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A novel stimulation strategy for developing tight fractured gas reservoir☆

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Conventional stimulation methods such as matrix acidizing, acid fracturing, or proppant fracturing have resulted in products that perform poorly and/or fail within months. Other options, such as water fracs with light sand, give better results but are prohibitively expensive. Mineral composition, brittleness index, stress regime, and petrophysical properties, which are favorable for creating complex fracture networks, can be obtained by geochemical and geomechanical analysis. The extended Reshaw and Pollard criterion shows that hydraulic fractures tend to be arrested by pre-existing natural fractures, and complex fracture networks would be created during fracturing. Additionally, the critical stressed faults theory indicates that the pre-existing natural fractures tend to slip with the shear mode as the pore fluid pressure increases. Rotating disk experiments and conductivity tests with artificial sheared plates have shown that flow channels can be etched at the location of scratches on fracture surfaces. Meanwhile, the carbonate cement in natural fractures can be chelated to form wormhole likely flow channels. Complex fracture networks with sufficient acid etched conductivity can be generated by water fracs with acid. A novel and economical volume stimulation strategy known as network acid fracturing has provided Tarim Oil Company the means to develope ultra-deep, ultra-high pressure, high temperature, and ultralow permeability but fractured gas reservoirs. Post-stimulation production performances of numerous wells with network acid fracturing are comparable to those with stimulated reservoir volumes.

1. Introduction

The great success of Barnett shale triggered the shale gas revolution in North America. Fisher et al. [1], Maxwell et al. [2], and Fisher et al. [3] were the first researchers to discuss the creation of fracture networks in Barnett shale. Their work gave rise to the basic principles of Stimulated Reservoir Volume (SRV). The generation of complex fracture networks with SRV has been being the key technology for the development of unconventional resources, such as tight gas, tight oil, shale gas and ultralow permeability reservoirs [4]. Pre-existed natural fractures [5], formation rock brittleness [6], stress anisotropy, and interfacial friction [7] are the most important factors in creating network fractures. Gu and Weng [8] quantitatively analyzed the influence of stress anisotropy and intersection angles on crossings in order to interpret the creation of complex fracture networks with the extended Reshaw and Pollard criterion [9]. Olson and Dahi-Taleghani [10] and, later, Dahi-Taleghani and Olson [11] detailed the influence of hydraulic fracture on debonding or shearing of cemented natural fractures. Hydraulic fracture is arrested by and propagated along dilated natural fractures and/or multiple fracture fronts propagations while crossing will form complex fracture networks. Slick-water is most commonly used in SRV to connect hydraulic fractures and pre-existing natural fractures to form complex fracture network, and a small amount of proppant with a low sand ratio is mostly used to prop fracture networks [12]. Hydrochloric acid was utilized to ensure fracture

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initiation in Eagle Ford shale via dissolving acid-soluble cement and alleviating all perforation and near-wellbore friction [13]. Li and Dai [14] analyzes the feasibility by the comparison of reservoir characteristics of shale gas with tight-gas carbonate, meanwhile, analyzes the validity and limitation of the volume acid fracturing technology and gives the solution for the limitation. However, there has been no research on whether acid can be used in SRV to obtain network fracture conductivity for tight but fractured sandstone reservoirs in which most of the pre-existing natural fractures have been cemented by carbonate.

The targeted Cretaceous tight sandstone of the Kuqa gas reservoir in the northwest Tarim Basin is 5300–7000 m buried, and characterized by low porosity (about 7%) and ultralow permeability (about $0.07 \times 10^{-3} \mu m^2$ for matrix porous). However, it is well developed with pre-existing natural fractures, while almost all of these natural fractures have been cemented by carbonate. Conventional stimulation strategies, such as matrix acidizing, acid fracturing and proppant fracturing, had been practiced. However, the results have been disappointing. The introduction of fiber assisted re-orientation SRV with propped fracture networks performed well, but proved very costly [15,16]. Microseismic fracture mapping of SRV pilot tests in the Kuqa gas reservoir has shown that slick-water can stimulate natural fractures adequately to form complex network fractures. Acid can be used to dissolve carbonate cement and etch fracture surfaces selectively. It can also provide adequate network fracture conductivity in such ultralow permeability reservoirs. Therefore, multistage network acid fracturing with diversion between stages and temporary plugging within fractures can be considered as an alternative stimulation strategy for fiber assisted re-orientation SRV. Dozens of wells have been implemented with such technology by PetroChina Tarim Oil Company, and their production performances have been comparable to fiber assisted re-orientation SRV.

2. Generation of complex fracture networks

Research into hydraulic fracturing in shale gas has indicated that mineral components, brittleness, natural fractures, stress regime, horizontal stress anisotropy, and intersection angles between hydraulic fracture and pre-existing natural fractures play key roles in creating complex fracture networks. The geochemical and geomechanical properties of Kuqa tight sandstone were investigated to show whether complex fracture networks can be created during hydraulic fracturing.

2.1. Geochemical and geomechanical considerations

X-ray diffraction analysis showed that the quartz group (including quartz, feldspars, and pyrites), the carbonate group (including calcite, dolomite, and siderite), and the clay group (including total clays) of rock samples from six wells ranged from 70.33 wt% to 95.45 wt%, 1.64 wt% to 16.87 wt%, and 2.3 wt% to 21.77 wt%, respectively. The BI (Brittleness Index) of Kuqa tight sandstone was about 83.4 from the mineralogy view [17]. Alternatively, it was about 54.8 when calculated with Young's modulus and Poisson's ratio interpreted from well logging datum [18].

Pre-existing natural fractures were analyzed in 13 cores drilled from K2 well blocks. The total length of the cores was 447.07 m, and they covered the whole targeted intervals. Fracture dimensions and mineral fill were recorded for each individual fracture, and fracture pattern characteristics were also noted. Fracture orientation data was collected with a Fullbore Microscan Imager (FMI) for Water base Mud (WBM), and with an Earth Image (EI) for Oil Base Mud (OBM). Fig. 1 shows the FMI logging and core observations of well K2-14. Based on the appearance of natural fractures in the high-resolution electrical images, the pre-existing natural fractures were interpreted and classified as conductive, resistive, critically stressed, fault, and drilling enhanced. The classification indicates the relative strength of the natural fractures. The resistive fractures were closed and mineralized, while active faults and critically stressed fractures were more open and conductive, even under the original in-situ stress state. These fractures can be stimulated easily during hydraulic fracturing. Almost all of the natural fractures in this core were cemented with carbonate (Fig. 1b). Most of the observed fractures from these 13 cores were sub-vertical, with dip angles range predominantly between 60° and 90° (Fig. 2a). Fracture azimuth could be observed to have two distinct trends, heterotropic to one another. Statistical analysis on the fracture azimuth data revealed a bimodal normal distribution, with modes being approximately 120° and 330° (Fig. 2b).

Vertical stress was calculated by integrating formation density, which is obtained from wireline logs. The orientation and magnitude of the horizontal principal stresses was determined from wellbore breakouts [19]. The averaged vertical stress, maximum horizontal stress, minimum horizontal stress, and stress anisotropy (defined as the difference between maximum and minimum horizontal stresses) were 142 MPa, 176 MPa, 164 MPa, and 34 MPa, respectively. The relative magnitude of the three principal stresses indicates the stress regime to be strike slip faulting.

2.2. Probability of generation complex fracture networks

A comparison of the geochemical and geomechanical properties of typical shale gas and Kuqa tight sandstone is shown in Table 1. The brittleness index, stress regime, petrophysical properties, and pre-existing natural fractures of Kuqa tight sandstone are favorable for the creation of complex fracture networks during hydraulic fracturing. However, the relatively high stress anisotropy makes formation of complex fracture networks more difficult than in shale gas.

The extended Renshaw and Pollard criterion proposed by Gu and Weng [8] was used to investigate the interaction behaviors between pre-existing vertical natural fractures and hydraulic fractures under given in-situ horizontal stresses and interfacial properties. The results indicated that hydraulic fractures tended to be arrested by natural fractures where intersection angles $\beta < 60°$, coefficient of friction $\mu_f = 0.6$, and in-situ horizontal stress ratio 1.14 $\le \sigma_H/\sigma_h \le$ 1.32. The shear (τ) and normal (σ_n), stresses on any three dimensional fracture can be determined by its strike and dip angle. When the Coulomb Failure Function, $CFF = \tau - \mu_f \sigma_n$, becomes positive with an increase of pore pressure, P_p, during hydraulic fracturing, the originally stable fractures would be activated in shear mode. The critically stressed faults theory proposed by Barton and Zoback [26] was employed to calculate the pore fluid pressure needed to slip natural fractures with arbitrary dip and strike angles [27]. The results showed that the pre-existing natural fractures cannot slip under averaged original stress states ($\sigma_{hmin} = 142$ MPa, $\sigma_{Hmax} = 176$ MPa, $\sigma_v = 164$ MPa), but started to dilate in shear mode when pore fluid pressure, P_p, increased from 120 MPa up to 126 MPa, and most of the fractures dilated for $P_p = 135$ MPa. The strike-slip faulting stress regime, geochemical properties, and mineral and natural fracture orientation distribution of Kuqa tight sand reservoir demonstrated that complex fracture networks would be created during hydraulic fracturing.

This paper integrates the shear slippage criterion with closed natural fractures proposed by Warpinski and Teufel [28], the crossing criterion proposed by Blanton [29], and the re-initiation criterion at the natural fracture tip in order to investigate the complicated intersection behaviors and required conditions.

The shear slippage criterion for vertical natural fracture was