage. Currently, mechanical diversion and chemical diversion are two main methods to divert the secondary hydraulic fractures to the unstimulated or under-stimulated regions of a reservoir (Grieser et al., 2016; Leonard et al., 2016; Senters et al., 2017). Mechanical diversion has a better chance of creating complete isolations (Leonard et al., 2016); however, it is more expensive and time-consuming (Nasr-El-Din et al., 2007), and may not work reliably in the HPHT reservoirs (Xue et al., 2015; Xiong et al., 2018). Furthermore, mechanical diversion tools need to be drilled after the stimulation, and they can generate debris or remains that blocks the created pathways (Senters et al., 2017). Among various existing chemical diverters, temporary plugging agents have the greatest potential for being used in HPHT reservoirs. Temporary plugging agents are made from degradable polymers, typically polylactic acid (PLA), which can degrade at the reservoir temperature and leave no residue (Van Domelen, 2017). Although it has been claimed that PLA diverters can be used in reservoirs with temperatures up to 150 °C (Fry et al., 2016; Barraza et al., 2017; Senters et al., 2017), all reported field applications with this type of diverters are in reservoirs less than 100 °C, and only used for plugging the perforation holes during the refracturing (Potapenko et al., 2009; Kraemer et al., 2014; Viswanathan et al., 2014; Astafyev et al., 2016; Fry et al., 2016; Leonard et al., 2016; Barraza et al., 2017; Weddle et al., 2017; Senters et al., 2017, 2018); both make the current chemical-diversion applications less valuable as references to the generation of complex fracture networks in low-permeability HPHT reservoirs. Therefore, it is necessary to develop a type of temporary plugging agents that can be used in reservoirs with temperatures above 150 °C, and can achieve both inter-stage diversion (i.e., diverting to under-stimulated perforated zone) and intra-stage diversion (i.e., diverting to new branches within the same perforated zone) during hydraulic fracturing.

In this work, a series of new temporary plugging agents (diverters) are firstly introduced, which can be applied in reservoirs with temperatures up to 200 °C and pressures up to 140 MPa. Then, current experimental methods for evaluating diverters are reviewed, from which a systematic evaluation method is proposed for guiding the usage of different shaped and sized diverters as well as their injection sequence during the stimulation. In the end, field experiments of these diverters in 43 vertical wells in the Tarim Basin (with different diversion designs for comparison) are discussed and analyzed, where reservoir temperatures range from 120 °C to 181 °C. Results indicate that injecting different combinations of fiber-shaped and particle-shaped diverters in different fracturing stages can achieve the inter-stage or intra-stage diversions. Both diversions can expand the fracture network and achieve a better contact with the reservoir, where the intra-stage diversion is more effective on enhancing gas production from the vertical wells. Findings of this paper can provide guidance on efficiently stimulating the low-permeability HPHT reservoirs.

2. Information of target reservoirs and 43 vertical wells

In order to evaluate the effect of diverters on creating a dense and complex fracture network in the HPHT reservoirs, 43 vertical wells are chosen for field experiment in the Keshen gas field in the northern Tarim Basin. The Keshen gas field has a proven reserve of above 5485×10^8 m^3, and vertical wells are used to produce gas due to the average reservoir depth of beyond 6000 m (Lai et al., 2017; Selvadurai et al., 2018). The chosen wells are all located in tight sandstones in the Bashijiqike Formation, with permeabilities ranging from 0.001 to 0.05 mD and porosities ranging from 1.5%–6.5% (Liang et al., 2017; Lai et al., 2017, 2018). Natural fractures are not well developed in the tested reservoirs, whose densities are all less than 0.5 fracture per meter; moreover, they are either cemented or partially cemented by calcite, and cannot serve as flow paths for gas production. Therefore, hydraulic fracturing is needed to create a fracture network to achieve an economical gas production rate. Since the production rate highly relies on the development of the fracture network within a reservoir, production enhancement can be used as a measure of the effect of diversion technique.

Table 1 lists the detailed reservoir information of each well obtained from well-logging, including the depth, the net thickness, the temperature, and the pressure. As shown in the table, the average reservoir thickness is around 100 m, and this brings the first challenge of achieving a uniform reservoir stimulation. For a vertical well, bi-wing fractures are mainly generated from the wellbore, which cannot provide radial coverage on the reservoir without well-developed natural fractures; moreover, vertical heterogeneity in a thick reservoir can also limit fracture initiations from all perforation holes, which reduces the vertical coverage of generated fractures. To overcome this challenge requires that the diversion technique can achieve (1) **intra-stage diversion** where secondary fractures can be generated and branched from the initial bi-wing fracture, and (2) **inter-stage diversion** where secondary fractures can be generated from unstimulated perforation holes. As also shown in this table, the average reservoir temperature is above 150 °C, and this brings the second challenge. This requires that the new diverters (1) have relatively slow degradation rates, and (2) can maintain the plugging strength that allows the secondary fractures to initiate at HPHT.

Table 1
Information of target reservoirs and 43 vertical wells.

Well #	Reservoir Depth (m)	Net Reservoir Thickness (m)	Average Reservoir Temperature (°C)	Average Reservoir Pressure (MPa)
1	6525–6800	218	172	118
2	7209–7244	29	149	124
3	6945–7160	136	165	123
4	5755–5830	42	125	93
5	6747–6840	63	171	122
6	5746–5888	128	140	94
7	5438–5540	99	123	88
8	7140–7180	30	149	118
9	6760–6879	95	121	121
10	6180–6365	113	153	104
11	7487–7577	60	181	126
12	6757–6850	76	123	118
13	7493–7566	42	168	136
14	6853–6965	83	166	109
15	6549–6759	140	167	116
16	5605–5653	119	142	101
17	6767–6880	85	165	122
18	6785–6880	74	169	122
19	6968–7060	59	172	122
20	7710–7780	49	181	126
21	6873–6991	85	146	114
22	7222–7304	107	175	122
23	6805–6930	180	161	114
24	5876–5976	133	130	95
25	5776–5878	123	126	94
26	6840–6926	51	165	117
27	6257–6345	55	145	102
28	5314–5435	125	120	85
29	6593–6710	168	168	116
30	7051–7170	75	165	121
31	7425–7593	86	177	127
32	7445–7552	71	179	128
33	6745–6900	114	157	122
34	7034–7219	189	167	119
35	6520–6702	155	167	117
36	6660–6760	76	161	114
37	6453–6621	83	145	109
38	6406–6578	123	145	108
39	6800–6920	67	169	122
40	6676–6858	117	171	119
41	6746–6897	125	167	123
42	6356–6501	88	145	114
43	6921–7091	104	123	123
Average	6780	98	155	115

3. Laboratory evaluation methods of diverters

To achieve both intra-stage and inter-stage diversions, a series of new diverters have been developed in the lab, whose shapes vary from fibers, particles, to balls with diameters up to 15 mm. Different combinations of them can be applied for plugging the previously formed fractures or the treated perforation holes in different stages of hydraulic fracturing. By changing the copolymers and/or molecular weights of the polymers for making these diverters, their degradation time and plugging strength can be tuned according to the reservoir conditions (Zhou et al., 2018; Zhou et al., 2019). The current diverters synthesized for HPHT reservoirs can maintain the plugging strength at least for 1 h under a maximum temperature of 200 °C and a maximum pressure of 140 MPa (Xue et al., 2015; Xiong et al., 2018). Once degraded, these diverters can be dissolved in the fracturing fluid, without causing any formation damage to the reservoir rock (Zhou et al., 2009; Wang et al., 2015a, 2016a; Liang et al., 2018a). Results also indicate that their degraded solutions are acidic, which may further mitigate formation damage in the near-wellbore region and enhance well injectivity (Wang et al., 2016a; Liang et al., 2017; Liang et al., 2018b).

Modified from the equipment evaluating the lost-circulation materials, stainless-steel slots with various openings were firstly used to study the plugging process and plugging efficiency of the diverters within a fracture (Kefi et al., 2010; Xue et al., 2015; Gomaa et al., 2016a, 2016b). However, the stainless-steel slot cannot provide a direct observation of the formation of plugs within the fracture, nor mimic the rough fracture surface due to its smooth machined surface. Later, a core plug with a split axial fracture was used to mimic a hydraulic fracture and to study the behaviors of diverters therein (Wang et al., 2015a; Du et al., 2017). Although the rough fracture surface was mimicked in this method, a total fracture length of 5–6 cm was not long enough to capture the whole plugging process, and the slot opening could not be adjusted for studying the impacts of fracture width on the plugging efficiency of diverters; moreover, the direct observation was still not conducted to show the plugging process within a fracture.

In our lab, a large-scale transparent slot-flow apparatus is installed, with a length of 4 m, a height of 0.3 m and an adjustable opening of 3–5 mm. It provides an avenue to visualize the flow behaviors of different shaped diverters within a fracture, and more importantly, it helps to identify the key role of fiber-shaped diverters on forming a complete plug within a fracture. As shown in Fig. 1, fibers firstly cling to the edges and rough walls of the fracture, forming numerous "nets" that can capture the flowing particles; then, the isolated islands of fibers and particles gradually join together, and eventually form a complete plug with necessary strength (Yang et al., 2019). To further study the plugging efficiency of diverters at the reservoir conditions, a modified fracture-conductivity evaluation system is developed, in which the rough fracture model is a replica of a fractured rock sample using the 3D scanning and printing technique (Fig. 2). This allows the comparative evaluations of diverters to be conducted on the same fracture model with different initial widths. To mimic the reservoir conditions, two thermocouples are installed to control the system temperature, and one back-pressure regulator is installed to control the system pressure; meanwhile, the rough fracture model is loaded into a testing cell that can set up an initial fracture width, and then the whole cell is loaded into a press machine for generating the closure pressure on fracture (Fig. 3). According to the purposes of experiments, different shapes and/or combinations of diverters are injected into the fracture model until the pressure response showing the formation of a complete plug therein. Then, the whole testing cell is transferred into a CT scanner for observing the location of the plug, as well as the distribution of different shaped diverters without opening the fracture model (Fig. 4). This helps understand the influence of fracture width and its surface morphology on the plugging process when fibers and/or different sized particles are applied in the diversion treatment. Experimental results have indicated that the particle-shaped diverters determine whether a plug can be formed within a fracture, while the fiber-shaped diverters determine the time needed to form a plug and whether a complete plug can form with certain strength. For example, in reservoirs where the tortuous fractures tend to form during the pad injection, small-size particle-shaped diverters are needed to let the plugs to form near tips of the existing fractures; in reservoirs with poor fracability indices (Mullen and Enderlin, 2012; Jin et al., 2015; Alsaif et al., 2017; Yuan et al., 2017), high concentrations of fiber-shaped diverters are needed to form strong plugs for the secondary fractures to initiate.

After the plugging process and plugging efficiency are understood for diverters with different shapes and/or combinations using the single-fracture models, the initiation of secondary fractures after the formation of plugs is further studied using the outcrop blocks with dimensions of 300 mm × 300 mm × 300 mm under the tri-axial stress conditions. To prepare a rock block for such a tri-axial fracturing test, a hole is drilled to the half depth of this sample, where a stainless-steel tubing with perforation holes is installed to mimic a wellbore. After this sample is loaded with the tri-axial stresses, the fracturing fluid is injected through the wellbore to generate fractures within the sample; then, the fracturing fluid with diverters are injected, followed by another round of fracturing fluid injection to generate the secondary fractures. Results from similar studies have shown that refracturing after diversion treatments could either reopen the natural fractures connected with the initial fractures (Wang et al., 2015b; Fu et al., 2018; Mou et al., 2018; Xiong et al., 2018) or initiate secondary fractures from under-stimulated perforation holes on the wellbore (i.e., inter-stage diversion) (Wang et al., 2015a; Mou et al., 2018). However, due to the limitation of sample dimensions, even small diverters screened for inner-fracture plugging from 3D-printed fracture model tests tend to accumulate at perforation holes or openings of the initial fractures. Therefore, although the tri-axial fracturing test might be the largest scaled evaluation method viable in the lab, it is still not large enough to capture the plug formation and fracture initiation from the middle section of a long previously generated fracture (i.e., intra-stage diversion), which is most likely to happen in the field.

To estimate the development of fracture network after diversion treatments in the field scale, a numerical simulator is created based on the extended finite element method using the cohesive zone model

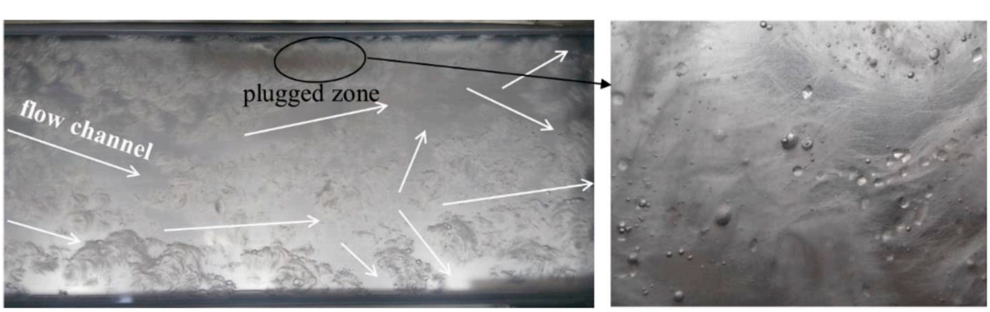

Fig. 1. Plugging process of fiber-shaped and particle-shaped diverters within a large-scale transparent slot-flow apparatus (from Yang et al., 2019).

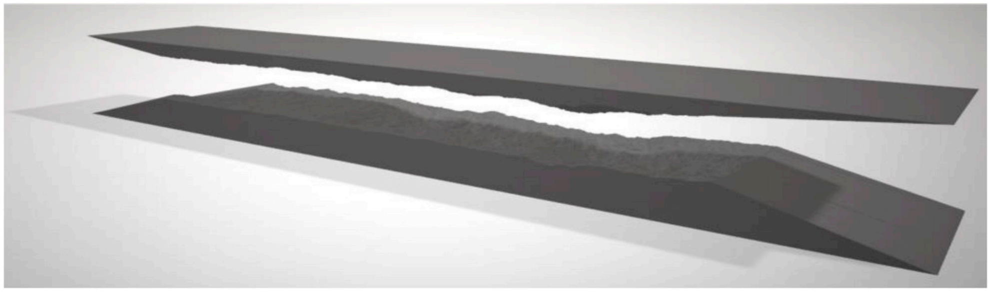

Fig. 2. A rough fracture model duplicated from a fractured rock sample using 3D scanning and printing.

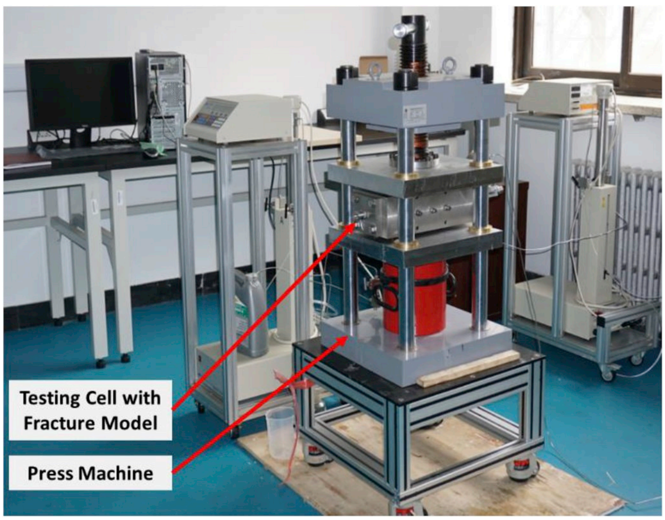

Fig. 3. The press machine for generating the closure pressure upon a fracture model within the testing cell.

(XFEM-based CZM) (Wang et al., 2018a, 2018b). This simulator includes the reservoir heterogeneity, considers the fluid-rock interaction, and allows fractures to propagate along the calculated routes instead of the assigned routes. Simulation is firstly matched with laboratory results of tri-axial fracturing tests using the homogeneous outcrop samples, and then applied to calculate the propagation of secondary fractures in the field scale after initial fractures are plugged. The application includes vertical-well cases where secondary fractures propagate towards new directions from the wellbore (Wang et al., 2019), and horizontal-well cases where secondary fractures propagate from new perforation holes towards the under-stimulated regions (Wang et al., 2018b, 2018c). Diversion treatment can be thus designed combining results from 3D-printed fracture model and simulation; the former optimizes diverter recipes for different reservoir conditions and fractures with different roughness, openings and closure pressures, while the latter optimizes the timing and number of times of diversion treatments and further predicts the coverage of eventual fracture network. Nevertheless, field tests are necessary to verify the diversion designs, compare the effects of intra-stage and inter-stage diversions, and thus establish how to effectively and efficiently conduct diversion treatment in hydraulically fracturing the low-permeability HPHT reservoirs.

4. Field tests of diverters

Field tests are conducted in 43 vertical wells in the Tarim Basin, whose detailed information is listed in Table 1. When hydraulically fracturing these thick and deeply-buried sandstones, proppants are not suggested because of the following reasons. Firstly, proppants settle to the fracture bottom during the slurry injection, which significantly

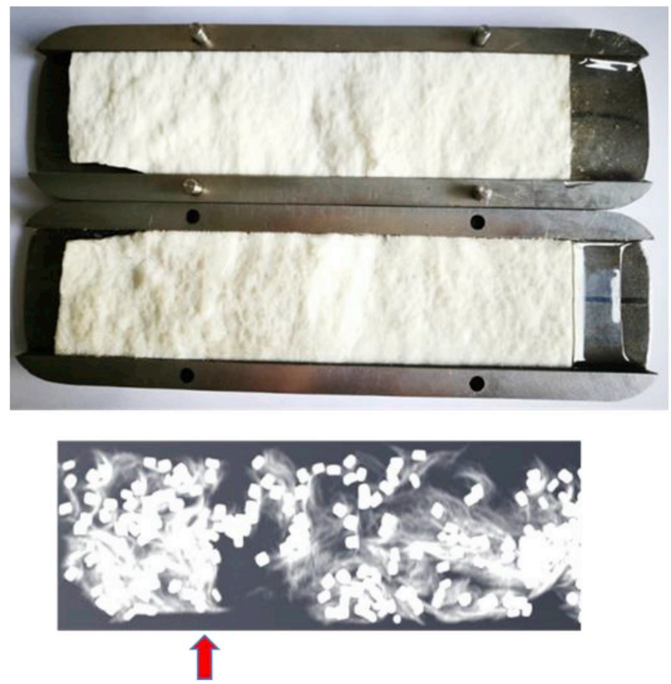

Fig. 4. An open 3D-printed fracture model in the testing cell (top figure), and its CT result obtained after the formation of a complete plug (bottom figure). The CT result shows the location of the plug (pointed by a red arrow), as well as the distribution of fiber-shaped and particle-shaped diverters. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

limits the heights and lengths of the created fractures in the vertical well. Secondly, deeply-buried reservoirs have high pressures that require large hydraulic horsepower for pumping the proppants, which increases the risk of field operation. Thirdly, deeply-buried reservoirs have high temperature and high closure pressure, which accelerates the embedment and crushing of proppants and thus results in the closure of created fractures. Therefore, after the injected pad fluid creates the hydraulic fractures, acid is injected into the reservoir instead of the proppant slurry (i.e., acid fracturing). Acid can etch the reservoir rock and roughen the fracture surface that makes the created fractures still conductive after the closure (Economides et al., 2012). In the tight sandstone reservoirs chosen for testing the diverters, a mixture of hydrofluoric acid (HF) and hydrochloric acid (HCl) is used as the main acid to etch the rock; due to the existence of calcite, an HCl pre-flush is injected before the main acid to remove calcium ions to prevent the precipitation of calcium fluoride. In the end of acid fracturing, a post-flush acid followed by the pad fluid is pumped to replace all the acids within the wellbore for preventing the corrosion. In both the main acid and pre-flush acid, acetic acid is added to reduce the acid-rock reaction rate that allows both acids to travel far along the created fractures. Table 2 lists the detailed recipes of all kinds of fluids used to stimulate the chosen reservoirs.

After the acid fracturing, each well is flowed back and produced for one week to establish a baseline for later comparison. Then, diversion treatments with different evaluation purposes are conducted in 43 vertical wells to compare the effects of intra-stage and inter-stage diversions, as well as the effects of different shaped diverters on both types of diversion treatments. The first six columns of Table 3 list the usage of different shaped diverters in different diversion treatments in these 43 wells, from the single-stage diversion (one intra-stage or inter-stage diversion) to the multi-stage diversion. In each single diversion stage, the diversion treatment is conducted together with the acid fracturing like the baseline, while the usage and pumping schedule of different diverters are designed based on the experimental and simulation results. Detailed field operations with intra-stage and inter-stage diversions are delineated using Well #23 and Well #39 as examples.

Fig. 5 shows the operation curves of Well #23 during the multi-stage diversion treatment, including two intra-stage diversions and one inter-stage diversion as pointed by the black arrows. After this well is stimulated through the acid fracturing and then produced for a week, the pad fluid is pumped again into the wellbore. In the first 32 min, the pumping rate of the pad fluid is kept increasing, and the tubing pressure first increases from the shut-in pressure (about 82 MPa) to the pumping pressure of about 112 MPa and then starts to decrease until the pad fluid fills the wellbore with a volume of 37.5 m^3. After 32 min, the tubing pressure starts to increase again and reaches a plateau at a constant pumping rate of 4.2 m^3/min [redacted]. After 41 min, the pre-flush acid is pumped for 6 min to prevent the potential formation damage, followed by the pumping of the main acid for 6 min to etch the surface of the created fractures. During this period, the tubing pressure keeps decreasing as the typical pressure response during the acid fracturing (Solares et al., 2008; Economides et al., 2012), and this trend may be further exaggerated by the friction reducers added in both acids as shown in Table 2. Meanwhile, at 44 min, 30 kg of particle-shaped diverters with diameters of 1 mm is added in the pre-flush acid and delivered into the fractures for the intra-stage diversion. Then, another round of the pre-flush and main acid are pumped to allow the diverters to reach the previously generated fractures and form complete plugs therein. After pumping one wellbore volume of acids (37.5 m^3), the tubing pressure gradually plateaus (52–53 min) and then increases to a new plateau (53–56 min) for initiating new fractures. The increase of wellhead pressure after this diversion treatment is around 4.3 MPa, which is indicative of a successful diversion from the previously generated fractures (Viswanathan et al., 2014; Barraza et al., 2017; Weddle et al., 2017). After this 1st intra-stage diversion, the pad fluid is pumped again into the wellbore (after 57 min). At the beginning of this second round of the pad fluid fracturing, the pumping rate is kept as low as 1 m^3/min for adding the large-sized particles for plugging the perforation holes with diameters of 8 mm (i.e., inter-stage diversion); at 60 min, 360 particle-shaped diverters with diameters of 6 mm are added in the pad fluid for this inter-stage diversion, along with 25 kg of 1 mm particle-shaped diverters and 10 kg of 3 mm particle-shaped diverters. Once these diverters approach the bottom hole with one wellbore volume of the pad fluid, the pumping rate is raised back to 4.2 m^3/min for better forming complete plugs at the stimulated perforation holes, which is then confirmed by an increase of wellhead pressure of about 9.3 MPa from 69 min to 73 min. After 73 min, the pumping rate is decreased to 2 m^3/min for 4 min and then raised back to 4.2 m^3/min for checking the reliability of the formed plugs. After 81 min, the pumping rate is further raised to 4.7 m^3/min and maintained for 12 min; during this period, the tubing pressure plateaus at about 104 MPa, which is 4 MPa higher than the pressure plateau during the pad fluid fracturing at the first stage (38–43 min). This is indicative of a successful inter-stage diversion, which initiates new fractures in the under-stimulated layers of this thick reservoir. Starting from 94 min, the pre-flush acid and the main acid are pumped alternately as the acid fracturing at the first stage (41–57 min). At 95 min, 30 kg of 1 mm particle-shaped diverters and 50 kg of fiber-shaped diverters are added into the wellbore for the 2nd intra-stage diversion. When the pumping pressure is maintained at 4.2 m^3/min between 101 min and 117 min, the similar pressure response is observed as that during the 1st intra-stage diversion between 46 min and 58 min. The tubing pressure gradually decreases when the acids react with the reservoir rock; once the diverters reach the fractures and gradually form complete plugs therein, the tubing pressure increases until the new fractures start to be generated. The increase of wellhead pressure is around 10.1 MPa after this 2nd intra-stage diversion. After 110 min, when the post-flush acid starts to be pumped into the wellbore, the tubing pressure gradually decreases to a new plateau; this is because the viscosity of the post-flush acid is about half of that of the main acid as shown in Table 2. At the end of the stimulation, the pad fluid is pumped to displace all the acids within the wellbore for preventing the corrosion. Once this well is open again for production, the wellhead pressure increases from 43.5 MPa to 75.5 MPa, and the gas production rate within the first week increases from 108909 m^3/day to 657852 m^3/day. Both indicates a successful reservoir stimulation after the multi-stage diversion treatment.

Fig. 6 shows the operation curves of Well #39 during the multi-stage diversion treatment, including two intra-stage diversions and two inter-stage diversions as pointed by the black arrows. Different from Well #23, the pumping rate of Well #39 is decreased to around 1 m^3/min when adding the diverters for both inter-stage and intra-stage diversion treatments. Due to this frequent change of the pumping rate, the tubing pressure fluctuates more often than that of Well #23. Nevertheless, the pressure responses during the acid fracturing and diversion treatments remain similar as ones observed in stimulating Well #23. After the pad fluid generates the fractures, the pre-flush acid and the main acid are pumped in sequence to roughen the fracture surface, which results in the pressure decrease from 52 min to 61 min. At 62 min, the pumping rate is decreased to 1.2 m^3/min for adding diverters for the 1st intra-stage diversion, where 13 kg of 1 mm particle-shaped diverters and 16 kg of fiber-shaped diverters are used. After one wellbore volume of acids (30.8 m^3) is pumped into the wellbore, an increase of wellhead pressure of 13.7 MPa is observed at 72–74 min, indicating the formation of complete plugs within the previously generated fractures. Later, the pumping rate is decreased to 0.5 m^3/min for adding the large-sized particles for the 1st inter-stage diversion, where 133 particle-shaped diverters with diameters of 8 mm are used with 15 kg of 1 mm particle-shaped diverters and 7 kg of 3 mm particle-shaped diverters (76 min). After another one wellbore volume of fluid is pumped, an increase of wellhead pressure of 18.7 MPa is observed at 93–98 min, indicating the plugging of previously stimulated layers of the reservoir rock. For the 2nd intra-stage diversion, although 18 kg of 1 mm particle-shaped diverters and 24 kg of fiber-shaped diverters are used at 108 min, the increase of wellhead pressure at 118–126 min is likely due to the fluid change within the wellbore instead of the formation of complete plugs

Table 2
Detailed recipes of all kinds of stimulation fluids applied in 43 vertical wells.

Name	Recipe	Viscosity at Surface (mPa·s)
Pad Fluid	0.4 wt% guar + 1 wt% flowback surfactant + 0.1 wt% bactericide + 2 wt% clay stabilizer	40–50
Pre-Flush Acid	9 wt% HCl + 3 wt% acetic acid + 1 wt% flowback surfactant + 2 wt% clay stabilizer + 4.5 wt% corrosion inhibitor + 2 wt% ferric ion sequestering agent + 1 wt% demulsifier + 0.3 wt % friction reducer	20–30
Main Acid	9 wt% HCl + 2 wt% HF + 3 wt% acetic acid + 1 wt% flowback surfactant + 2 wt% clay stabilizer + 2 wt% ferric ion sequestering agent + 1 wt% demulsifier + 0.3 wt% friction reducer	20–30
Post-Flush Acid	1:1 mixture of pad fluid and pre-flush acid	10–15

Table 3
Uses of diverters in different diversion treatments and increases of fracturing pressure after treatments in 43 vertical wells.

Well#	Uses of Diverters in Different Diversion Treatments					Increases of Fracturing Pressure (MPa) after Diversion Treatments				
	1st Intra-Stage Diversion	1st Inter-Stage Diversion	2nd Intra-Stage Diversion	2nd Inter-Stage Diversion	3rd Intra-Stage Diversion	1st Intra-Stage Diversion	1st Inter-Stage Diversion	2nd Intra-Stage Diversion	2nd Inter-Stage Diversion	3rd Intra-Stage Diversion
1	√ (No Fibers)					–				
2	√ (with Fibers)					5.0				
3	√ (with Fibers)					4.2				
4		✓					4.8			
5		✓					4.0			
6		✓					7.1			
7		✓					13.9			
8		✓					8.3			
9		✓					5.4			
10		✓					3.4			
11		✓					11.6			
12		√ (with Fibers)					3.4			
13		√ (with Fibers)					6.8			
14		✓					2.1			
15	√ (with Fibers)	✓				6.4	3.8			
16	√ (with Fibers)	✓				5.9	8.4			
17	√ (with Fibers)	✓				20.6	17.1			
18	√ (with Fibers)	✓				4.2	23.7			
19	√ (with Fibers)	✓				7.4	15.4			
20	√ (with Fibers)	✓				3.1	5.2			
21	√ (No Fibers)	✓	√ (No Fibers)			1.4	12.0	2.1		
22	√ (No Fibers)	✓	√ (No Fibers)			2.9	1.6	–		
23	√ (No Fibers)	✓	√ (with Fibers)			4.3	9.3	10.1		
24	√ (No Fibers)	✓	√ (No Fibers)			1.3	3.6	1.6		
25	√ (with Fibers)	✓	√ (with Fibers)			4.2	9.6	2.1		
26	√ (with Fibers)	✓	√ (with Fibers)			13.4	18.3	9.8		
27	√ (with Fibers)	✓	√ (with Fibers)			5.9	27.3	8.2		
28		✓		✓			2.0		2.3	
29		✓		✓			0.4		1.2	
30		✓		✓			3.2		2.1	
31		✓		✓			6.9		8.6	
32		✓		✓			2.0		4.9	
33	√ (No Fibers)	✓	√ (No Fibers)	✓		4.2	10.6	1.9	3.9	
34	√ (No Fibers)	✓	√ (No Fibers)	✓		–	12.6	–	12.8	
35	√ (No Fibers)	✓	√ (No Fibers)	✓		1.5	9.7	–	5.4	
36	√ (with Fibers)	✓	√ (with Fibers)	✓		–	9.6	2.7	9.6	
37	√ (with Fibers)	✓	√ (with Fibers)	✓		6.3	8.8	2.1	9.3	
38	√ (with Fibers)	✓	√ (with Fibers)	✓		3.2	7.2	2.6	5.3	
39	√ (with Fibers)	✓	√ (with Fibers)	✓		13.7	18.7	–	5.6	
40		✓	√ (No Fibers)	✓	√ (No Fibers)		4.2	–	7.3	3.2
41		✓	√ (No Fibers)	✓	√ (No Fibers)		2.8	–	2.9	–
42	√ (with Fibers)	✓		✓	√ (with Fibers)	4.4	7.3		3.0	2.7
43	√ (No Fibers)	✓	√ (No Fibers)	✓	√ (No Fibers)	–	14.8	–	12.6	–

Notes: 1. "√" means diverters were applied either for intra-stage diversion or inter-stage diversion.
2. For the inter-stage diversion, only particle-shaped diverters were applied for plugging perforation holes unless otherwise noted.
3. "–" means the increase of fracturing pressure was negligible (<1 MPa) after the diversion treatment.

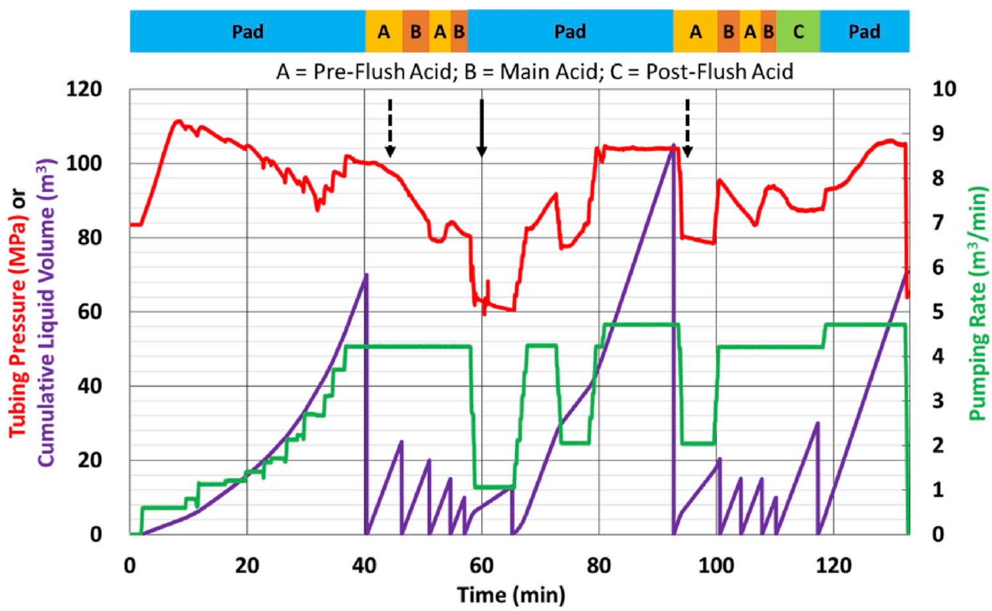

Fig. 5. Operation curves of Well #23 during the multi-stage diversion, including changes of the tubing pressure (red curve), the cumulative liquid volume (purple curve) and the pumping rate (green curve). Two black dotted arrows point the moments of applying the diverters for the intra-stage diversions (44 min and 95 min), while one black solid arrow points the moment of applying the diverters for the inter-stage diversion (60 min). (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

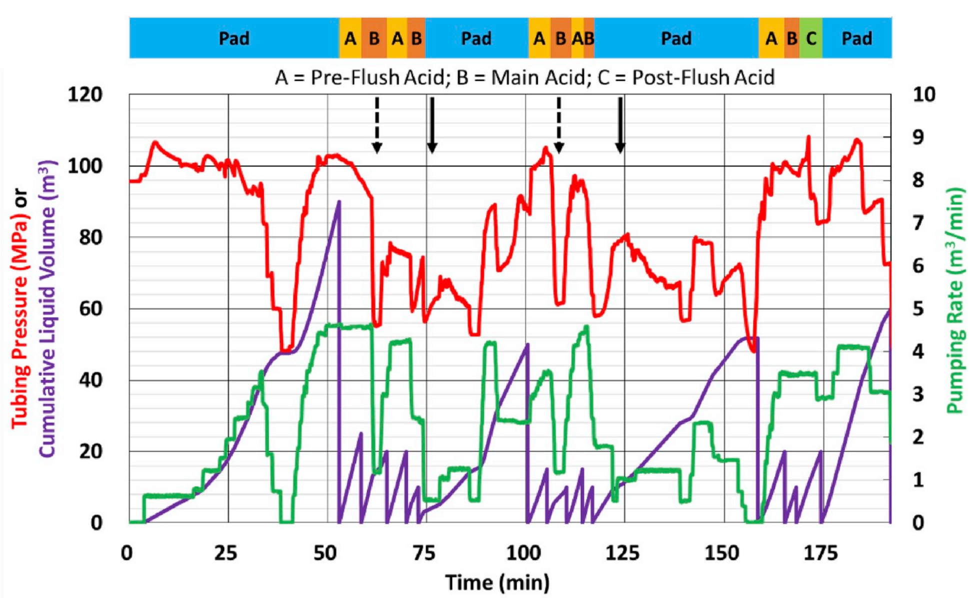

Fig. 6. Operation curves of Well #39 during the multi-stage diversion, including changes of the tubing pressure (red curve), the cumulative liquid volume (purple curve) and the pumping rate (green curve). Two black dotted arrows point the moments of applying the diverters for the intra-stage diversions (62 min and 108 min), while two black solid arrows point the moments of applying the diverters for the inter-stage diversions (76 min and 124 min). (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

within the previously generated fractures; comparing to the acids pumped ahead, the pad fluid pumped after 117 min is more viscous and does not contain friction reducers, both of which can disguise the signal of forming the complete plugs. For the 2nd inter-stage diversion, large-sized particles are used at 124 min, which generates an increase of wellhead pressure of 5.6 MPa at 149–154 min. After this multi-stage diversion treatment, the wellhead pressure increases from 74.2 MPa to 91.8 MPa, and the gas production rate within the first week increases from 180369 m^3/day to 971244 m^3/day.

Table 3 summarizes the usage of different shaped diverters as well as the increase of wellhead pressure in each single diversion treatment of all 43 vertical wells conducted in this study. Table 4 summarizes the enhancements of wellhead pressure and gas production rate before and after different diversion treatments listed in Table 3. Comparing these two tables helps understanding the difference of the intra-stage diversion and the inter-stage diversion, as well as the effects of different shaped diverters in both types of diversions, none of which is attainable from the current laboratory evaluation or simulation methods.

4.1. Comparison on effect between intra-stage diversion and inter-stage diversion

As discussed in the introduction, all the field tests on diverters by far aim to plug the perforation holes where hydraulic fractures have already been initiated, and thus to divert the following fracturing fluid to the under-stimulated perforation holes in the neighboring stages. This kind

Table 4
Enhancements of wellhead pressure and gas production rate after diversion treatments in 43 vertical wells.

Well#	Before Diversion Treatment		After Diversion Treatment		Enhancements after Diversions	
	Wellhead Pressure (MPa)	Gas Production Rate (m^3/day)	Wellhead Pressure (MPa)	Gas Production Rate (m^3/day)	Increase of Wellhead Pressure	Increase of Production Rate
1	73.8	357448	73.9	722127	0.18%	102.02%
2	61.2	204300	76.8	1161500	25.47%	468.53%
3	49.2	163190	86.1	431559	74.97%	164.45%
4	65.4	250151	68.2	799637	4.30%	219.66%
5	/	/	53.4	230351		
6	56.8	201168	68.7	855265	20.89%	325.15%
7	32.5	59164	65.7	252158	102.15%	326.20%
8	34.9	46363	66.5	167116	90.69%	260.45%
9	32.1	30693	38.4	106557	19.63%	247.17%
10	/	/	34.3	215256		
11	83.6	190686	93.8	848720	12.20%	345.09%
12	43.4	64767	61.2	214521	41.01%	231.22%
13	/	/	52.1	202112		
14	76.5	93074	77.4	154870	1.11%	66.39%
15	70.2	142417	74.0	585084	5.34%	310.82%
16	42.5	169038	72.5	910288	70.44%	438.51%
17	84.8	245073	91.4	870780	7.80%	255.31%
18	79.2	144336	89.5	1002726	12.97%	594.72%
19	91.7	154769	92.3	650526	0.65%	320.32%
20	61.2	119640	76.3	221502	24.67%	85.14%
21	/	/	64.8	232364		
22	27.1	61615	97.2	474861	258.67%	670.69%
23	43.5	108909	75.3	657852	73.18%	504.04%
24	16.1	32616	59.8	319302	271.27%	878.97%
25	47.2	69324	65.1	436980	37.86%	530.34%
26	/	/	39.6	156057		
27	/	/	80.6	703272		
28	51.6	131798	66.5	347872	28.78%	163.94%
29	83.7	641455	87.6	853240	4.66%	33.02%
30	72.4	167648	86.8	1015332	19.93%	505.63%
31	58.5	199301	92.3	966384	57.78%	384.89%
32	78.5	406695	96.1	1134714	22.39%	179.01%
33	90.5	323804	95.9	1199580	6.00%	270.46%
34	/	/	27.9	6740		
35	54.6	127056	75.3	449520	37.91%	253.80%
36	60.6	134769	78.1	1032000	28.79%	665.75%
37	78.9	178185	84.0	851812	6.46%	378.05%
38	29.1	26704	47.7	121308	64.05%	354.27%
39	74.2	180369	91.8	971244	23.72%	438.48%
40	44.6	206070	79.8	683531	78.93%	231.70%
41	90.5	287642	91.2	1136040	0.79%	294.95%
42	35.7	57893	38.8	260445	8.68%	349.87%
43	46.3	49272	53.5	162504	15.57%	229.81%

of diversion is relatively easy to conduct in the field and named “inter-stage diversion” in this study. However, generating a complex and dense fracture network within a given fracturing stage is more dependent on plugging middle sections of existing fractures and initiating secondary fractures between each plug and the wellbore, which allows the fracture network to branch out towards the unstimulated reservoir; this is named “intra-stage diversion” in this study. As shown in Table 3, among the chosen 43 vertical wells, 3 wells are stimulated with one intra-stage diversion (Wells #1—#3), 11 wells are stimulated with one inter-stage diversion (Wells #4—#14), 5 wells are stimulated with two inter-stage diversions (Wells #28—#32), 6 wells are stimulated with one intra-stage diversion and one inter-stage diversion (Wells #15—#20), 7 wells are stimulated with two intra-stage diversions and one inter-stage diversion (Wells #21—#27), and 9 wells are stimulated with two intra-stage diversions and two inter-stage diversions (Wells #33—#42). Comparison of the production enhancements after these six types of diversion treatments shows that the intra-stage diversion is more effective on increasing the contact area of the fracture network with the reservoir, which are detailed below.

As shown in Table 4, for wells stimulated with only one intra-stage diversion (Wells #1—#3), the averaged production enhancement is around 245%; this production enhancement is similar as the ones stimulated with only one inter-stage diversion (Wells #4—#14), which is around 253%. Both diversions can initiate secondary fractures and expose more reservoir rock, and one single-stage diversion is not enough to show their difference within these thick reservoirs. Then, the multi-stage diversions are conducted. For wells with two inter-stage diversions (Wells #28—#32), the average production enhancement remains at around 253%. However, when one intra-stage diversion and one inter-stage diversion are conducted (Wells #15—#20), the average production enhancement increases to around 334%; furthermore, when one more intra-stage diversion is conducted (Wells #21—#27), the average production enhancement increases to around 646%, excluding 3 previously unproductive wells obtain stable gas production rates of above 150,000 m^3/day. However, for wells stimulated after two or three intra-stage diversions and two inter-stage diversions (Wells #33—#43), although significant increases of the wellhead pressures are still observed, the average production enhancement is only 347%. One important reason is because the fiber-shaped diverters are not used in several wells during their intra-stage diversions, which limited the initiation of secondary fractures, and thus their production enhancements. This will be delineated in Section 4.2.

Nevertheless, although the intra-stage diversion is more effective on initiating the secondary fractures, it is conducted when pumping the pre-flush acid or the main acid, and the designed amounts of acid usage can limit the time allowing the secondary fractures to initiate and propagate. Therefore, further studies are needed to improve the intra-stage diversion design, which may generate highly branched fractures with an economical fluid (the pad fluid and acids) usage.

4.2. Fiber-shaped diverters in intra-stage diversion

As introduced above, laboratory evaluations have shown that the fiber-shaped diverters can help the formation of complete plugs within the previously generated fractures (Yang et al., 2019; Yuan et al., Submitted). This is confirmed by the field tests in this study. For wells whose intra-stage diversions are conducted with the fiber-shaped diverters, increases of wellhead pressure during fracturing are more significant as shown in Table 3. One example is Well #23, where the fiber-shaped diverters are used in its 2nd intra-stage diversion but not in its 1st intra-stage diversion. As shown in Fig. 5, although the stimulation is maintained similar in both intra-stage diversions, increase of wellhead pressure in the 2nd intra-stage diversion is 10.1 MPa while that in the 1st intra-stage diversion is only 4.3 MPa. Furthermore, for 25 wells started with the 1st intra-stage diversion, the fiber-shaped diverters generate an average increase of wellhead pressure of 6.7 MPa (Wells #2, #3, #15—#20, #25—#27, #36—#39 and #42), which is 5 MPa higher than that of wells stimulated with only the particle-shaped diverters (Wells #1, #21—#24, #33—#35 and #43). Once complete plugs are formed that prevent the fracturing fluid flowing towards the tips of previously generated fractures, wellhead pressure increases until the secondary fractures initiate from locations where fracture-initiation pressures are smaller than the achieved increase of net pressure within the plugged fractures. Therefore, the faster and stronger the complete plugs are formed, the more the secondary fractures can branch off from the initial fractures, and thus the better the stimulation can be achieved. This is not obvious when comparing the wells whose initial stimulation does not generate an economical production rate, since any diversion can result in a significant enhancement (Wells #25—#27 vs. Wells #21, #22 and #24). However, this is clearly observed when comparing the wells whose initial production rates are already higher than 100,000 m^3/day, where production enhancements are closely related to the applied diversion treatments. For wells treated with the fiber-shaped diverters, the average increase of wellhead pressure is 4.1 MPa in each intra-stage diversion, and the average production enhancement is 494% after the whole treatment (Wells #36, #37 and #39); both are significantly higher than those of the wells treated only with the particle-shaped diverters, which are 1.4 MPa and 263% respectively (Wells #33, #35, #40 and #41).

Nevertheless, to further confirm the hypothesis requires more straightforward observation methods, which can be far more expensive. These methods include using the Distributed Acoustic Sensor (DAS) and the Distributed Temperature Sensor (DTS) to observe the formation of initial and secondary fractures before and after diversions (Haustveit et al., 2017; Somanchi et al., 2018), using radioactive tracers to differentiate the production enhancement after each diversion treatment (Viswanathan et al., 2014; Weddle et al., 2017; Senters et al., 2018), or even drilling a core along the fractured well to obtain its fracture distribution (Raterman et al., 2017; Ciezobka et al., 2018; Shrivastava et al., 2018).

4.3. Fiber-shaped diverters in inter-stage diversion

Comparing to the intra-stage diversion, the inter-stage diversion is relatively easy to conduct in the field, and its successful applications have been widely reported as mentioned in the introduction. To accomplish the inter-stage diversion, particle-shaped diverters are currently used to plug the perforation holes where hydraulic fractures have been generated. Laboratory evaluation results have shown that particle-shaped diverters with different diameters can plug the perforation holes by themselves; however, compared with cases using both fiber-shaped and particle-shaped diverters, the time needed to form a complete plug is delayed and the strength of the formed plug is weaker (Yang et al., 2019). But so far, no published work has shown the effect of fiber-shaped diverters in the inter-stage diversion in the field.

In field experiments of this study, among 11 wells stimulated with one inter-stage diversion, 2 wells use the combination of fiber-shaped diverters and particle-shape diverters (Wells #12 and #13) while the other 9 wells use only the particle-shaped diverters (Wells #4—#11 and #14). From operation curves of Wells #12 and #13, no obvious change of the pressure response time is noted when fiber-shaped diverters are used in the inter-stage diversion; increases of wellhead pressure are observed after one wellbore volume of fracturing fluid is pumped following the diverters, as ones observed in operation curves of Wells #23 and #39 (Figs. 5 and 6). Furthermore, as shown in Tables 3 and 4, no significant difference is observed in the increase of wellhead pressure or the production enhancement after fiber-shaped diverters are used with particle-shaped diverters during the inter-stage diversion. Therefore, it can be confirmed that although the fiber-shaped diverters are important in the intra-stage diversion treatment, they are not necessary to plugging perforation holes in the inter-stage diversion treatment in a vertical well.

5. Conclusions

Efficiently producing gas from low-permeability reservoirs relies on generating complex and dense fracture network. However, HPHT reservoirs have temperatures of above 150 °C, which limits the application of conventional stimulation methods. A series of new diverters have been developed, which can be applied to hydraulic fracturing the reservoirs with temperatures up to 200 °C and pressures up to 140 MPa. After the stimulation, diverters can degrade at the reservoir condition, leaving no residue that causes the formation damage.

In the lab, the plugging process and plugging efficiency of these diverters are first evaluated using a single-fracture model with 3D printed fracture surfaces, from which the combination of different shaped and sized diverters can be optimized for fractures with different openings and tortuosities. Then, the initiation of secondary fractures after the formation of plugs is evaluated using outcrop blocks with dimensions of 300 mm × 300 mm × 300 mm under tri-axial stress conditions. Results show that the natural fractures can be reopened, and the secondary fractures can be initiated from the under-stimulated perforation holes once the complete plugs are formed in the blocks. However, this tri-axial fracturing test is still not large enough to capture the plug formation and fracture initiation in the middle section of the previously generated fractures, and thus unable to evaluate the intra-stage diversion that is more crucial to the stimulation of low-permeability gas reservoirs.

Based on the experimental results, a numerical simulator is created using XFEM-based CZM, which can predict the fracture propagation before and after the diversion treatment and thus help optimize the field operation designs of intra-stage and inter-stage diversions. Then, 43 vertical wells in an HPHT reservoir are chosen to examine different diversion designs, and, more importantly, to understand effects of the intra-stage diversion as well as the fiber-shaped diverters in both types of diversions. Findings and learnings from these field experiments are listed as follows.

(1) The intra-stage diversion can enhance the radial coverage of the generated fracture network, and thus more effective in production enhancement than the inter-stage diversion in vertical wells. Similarly, intra-stage diversion can be also effective in stimulating horizontal wells with large ratios between two horizontal stresses, where secondary fractures can branch off from main fractures and reduce gaps among fractures.
(2) In the intra-stage diversion, fiber-shaped diverters can enhance the formation of complete plugs in the previously generated fractures, thus enhancing the increase of net pressure within

these plugged fractures and allowing more secondary fractures to be generated between the formed plugs and perforation holes.

(3) In the inter-stage diversion, which has already been successfully conducted in the field, particle-shaped diverters can plug the perforation holes by themselves and no fiber-shaped diverters might be needed to simplify the operation and reduce the cost.

Declaration of competing interest

The authors declare that they have no conflict of interests.

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Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.petrol.2019.106738.

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