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Massive Separate-Layer Hybrid Fracturing in Deep HPHT Naturally Fractured Condensate Gas Reservoir, Tarim Basin

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Abstract: *Dibei gasfield, located in Kuqa, Tarim basin, is a naturally fractured tight sandstone condensate gas reservoir. The reservoir formation is characterized by ultra-deep depth (4600m-5200m), massive thickness (100m-200m), low abundance, low matrix permeability, high pressure (80MPa -95MPa) and high temperature (140 ℃-150 ℃). Separate-layer hybrid fracturing has been adopted to enhance well productivity.*

In order to increase well production with long lateral interval, separate-layer hybrid fracturing with composite diverting agent has been used together with other accessory technologies. The low damage high-temperature weighted fracturing fluid and high-strength proppant were used to reduce the effect of reservoir sensitivity with high clay content and keep high conductivity. The large-diameter fracturing string with connection of 3-1/2″and 4-1/2″ was used to decrease pump pressure and increase the pump rate. The composite diverting agent was used to improve vertical stimulation efficiency.

With above technologies, two-layer hybrid fracturing was implemented successfully in a naturally fractured tight gas well. The fracturing used 1328 cubic meters of fracturing fluid and 50 cubic meters of proppant in total, and was done at the pumping rate of 8 cubic meters per minute and maximum pump pressure of 92MPa. The treatment pressure was increased by 4.0MPa when the composite diverting agent was pumped in at the beginning of the second layer fracturing. The sharp increase of pressure showed that the first layer was plugged temporarily by composite diverting agent and a new fracture was generated in the second layer at the same time. After fracturing, the well had a daily gas rate of 16300 cubic meters and daily oil rate of 5.6 cubic meters, much higher than before fracturing. In general, the stimulation result was non-ideal because of formation complexity.

We have obtained some experience of separate-layer hybrid fracturing in Dibei reservoir, and the introduction about the stimulation history in this paper can provide important reference for stimulation design in similar reservoirs.

Keywords: *hydraulic fracturing; deep layer; HPHT; optimization design*

1. INTRODUCTION

Dibei gasfield is located in the Dibei 1 Structure of Debei Slope in the north of Kuqa Depression. The Dibei 1 Structure is a large fault nose controlled by Ichicklick thrust fault plunging towards south in near EW trend, about 9 km long and 5 km wide, in which there are some secondary faults. The main reservoirs there include the Jurassic Ahe Fm. and Yangxia Fm., which are characterized by stable lateral distribution, low porosity and low permeability, strong fracture heterogeneity, gas-bearing universality but low gas abundance, and high yield in sweet spots.

The exploration and development of Dibei gasfield underwent 3 stages. The first one targeted at surface oil seeps and structures in shallow strata (1951 - 1983), the second one (1994 - 2002) extended to deep strata, with discovery of Yinan 2 gasfield; the well leading to the discovery of Yinan2 gasfield, Well Yinan2, had a converted daily gas yield of 108612 m3 from well section 4578 - 4783m with 4.76 mm choke at the tubing pressure of 26.26 MPa during drill-stem tesing. And the third stage (2010-2014) with the introduction of the theory of tight sandstone gas, the Jurassic Ahe Formation in East Kuqa was picked out as the most promising tight sandstone gas reservoir, and key technical problems for the Jurassic exploration in Dibei were studied deeply; high yield was obtained from Wells Dixi 1 and Dibei 104 by nitrogen drilling.

Fifteen wells have been completed in this area using different drilling techniques, including nitrogen drilling, oil-based mud drilling, and water-based mud drilling. Although different stimulation technologies, including conventional acidizing, small-scale fracturing, large-scale acid fracturing and composite fracturing, were adopted, the overall effect was not very good, only 5 wells obtained high-yield oil and gas flow, and the percentage of wells with commercial oil and gas yield was low, indicating high complexity of Dibei gas reservoir.

We had a better understanding on the complexity of Dibei gas reservoir through reviewing the fracturing and evaluating the fracturing effect of Well Dibei 102, a typical well in the reservoir.

2. OVERVIEW OF DIBEI GASFIELD

2.1. Reservoir structure

Kuqa Depression, located in the north of Tarim Basin, is adjacent to South Tianshan faulted fold belt to the north, Tabei uplift to the south, and stretches from Yangxia sag in the east to Wushi sag in the west. It is a superimposed foreland basin filled dominantly by the Mesozoic, Cenozoic deposits. Yiqikelike thrust belt, located in the east of Kuqa Depression, is about 120 km long and 15 – 25 km wide. It is adjacent to South Tianshan to the north, Qiulitag thrust belt to the south, Kelasu thrust belt to the west, and Mingbei thrust belt to the east. Affected by Yanshan and Himalaya tectonic movements, Yiqikelike thrust belt was characterized by the classic features of foreland deformation, where Yiqikelike fault thrusted up to ground surface, leading to development of a series of EW trending linear anticlines on its hanging wall and a series of fault noses, faulted anticlines and anticlines. Fault Nose Dibei 1 is located in the middle segment of Yiqikelike thrust belt, where many faults developed as a result of compressional stress in SN direction.

Dibei gas reservoir is located within the Fault Nose Dibei 1 of North slope in the structural belt in the north of Kuqa Depression, with the Jurassic Ahe Fm. as the major reservoir. The reservoir about 260 m thick is mainly composed of light grey - gray sandstone, with stable lateral distribution. It is in parallel unconformable or paraconformable contact with the underlying strata. According to the lithological association, it is divided into 4 lithologic members, glutenite with mudstone member, upper glutenite member, lower glutenite member, and thick mudstone member between them. The glutenite with mudstone member mainly consists of gray medium sandstone, coarse sandstone and conglomeratic sandstone, with thin mudstone, argillaceous siltstone, and a set of medium - thick carbonaceous mudstone and mudstone at the bottom. The upper glutenite member is composed of thick - mega-thick coarse conglomeratic sandstone, coarse sandstone, mega-thick medium sandstone, fine sandstone with thin – medium thick mudstone. The glutenite section is composed of thick - mega-thick coarse conglomeratic sandstone, gravelly sandstone, interbeds of thick - mega-thick coarse sandstone, medium sandstone, and fine sandstone in different thickness, with medium thick mudstone interlayers.

Well Dibei 102 is an appraisal well located on the northwest flank of Fault Nose Dibei 1 at the footwall of Yiqikelike thrust belt in the east of Kuqa Depression, Tarim.

2.2. Basic features of reservoir

2.2.1. Lithology

The Ahe Fm. gas reservoir is mainly composed of lithic sandstone and feldspar lithic sandstone, in which detritus consists of quartzite, phyllite, granite, and rhyolite. The sandstone grains are medium - well sorting, subangular - subrounded, in linear-convex contact, grain-supported, pore cemented, and medium – high in component maturity and structure maturity. The sandstone has an average quartz content of 33.68%, feldspar content of 13%, and debris content of 37.20%. The fillings accounting for 12.40% averagely, mainly consists of calcite, silicon and clay. The clay minerals making up 5.55% averagely, are composed of hair-like illite dominantly, followed by sheet-like illite and illite - smectite mixed layer.

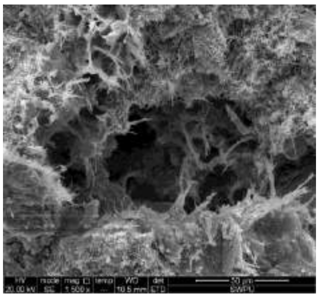
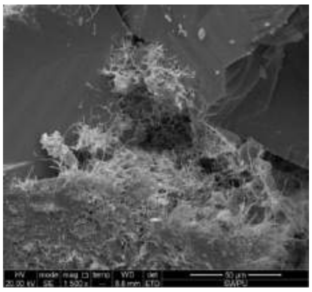



Fig 1 *Intergranular pore filled with hair-like illite* **Fig 1** *hair-like illite*

2.2.2. Physical properties

From logging interpretation, the gas layers, poor gas layers are 122.5m thick, 4.7 - 9.9% in porosity, 45.0 - 74.0% in oil saturation, and around 0.01 mD in matrix permeability generally.

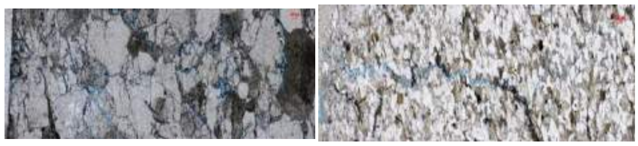
The core physical property test show that the Ahe Fm. reservoir in Well Dibei 102 has a porosity of 1.9% - 10.3%, 5.69% on average, and permeability of 0.004 mD - 61.94 mD, 1.08 mD on average, representing ultra-low porosity and permeability one.

The reservoir permeability interpreted from drill-stem testing was 0.0018 mD, suggesting the reservoir is of ultra-low permeability. Moreover, the pressure recovered slowly during late shut-in, derivative curve shows upward boundary in late stage and low production, indicating that the distant formation has poorer petrophysical properties or boundary reflection, and may be fault boundary or lithologic reservoir characteristics.

2.2.3. Fractures in the reservoir

The reservoir has few fractures. FMI logging interpretation shows a fracture density of 0.06/m, and the fractures are trending near SN are concentrated in the intervals with high shale content. With dip angles of about 70°, they are high angle oblique fractures.

Observation of casting thin sections and scanning electron microscopy (SEM) analysis show that the Ahe Fm. gas reservoir is rich in micro-fractures, with a density of 1-7 per thin section. They are 3 - 15 mm long, and 10 - 50 m wide. Fractures, as high-speed seepage channels in the tight low-permeability sandstone gas reservoir, are crucial for high, stable yield of gas reservoir.



Well Dibei102 5029.10m J_1a^2 Well Dibei102 5033.50m J_1a^2

Well Dibei102 5090.55m J_1a^2 Well Dibei102 5033.50m J_1a^2

Fig 2 *thin-section photos for microfracture in core*

2.2.4. Microscopic pore structure

The Ahe Fm. gas reservoir is tight by strong cementation, low in porosity and poor in pore connectivity. The reservoir space mainly includes intragranular dissolved pores and moldic pores, followed by intercrystalline pores, and intercrystalline pores and residual intergranular pores occasionally.

The reservoir has a displacement pressure of 0.14 - 2.51 MPa, maximum throat radius of 0.29 - 5.25 μm, mean value of saturation pressure of 0.89 - 46.80 MPa, mean value of throat radius of 0.02 - 0.83 μm, and the mainstream value of throat radius of 11 - 40 μm. In conclusion, its pore throat structure is poor.

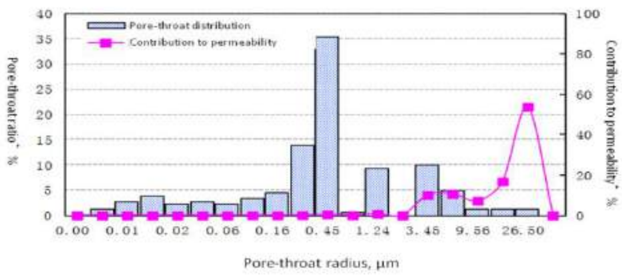


Fig 3 *core pore-throat distribution diagram of well Dibei 102*

2.2.5. Characteristics of rock mechanics

According to logging interpretation, reservoir section in this well has a Young modulus of 15 - 41 GPa, on average 32G Pa, and Poisson's ratio of 0.1 - 0.3, on average 0.2, showing the mechanical characteristics of tight rock. The uniaxial compressive strength (UCS) ranges from 41 to 76MPa, on average 120MPa. The core test shows that the Young modulus ranges from 21 to 35 GPa, and the Poisson's ratio ranges between 0.139 and 0.221, which are consistent with the logging results.

The reservoir section has a minimum horizontal principal stress of 102 - 116MPa, on average 107 MPa, maximum horizontal principal stress of 110 - 150MPa, on average 135 MPa. The horizontal maximum principal stress orientation is about NNE 18°, which is consistent with the strike of natural fractures, conducive to the opening of fractures.

There is an obvious hydraulic barrier at the top of the reservoir, which has a minimum horizontal principal stress about 10MPa higher than that of the reservoir. Moreover, there are obvious hydraulic barriers at 5110 m and 5140 m in the lower part of the reservoir, which have a minimum horizontal principal stress about 5 MPa higher than the adjacent layers.

Table 1 *Rock mechanics parameters of well Dibei 102*

Well No.	Depth m	Core No.	Confining pressure MPa	（σ1-σ3） MPa	E MPa	ν	BI %	Fitting UCS MPa
Dibei 102	5141.38	A-V	52.00	324.84	34510	0.202	48.32	173
		A-h	20.00	245.74	29670	0.196	46.29	
		A-45	0.00	155.26	--	--	--	
		A-H	30.00	310.75	24350	0.202	41.97	
Dibei 102	5145.71	B-V	52.00	349.50	26020	0.184	46.01	110
		B-h	20.00	236.45	26410	0.221	40.09	
		B-45	0.00	53.84	--	--	--	
		B-H	30.00	261.70	21060	0.139	50.41	

2.2.6. Temperature and pressure

Based on well logging, the well temperature is 138℃, the extrapolated formation pressure is 66.012 MPa, with pressure coefficient of 1.37.

3. METHODS OF FRACTURING OPTIMIZATION DESIGN FOR WELL DIBEI 102

3.1. Fracturing design difficulties

1) Since the reservoir is characterized by low porosity and low permeability, and low permeability boundary was detected during well test, it is necessary to enlarge the fracturing scale to produce fractures long enough to break through the low permeability zone, connect high permeability zones further from the well, and expand well drainage area. However, as the reservoir has some natural fractures, which would increase the geometric complexity of fractures and increase the fluid loss volume, making it difficult to generate main fractures.

2) The reservoir is thick, with the span of gas reservoirs of over 284 m, and the effective thickness of 122.5 m, moreover there are mudstone interlayers in the reservoir, so it is difficult to produce from the whole reservoir section.

3) The well is very deep with high pressure, so it is difficult to run in and operate the tools for mechanical layer separation, and the fracturing would have high risks.

4) Due to the high crustal stress and Young modulus of the reservoir, fractures would be hard to initiate and extend, and small in width, with high risk of sand plug.

3.2. Technical measures

1) The low matrix porosity and permeability, underdeveloped natural fractures, and direction consistency of the maximum principal stress and natural fractures, are not conducive to formation of complex fracture network. The fracturing would use the composite pad fluid of gel and sand to produce long double-wing fractures. During pad fluid stage, a large volume of slickwater and sands of 70/140 mesh would be pumped into the reservoir to plug possible natural fractures, reduce fluid leak-off, and protect micro-fractures to help generate long fractures.

2) The gel sand fracturing would utilize the fiber sand-carrying method to prevent excessive settling of proppant that would affect the proppant placement negatively.

3) The fiber plugging technology would be adopted, in which high-concentration fiber diverting agent would be injected after fracturing of one stage completed to realize temporary plugging and fracturing of a new stage, and improve the vertical producing degree of thick reservoir.

4) To reach the goal of producing fracture network, clustering perforation was adopted in this well. The perforations were designed to be in positions with few natural fractures but near natural fracture. This can reduce the fluid loss at the beginning of hydraulic

fracture opening, and guarantee that fractures could extend to the areas with natural fractures in later stage. There were 8 perforated intervals with a total thickness of 16m designed.

5) The fracturing string with connection of and 4-1/2″was used to decrease frictional resistance, ensure pumping rate, and reduce fracturing risks.

6) Micrometre-scale natural micro-fractures rich in the reservoir are the main contributor to productivity. However, the micro-fractures are very sensitive to stress, so the proper production system should be selected to control decline rate of the bottom hole pressure in the process of flowback and blowout.

4. EVALUATION AFTER FRACTURING

4.1. Fracturing overview and effect analysis

The well was treated on September 28, 2013, a total of 1328.6 m^3 fluids was injected, including 600 m^3 of slickwater of and 728.6 m^3 of fracturing fluid. The treatment curve shows that the maximum pumping rate was 8m^3/min, maximum injection pressure was 92 MPa, 50 cubic meters of proppant was injected, and the shut-in pressure was 53.5 MPa. 15 minutes after pumping was stopped, the treatment pressure reduced to 48. 3 MPa, with pressure drop rate of 0.0 MPa/ min.

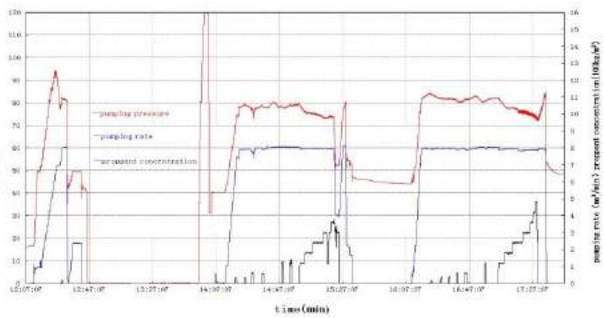


Fig 4 *Fracturing treatment curve of Well Dibei 102*

After fracturing, well tests with 5.00 mm choke achieved tubing pressure of 11.415MPa, and daily gas and oil yield of 5.64 m^3 and 16328 m^3, respectively. Well tests with 4.00 mm choke achieved tubing pressure of 9.566 MPa, and daily gas and oil yield of 3.36 m^3 and 7988 m^3, respectively. Well tests with 6.00 mm choke achieved tubing pressure of 5.997 MPa, and daily gas and oil yield of 2.85 m^3 and 13902 m^3, respectively. Compared with the DST production (oil pressure of 9.679MPa, daily oil and gas yield of 8.2 m^3 and 1491 m^3 with 3.00 mm choke,), the stimulation effect is not significant. After fracturing, liquid flowback was smooth, a cumulative of 1061.26 m^3 liquid was recovered in 12 days, with a flowback ratio of 79.9%, indicating high flowback efficiency and velocity.

4.2. Evaluation of fracture geometry

The fitting result of treatment pressure shows that multiple fractures were generated during fracture propagation after temporary plugging and diverting. The propped fractures are short, and they extend not long enough laterally (105 m at most), and inadequate in conductivity (8.5D·cm at most). Longitudinally, the fractures are mainly distributed in perforated intervals where fracturing fluids are easy to get into, and do not form effective support throughout the whole fractured interval, resulting in limited stimulation degree and scope vertically.

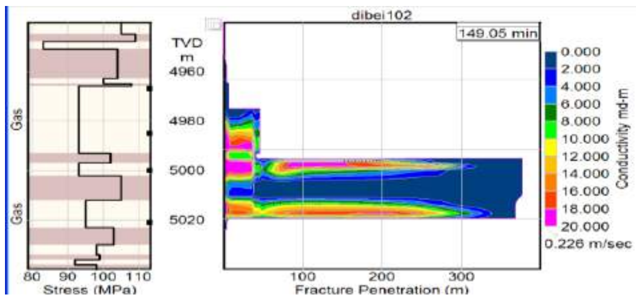


Fig 5. *pressuer matching fracture profile of well Dibei 102*

4.3. Evaluation of temporary plugging effectiveness

The treatment pressure increased by up to 4.0 MPa after diverting agent was pumped in at the second layer fracturing, and the shut-in pressure drop of these two layers show remarkably different decline rates, namely, 0.46 MPa/min and 0.18 MPa/min respectively, and trend, indicating that reservoirs with different permeability have been fractured.

Table 2. *treatment parameters comparison before and after diversion*

Layer No.	IPIP MPa	Pressure drop rate MPa/min	Extended pressure gradient MPa/100m	Pumping rate before and after diversion 8m^3/min	Pressure before and after diversion MPa
1st layer	47.2	0.18	0.0203	8.0/8.0	80.3/84.3
2nd layer	53.5	0.46	0.0215		

5. CONCLUSIONS

1) The massive hydraulic fracturing of the well was successfully completed by using hybrid separate – layer fracturing technology. The total fluid volume injected into the well was 1328.6m^3, including 600m^3 of slickwater and 728.6 m^3 of fracturing fluid. The maximum pumping rate and pumping pressure were 8m^3/min and 92 MPa respectively, and the proppant volume injected was 50.1 m^3.

2) Although large-scale fracturing has been successfully implemented and temporary plugging has been realized, the stimulation effect is not ideal by comparing production before fracturing with that after fracturing, which suggest that fractures created have not extended beyond the low permeability boundary belt around borehole and connected with natural fracture system further from the borehole, and also temporary plugging has not realized the effective producing of the whole reservoir section. so more effective stimulation techniques, such as horizontal well with PNP multi-stage should be applied in the next step.

3) The massive hydraulic fracturing was implemented successfully and the fracturing fluid flowback ratio is up to 79.9%,which indicates that the fracturing fluid has strong ability to suspend proppant and low damage to reservoir.

4) For the naturally fractured gas reservoir, the development degree of fracture is a main controlling factor for high oil and gas yield. The strong heterogeneity of fractures is the main reason behind the poor stimulation effect.

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