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A New Fracturing Method to Improve Stimulation Effect of Marl Tight Oil Reservoir in Sichuan Basin

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Abstract: China's argillaceous limestone reservoir has a lot of oil and gas resources, and hydraulic fracturing of the argillaceous limestone reservoir faces many difficulties. The first problem is that the heterogeneity of the argillaceous limestone reservoir is strong, and it is difficult to optimize fracturing parameters. The second problem is that there are a lot of natural fractures in the argillaceous limestone reservoir, which leads to a lot of fracturing fluid loss. The third problem is that the closure pressure of the argillaceous limestone reservoir is high, and the conductivity of fractures decreases rapidly under high closure pressure. The last problem is that the fracture shape of the argillaceous limestone reservoir is complex, and the law of proppant migration is unclear. The main research methods in this paper include reservoir numerical simulation, fluid-loss-reducer performance evaluation, flow conductivity tests and proppant migration visualization. To solve the above problems, this paper establishes the fracturing productivity prediction model of complex lithology reservoirs and defines the optimal hydraulic fracturing parameters of the argillous limestone reservoir in the Sichuan Basin. The 70/140 mesh ceramide was selected as the fluid loss additive after an evaluation of the sealing properties of different mesh ceramides. At the same time, the hydraulic fracture conductivity test is carried out in this paper, and it is confirmed that the fracture conductivity of 70/140 mesh and 40/70 mesh composite particle-size ceramics mixed according to the mass ratio of 5:5 is the highest. When the closure pressure is 40 MPa, the conductivity of a mixture of 70/140 mesh ceramic and 40/70 mesh ceramic is 35.6% higher than that of a mixture of 70/140 mesh ceramic and 30/50 mesh ceramic. The proppant migration visualization device is used to evaluate the morphology of the sand dike formed by the ceramsite, and it is clear that the shape of the sand dike is the best when the mass ratio of 70/140 mesh ceramsite and 40/70 mesh ceramsite is 6:4. The research results achieved a good stimulation effect in the SC1 well. The daily oil production of the SC1 well is 20 t, and the monitoring results of the wide-area electromagnetic method show that the fracturing fracture length of the SC1 well is up to 129 m.

Keywords: argillaceous limestone; hydraulic fracturing; numerical simulation; proppant; migration law; tight oil

Citation: Wang, Y.; Fan, Y.; Li, S.; Lv, Z.; He, R.; Wang, L. A New Fracturing Method to Improve Stimulation Effect of Marl Tight Oil Reservoir in Sichuan Basin. *Processes* **2023**, *11*, 3234. https://doi.org/10.3390/pr11113234

Academic Editors: Keliu Wu, Mingjun Chen and Jiajia Bai

Received: 25 July 2023
Revised: 8 September 2023
Accepted: 10 September 2023
Published: 16 November 2023

1. Introduction

With the development of the global economy and society, the demand for oil and gas resources in various industries is increasing day by day [1–3]. At present, conventional oil and gas resources are becoming increasingly scarce, and the importance of unconventional oil and gas resources in the energy supply is becoming increasingly apparent. China has mastered the key theory and technology of shale gas development, but there are still a lot of technical problems to be solved in the field of tight oil [4–6]. The burial depth of reservoirs of tight oil in China ranges from 1800 m to 4950 m. The Jimusar Basin has a burial depth ranging from 2300 m to 4200 m, the Ordos Basin has a burial depth ranging from 1800 m to 2500 m, and the Shulu Depression Basin has a burial depth ranging from 3700 m to 4950 m. These deep reservoirs pose challenges for the exploration and production of tight oil [7].

Tight oil reservoirs are primarily characterized by low porosity, low permeability, complex lithology, and a multitude of natural fractures in the reservoir [8–10]. The main challenges of tight oil fracturing are as follows: ① The reservoir lithology is complex, alternating between limestone and mudstone layers. Mudstone can inhibit fluid seepage, which in turn affects the spread of fracturing waves, making it more difficult to achieve effective fracturing; ② furthermore, the reservoir contains a large number of natural fractures, which can complicate filtration of the fracturing fluid, resulting in less effective fracturing [11]; ③ and tight oil reservoirs are very dense, with low porosity and permeability, and fracturing has high requirements for fracture length and conductivity [12].

In order to expand the drainage radius of tight oil reservoirs, volume stimulation is often used for tight oil fracturing. Shicheng Zhang et al. [13] used a combination of finite element and discrete element methods to establish a model with which to describe hydraulic fracture propagation in tight oil reservoirs. Simulations have shown that the formation of complex crack network systems is favored when the level stress difference is less than 5 MPa; if the horizontal stress difference is greater than 6 MPa, a planar crack system can easily form; the effectiveness of volumetric fracturing may improve as the injection rate increases; and the density of natural cracks may only have a significant effect on the bulk excitation effect at low stress differences. Through laboratory modeling experiments and on-site application results evaluation, Fujian Zhou et al. [14] proposed a set of fracturing and enhanced oil recovery technologies suitable for China's tight oil development, mainly consisting of temporary plugging, micro-sized proppants, and nano-fracturing fluids. Xu Jiangwen et al. [15] integrated a series of volume-fracturing technologies after 5 years of exploration based on the concept of "fracture controlled reserves". Hai Liu et al. [16] applied a unique unconventional fracture model (UFM) to design and evaluate hydraulic fracturing treatments for unconventional reservoirs. This model combines a predefined natural fracture pattern with hydraulic and natural fracture interaction criteria. Jin Chengzhi et al. [17] developed stimulation design techniques to optimize fracture spacing, fracture section division, perforation, fracture length and height, as well as fracture conductivity in heterogeneous tight oil reservoirs located in the Songliao Basin. Based on the data of rock mechanics parameters, crustal stress characteristics, brittleness characteristics and natural fractures, Huan Zhao et al. [18] analyzed the influencing factors of SRV fracturing in tight reservoirs. The results indicate that SRV fracturing is suitable for geological reservoirs that have a moderate to high elastic modulus, a moderate to low Poisson ratio, low stress differences, moderate to high elasticity, and natural fracture properties, where natural fractures have a significant effect. Based on the mechanism of oil recovery through imbibition, Wang Ce et al. [19] innovatively proposed the large-scale volume fracturing of horizontal wells and established a new development model of production with pressure maintenance, integrating comprehensive energy supplies, closure of existing fractures, synchronous transformation, and volume fracturing for the first time. This new model surpassed the traditional water drive characteristics and has been successfully applied to the Yuan284 block of ultra-low permeability reservoirs in the Huaqing oilfield. The simulation of tight oil reservoir productivity is crucial for optimizing fracturing design. In their study, Bazan et al. [20] investigated the impact of fracture parameters and interference on fracture geometries and well production, while Armin Shirbazo et al. [21] focused on the influence of hydraulic fracture parameters on horizontal well productivity, emphasizing the significant role of fracture stages and conductivity in production improvement. Increasing the number of fracture stages and conductivity can help increase production, but the number of fracture stages and the conductivity cannot be increased indefinitely, and there is an optimal value for both. Deng et al. [22] presented a new automatic integrated optimization algorithm with NPV as the objective function. Simulation results showed that the optimal fracture placement is a spindle-like placement, which has a much higher NPV than the uniform fracture placement. Aleksandra Peshcherenko et al. [23] built a hydraulic fracture development model to determine the best characteristics for fracture placement. Omar Al-Fatlawi et al. [24] established an equivalent simplified homogeneous reservoir simulation model to optimize the number and half-length of the fractures with net present value (NPV) as the objective function. Daobing Wang et al. [25] developed a fully coupled finite-element model to study porosity seepage, fluid flow in fractures, and rock deformation. Their simulations demonstrate that implementing biodegradable steering materials can enhance fracture complexity and eliminate cohesive drag at crossing points.

Tight oil reservoirs in the Sichuan Basin have a large number of natural fractures, which exacerbate the filtration of the fracturing fluid. The large amount of fracturing fluid percolation not only affects the fracture length, but also significantly increases the risk of sand entrapment [26]. Ali Telmadarreie et al. [27] reported on the application of foam using a combination of nanoparticles and surfactants to create a highly stable fluid with low leakage rates and non-damaging properties. Yin Zhong et al. [28] provided new information on the use of nanoparticles (NPs) as filtrate-reducing agents in hydraulic fracturing of shale reservoirs. It is important to emphasize the significant finding from the beginning of the paper: that nanoparticles have a new application in hydraulic fracturing of shale reservoirs. The filtration control effect of $CaCO_3$ as a hydraulic fracturing fluid additive in shale reservoirs can be determined experimentally. Junpeng Zou et al. [29] developed a numerical model consisting of multiple viscous fluid elements to replicate the formation and spread of complex hydraulic fracture networks, including random intersection and branching. Furthermore, the study investigated the pervasiveness of natural fractures, as well as the impact of bonding strength on fracture propagation. Daobing Wang et al. [30] used the computational fluid dynamics (CFD)—discrete element method (DEM) two-way coupling algorithm to establish a multiphase flow model of temporary blocking agent migration in complex fractures. Mayur Pal et al. [31] proposed an efficient workflow for large-scale complex DFN network meshing, providing low-dimensional objects supported by quantitative results, with the aim of developing a software toolbox to interface with an underground multiphase flow simulator. The numerical simulation results show that temporary blocking agent migration is influenced by several factors, such as formation temperature, fracture complexity, carrier viscosity, and mass [32]. Secondly, the complexity of fractures affected the migration behavior as well, with more complex fractures leading to more challenging migration [33]. In addition, the carrier viscosity and the mass concentration of the temporary plugging agent were found to be important factors that influenced the migration efficiency. Furthermore, the flow state of the carrier fluid and the friction coefficient between particles also played crucial roles in the migration process [34,35].

This article uses Petrel software to establish a physical model of tight oil reservoirs in the Sichuan Basin and determines the optimal fracture spacing through productivity numerical simulation. Through fracturing fluid filtration experiments, excellent fluid loss additives were selected. Based on the results of the diversion test and the proppant migration visualization experiment, researchers were able to determine a suitable combination of proppants and the optimal mass ratio for tight hydraulic fracturing in the Sichuan Basin. As a result, a new fracturing technology has been developed that can significantly improve the production of shale reservoirs.

2. Materials and Methods

Through the tests of fracturing fluid loss, fracture conductivity, and proppant transport, the type and mass ratio of fluid loss additives and proppants were selected.

Fracturing fluid filtration test equipment is used for fracturing fluid filtration tests, which can accurately test the amount of fracturing fluid filtration loss after adding different fluid loss additives, so as to select high-performance fluid-loss-reduction agents.

The high-temperature and high-pressure fracture conductivity testing equipment was used to test the fracture conductivity of different proppants according to API standards, so as to optimize the proppant combination and mass ratio.

The proppant migration was analyzed using the proppant transfer plate tester, which was designed by the Southwest Oil and Gas Field Company. The proppant transfer plate tester consists primarily of a sand-mixing vessel, a displacement pump, and a tempered glass plate. The main components of the device are the tempered glass panels, which simulate the fracture. These panels have a length of 7 m and a height of 0.7 m. The rough inner walls of the tempered glass panels allow for a more realistic simulation of the effect of rough cracks on proppant migration. In this experiment, the fracturing fluid and ceramsite were mixed in the sand-mixing container. The fracturing fluid was then displaced into the tempered glass plates via the displacement pump. During the experiment, the shape of the sand bank was recorded in real time with a high-speed camera, and the shape of the sand bank was mapped using a digital method. In this experiment, the injection displacement of the sand carrier fluid was 50 L per minute, the viscosity of the fracturing fluid was 35 mPa·s, and the particle size of the ceramite was 40/70 mesh and 70/140 mesh.

The proppant and fluid loss additives used in the above experiments were 70/140 mesh, 40/70 mesh and 30/50 mesh ceramics, which are commonly used in fracturing at present, and the density of the ceramics was 2.5 g/cm^3.

3. Results and Discussion

3.1. Optimization of Fracturing Parameters in Tight Marl Reservoir

The Sichuan Basin marl tight oil reservoirs are characterized by strong heterogeneity, low porosity, and low permeability [36]. The lithology is mainly argillaceous limestone and limestone, and the argillaceous limestone and limestone appear alternately [37]. The T0C of the reservoir is 0.32–0.81, and the porosity of the reservoir is less than 2%. As shown in Figure 1, the reservoir space of marl in the Sichuan Basin is mainly intergranular pores and dissolution pores. Clay minerals are mainly talc, with a small amount of illite, montmorillonite, and chlorite.

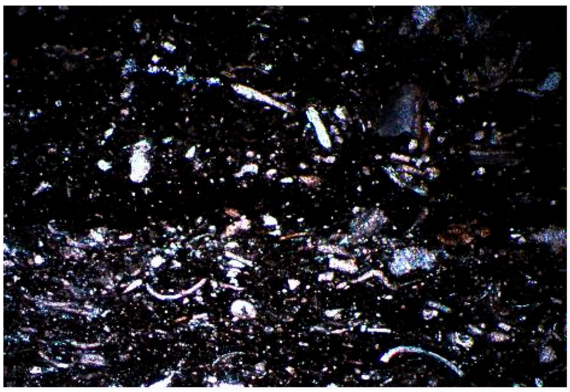

Figure 1. Microscopic characteristics of the core in well SC1.

Fracturing is a key technology to increase the production of tight oil in the Sichuan Basin. The key to fracturing design is the optimization of fracture parameters [38]. A reasonable fracture parameter will not only increase tight oil production, but also avoid cost wastage. This paper has developed a geological model for heterogeneous tight oil reservoirs based on the geological parameters and lithological distribution characteristics of tight oil reservoirs in the Sichuan Basin. Numerical simulation software was used to simulate productivity at different fracture parameters in order to select the most appropriate fracture design parameters for the tight oil reservoirs in the Sichuan Basin.

Marl reservoirs in the Sichuan Basin alternately develop mudstone and limestone along the track direction of the horizontal section. The lithological distribution of the marl reservoir is modeled in Figure 2. Mudstones not only have no contribution to oil and gas production, but also have a seepage shielding effect on oil and gas migration, thereby affecting the fracturing effect [39].

Figure 2. Lithological distribution diagram of the marl reservoir in the Sichuan Basin.

According to the reservoir distribution law in Figure 2, and taking the reservoir parameters of well SC1 as an example, a physical model of the marl reservoir in the Sichuan Basin was established using petrel software. The model is 1200 m long, 400 m wide, 60 m thick, and the grid step length is 10 m × 10 m × 10 m. In this model, limestone and mudstone are distributed in an alternating pattern, where limestone is 20 m thick and mudstone is 10 m thick. According to the real reservoir parameters of the SC1 well, the formation pressure coefficient of the physical model was set as 1.7, the porosity of mudstone was 2.07%, the porosity of limestone was 4.41%, the permeability of mudstone was 0.001 mD, the permeability of limestone was 0.0018 mD, and the oil saturation of the reservoir was 48%.

It can be seen from Figure 3 that the formation pressure distribution of the marl horizontal wells after fracturing for three years is discontinuous, especially the mudstone hinders the transmission of formation pressure to the limestone reservoir, and the mudstone will affect the fracturing effect. The fracturing design of the marl tight oil reservoir in the Sichuan Basin requires perforation in the limestone to ensure the extension of artificial fractures in the limestone and avoid the impact of mudstone.

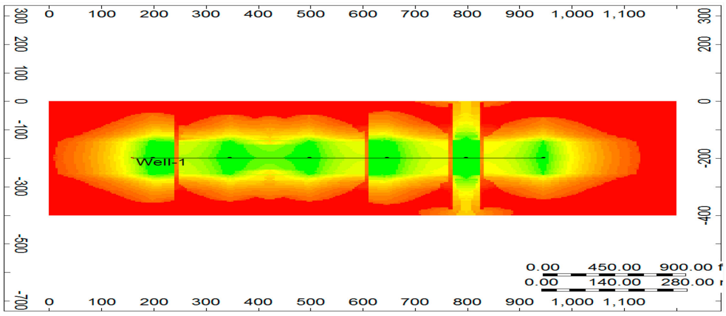

Figure 3. Formation pressure distribution of the marl horizontal well after fracturing for 3 years.

From Figure 4, it can be seen that as the spacing between artificial fractures decreases, the cumulative oil production of horizontal wells gradually increases. However, when the spacing between artificial cracks is 80 m, further shortening the spacing between artificial cracks does not produce a significant increase in cumulative oil production. This is mainly because when the spacing between artificial fractures is too small, the adjacent two artificial fractures will generate pressure disturbance, which will affect the production efficiency of the oil well [40].

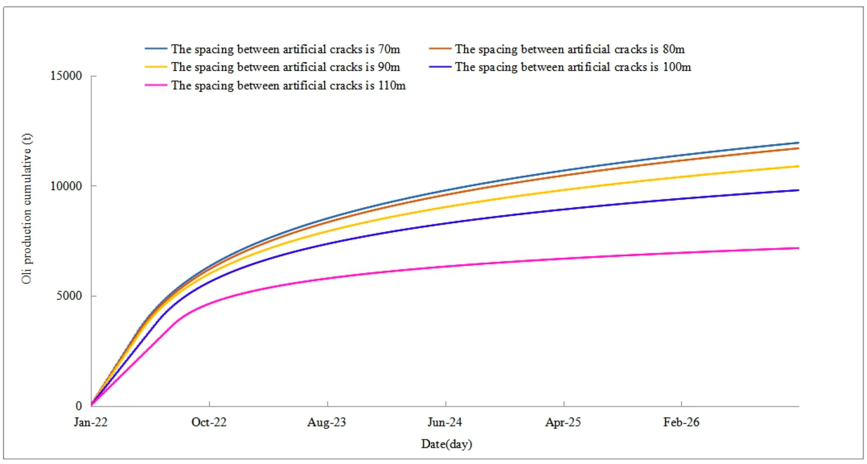

Figure 4. Accumulated oil production of horizontal wells with different artificial crack spacing.

3.2. Filtration Control Technology of Fracturing Fluid

The marl tight reservoir in the Sichuan Basin contains a large number of natural fractures [41]; natural fractures can exacerbate the filtration of fracturing fluid, thereby reducing the efficiency of the fracturing fluid and resulting in a shorter fracturing fracture length [42]. Therefore, for tight marl reservoirs in the Sichuan Basin, controlling the filtration of the fracturing fluid is a key issue that must be considered in the fracturing design.

This paper split the core taken from the tight oil well in the Sichuan Basin into two parts using the Brazil splitting method to simulate the natural fracture, laid 70/140 mesh ceramsite, 40/70 mesh ceramsite, and 30/50 mesh ceramsite on the end face of the core, tested the filtration performance of the fracturing fluid with a dynamic filtration meter, and optimized the fluid loss additive by comparing the filtration amount of the fracturing fluid.

From Figure 5, it can be seen that as the diameter of the added ceramic particles decreases, the filtration loss of the fracturing fluid gradually decreases. Especially after adding 70/140 mesh ceramic particles, the filtration loss of the fracturing fluid within 14 min is 43% lower than that of the fracturing fluid with 30/50 mesh ceramic particles. This is mainly because the natural fracture width of the marl tight oil reservoir in the Sichuan Basin is very small. Compared with 40/70 mesh ceramsite and 30/50 mesh ceramsite, small-sized ceramsite, such as 70/140 mesh ceramsite, enters the internal part of the natural fracture more easily, thus effectively plugging the natural fracture.

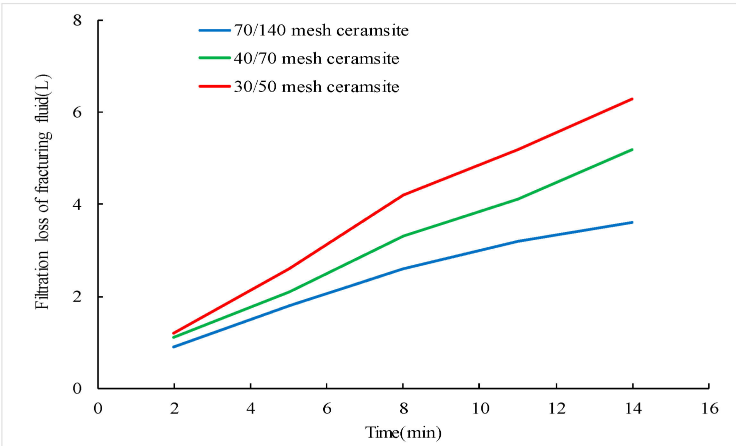

Figure 5. Changes in filtration performance of fracturing fluid after adding different fluid loss additives.

Through the liquid filtration test, the performance of different types of fluid loss additive was evaluated, and a 70/140 mesh ceramsite was selected as the fluid loss additive for the tight marl reservoir in the Sichuan Basin.

3.3. Study on the Conductivity and Placement Form of Proppant

Proppant is the soul of tight oil pressure fractures. Proppant plays the role of supporting the fracture and providing a channel for oil and gas flow. The Young's modulus of the marl reservoir is low, and the proppant can be easily embedded in the rock. This article uses a proppant embedment tester to conduct embedment tests on different sizes of proppants and analyzes the embedment depth of proppants using scanning electron microscopy.

First, we split the marl core in the Sichuan Basin to form a fracture, and then we spread 70/140 mesh ceramsite, 40/70 mesh ceramsite, and 30/50 mesh ceramsite on the fracture surface. The above ceramsite was uniformly distributed on the fracture surface at a concentration of 2.5 kg/m^2. We applied a pressure of 30 MPa on the surface of the rock core to force the fracture to close for 2 min. Finally, we quantitatively analyzed the depth of proppant insertion using scanning electron microscopy.

Table 1 and Figure 6 show that the embedment of ceramsite in marl increases with the increase in ceramsite diameter. If the ceramsite is embedded deeply, it will affect the conductivity of the fracture [43].

Table 1. Insertion depth of proppant.

Proppant	Closure Pressure/MPa	Insertion Depth/mm
70/140 mesh ceramsite	30	0.0118–0.0294
40/70 mesh ceramsite		0.0336–0.0727
30/50 mesh ceramsite		0.0587–0.0986

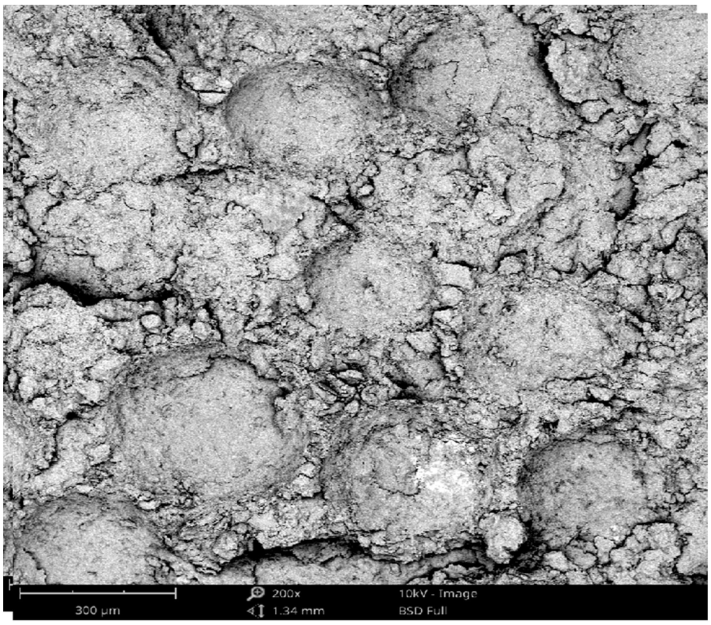

Figure 6. Embedment of 40/70 mesh ceramic observed via electron microscopy.

In this paper, the conductivity of different combinations of proppant is evaluated using the conductivity tester, and the optimal proppant combination is selected by comparing their conductivity differences. The proppant spreading concentration of the experiment is 2.5 kg/m^2, and the closure pressure refers to the actual situation in the marl reservoir in the Sichuan Basin. Thus, the closure pressure of the experiment is set to be from 20 MPa to 40 MPa. The ceramsite with two particle sizes is evenly spread on the fracture according to the mass ratio of 5:5.

From Figure 7, it can be seen that, compared to other combinations of proppant, the conductivity of the mixture of 70/140 mesh ceramic and 40/70 mesh ceramic is the highest. When the closure pressure is 20 MPa, the conductivity of a mixture consisting of 70/140 mesh ceramic and 40/70 mesh ceramic particles is 10.2% higher than that of a mixture consisting of 70/140 mesh ceramic and 30/50 mesh ceramic particles. When the closure pressure is 40 MPa, the conductivity of a mixture of 70/140 mesh ceramic and 40/70 mesh ceramic is 35.6% higher than that of a mixture of 70/140 mesh ceramic and 30/50 mesh ceramic.

The porosity and permeability of the marl reservoir are low; fracturing requires a high fracture conductivity, and a high fracture conductivity is conducive to the migration of oil and gas from the formation to the wellbore [44]. As a result, a combination of 70/140 mesh ceramics and 40/70 mesh ceramics was selected for the proposed fracture marl reservoir in the Sichuan Basin.

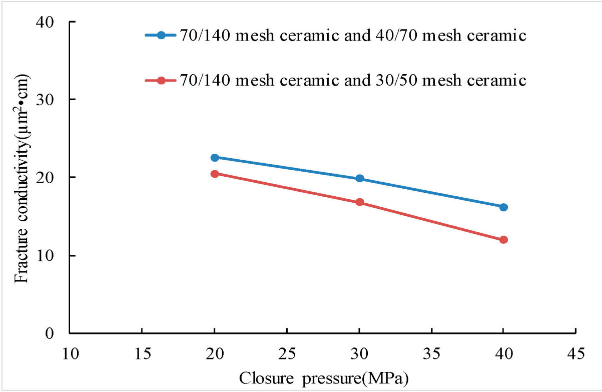

Figure 7. The conductivity of different combinations of proppant.

The objective of fracturing the marl reservoir is to establish an oil and gas migration channel from the formation to the wellbore by creating a long artificial fracture. As the pressure of the formation decreases, the fracture gradually closes, so that only the fracture supported by the proppant is valid. To accurately evaluate the placement of the proppant in the artificial fracture of the marl reservoir, a proppant migration flat plate tester is used to evaluate the migration law of 70/140 mesh ceramsite and 40/70 mesh ceramsite with different volume ratios in the fracture. This paper aims to determine the most effective combination of proppants for fracturing the marl reservoir in the Sichuan Basin.

As can be seen from Figure 8, the length of the sand dike formed by the mixture of 70/140 mesh ceramsite and 40/70 mesh ceramsite with different mass ratios in the fracture is not different, but the balance height of the sand embankment is quite different. The balance height of the sand embankment is largest when the mass ratio between the 70/140 mesh ceramics and 40/70 mesh ceramics is 6:4. As the mass ratio of the 40/70 mesh ceramics in the composite ceramic decreases, the equilibrium height of the sandbank gradually decreases.

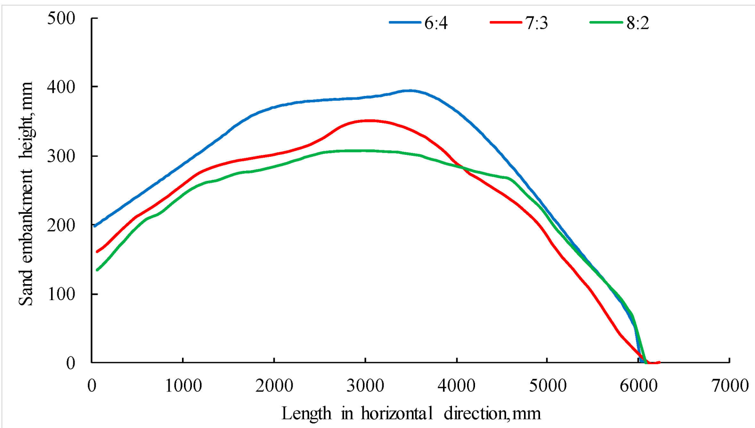

Figure 8. Sand bank diagram of 70/140 mesh ceramics and 40/70 mesh ceramics with different mass ratios.

The higher the balance height of the sand embankment, the wider the proppant fracture, so this paper selected 70/140 mesh ceramics and 40/70 mesh ceramics with a mass ratio of 6:4 as proppants for marl fracturing in the Sichuan Basin.

3.4. Field Application

The SC1 well is located in the east of the Sichuan Basin, with a reservoir burial depth of 4200 m and a reservoir temperature of 110 °C. The reservoir lithology of the SC1 well is mainly argillaceous limestone, and the distribution characteristics of mudstone and limestone are alternate. The SC1 well was fractured by slickwater, and a total of 1900 m^3 of slickwater was used to stimulate operation. A total of 1820 t of 70/140 mesh ceramics and 1210 t of 40/70 mesh ceramics was added to the slickwater. The injection displacement of slickwater was 18 m^3/min, and the reason for injecting slickwater with such a large displacement was to increase the bottom hole pressure as much as possible, thereby improving the fracturing effect. As shown in Figure 9, the wide-area electromagnetic method shows that the fracturing fracture length of SC1 reached 129 m, indicating that the SC1 well had been fully stimulated. Reservoir physical parameters of the SC2 well are similar to those of the SC1 well. Previously, the SC2 well was fractured with the same fracturing fluid dosage and the same displacement rate as the SC1 well, and the fracture length of the SC2 well was only 98 m. The fracture length of the SC1 well is 31.6% longer than that of the SC2 well, which further proves that the fracturing technology developed in this study can improve the fracturing effect of tight oil reservoirs.

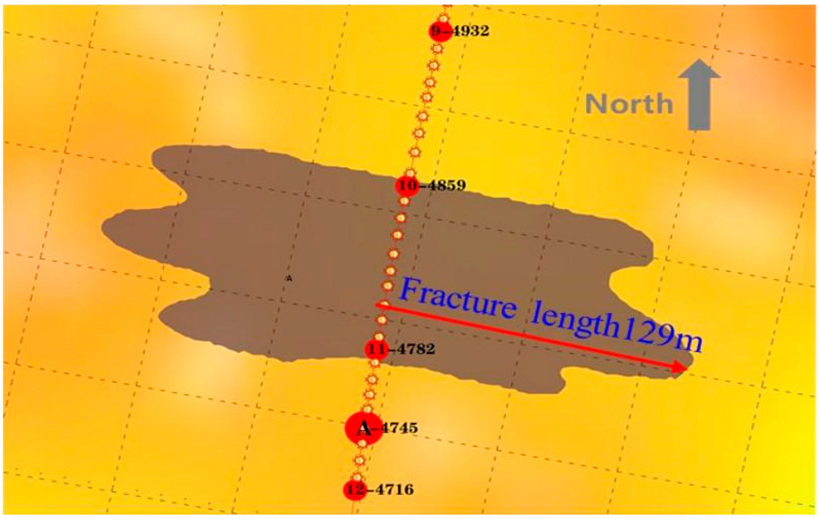

Figure 9. Fracture morphology of the SC1 well monitored via wide-area electromagnetic method.

4. Conclusions

(1) Mudstone will shield the seepage of oil, and the fracturing of marl horizontal wells needs to ensure perforation in the limestone reservoir. At the same time, numerical simulations have shown that the optimal fracture spacing for fracturing the Sichuan Basin argillaceous limestone reservoir is 80 m.

(2) The 70/140 mesh ceramsite can effectively reduce fracturing fluid loss and is the best fluid loss additive for argillaceous limestone reservoirs in the Sichuan Basin. The fracturing fluid loss of 70/140 mesh ceramides is 43% less than that of 30/50 mesh ceramides.

(3) To increase fracture conductivity and length, a mixture of 70/140 mesh ceramic particles and 40/70 mesh ceramic particles with a mass ratio of 6:4 is recommended as the fracture proppant. The fracture monitoring results of the SC1 well show that the fracture length of the combined ceramite can reach 129 m.

Author Contributions: Y.W.: Conceptualization, funding acquisition, project administration, resources, methodology, writing—original draft, writing—review and editing, investigation, visualization, and software. Y.F., S.L., Z.L., R.H. and L.W.: Data curation, formal analysis, writing—original draft, writing—review and editing. All authors have read and agreed to the published version of the manuscript.

Funding: This work was supported by the Project of the PetroChina Southwest Oil and Gas Field Company (Nos.: 20200302-14, 20210302-19, 20220302-11).

Institutional Review Board Statement: Not applicable.

Informed Consent Statement: Not applicable.

Data Availability Statement: Data is contained within the article.

Acknowledgments: The authors are grateful for the support of the PetroChina Southwest Oil and Gas Field Company. Thanks to the reviewers and editors for their careful review of this manuscript.

Conflicts of Interest: Author Yang Wang was employed by the PetroChina Southwest Oil & Gasfield Company. The remaining authors declare that the research was conducted in the absence of any commercial or financial relationships that could be construed as a potential conflict of interest.

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