Research on integrative multi-media modelling and simulation method for tight formation horizontal well development

Jiaxin Dong1,3, Wen Shi2, Fan Yang1 and Lifeng Liu1

1 Research Institute of Petroleum Exploration & Development, No.20 Xueyuan Road, Haidian District, Beijing;
2 China Petroleum Technology and Development Corporation, No.8 Jinxingyuan, Chaoyang District, Beijing
3 Email: djx1021@petrochina.com.cn

Abstract. Tight formations usually have large area of coverage. There is large areal heterogeneity for reservoir petrophysics, rock facies, formation thickness, physical properties and oil saturations, in different reservoir blocks, in area between different wells, and also in different segments of a single well. Tight reservoirs have different scales of natural fracture development. Hydraulic fracturing also forms different scales of complex hydraulic fracture network, which has large macroscopic heterogeneity with prominent multi-scale features. Unconventional tight reservoirs consist of different scales of porous media from nano-sized to nano-micron to micron-sized. There is large difference for compositions and quantity distributions in pore spaces with different scales. Different scales of pores present discrete discontinuous distribution in space, with large heterogeneity in spatial distribution. There is large difference for geometric parameters and physical properties in different scales of porous media. Different scales of pores present large microscopic heterogeneity and multiple porous media features. All of these features make conventional reservoir modelling and numerical simulation theory and technology not applicable in this scenario. In this paper, a new multi-media modelling and simulation method for volume fracturing of horizontal wells in tight reservoirs is introduced in detail by using the unconventional reservoir modelling software Untog, taking a single well as an example.

1. Preface

Porous media of different scale, ranging from nano level, nano-micon level to micron level co-exist in the unconventional tight reservoirs. The composition and quantity distribution pattern of pores at different scales is quite different. The pore distribution pattern at different scales is discrete and discontinuous. At the same time, the spatial distribution pattern is also quite different. The geometrical and physical parameters of porous media at different scales are various, showing strong micro-heterogeneity and multi-media characteristics, and leading to the complexity and diversity of flow mechanism which result in the significant differences in flow characteristics. According to the large areal heterogeneity for tight reservoirs’ petrophysics, rock facies and reservoir categories, large macroscopic heterogeneity, multi-scale features and microscopic multiple media existing in the development of porous media with fractures in different scales. A new technology for building discontinuous multi-scale multiple media reservoir model is developed, the simulation of discontinuous-discrete-multiple media was innovatively developed.
2. Modelling technology of discontinuous multi-scale discrete multi-media reservoir

Tight formations have large macroscopic heterogeneity for petrophysics, rock facies, reservoir types, development and scale of natural fractures, magnitude and direction of crustal stress and flow properties in spatial distribution. Conventional reservoir modelling theory and technology are not applicable[1-3]. According to the macroscopic scale and intensity of heterogeneity, the tight formations can be divided into first level domains based on large scale heterogeneity, second level representative elements based on small scale heterogeneity. Representative elements can be divided into third level multiple media based on the quantity and distribution of microscopic fractures with different scales.

Different scaled pore-fracture media and the heterogeneity characters can be fully embodied with this method. A sample modeling for a horizontal well X which is located in a tight oil block of China is elaborated in detail.

2.1. Artificial fracture modelling

According to the reservoir longitudinal variation pattern, the geological model of well X is divided into five layers, the thickness of each layer are exported from Petrel. Horizontal well mainly goes through the first and second layers. Based on the evaluation results of fracturing operation performance and the direction of formation stress, the artificial fracture model of well X is established (Table 1, Figure 1).

| Fracture Section | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 |
|------------------|---|---|---|---|---|---|---|---|---|
| Fracture Classification | Type I | Type II | Type I | Type II | Type I | Type II | Type I | Type II |
| Fracture Length/m | 530 | 435 | 514 | 328 | 519 | 554 | 550 | 540 | 423 |

2.2. Geological model zoning

According to reservoir classification criteria (Table 2), combined with regional lithology conditions, and based on logging interpretation results, large-scale zoning of each small layer plane is carried out, and a single well large-scale zoning geological model of well X is established (Figure 2-6).

Figure 1. Fracture model of well X.

Figure 2. The first layer model.

Figure 3. The second layer model.
Figure 4. The third layer model.

Figure 5. The fourth layer model.

Figure 6. The fifth layer model.

Table 2. Reservoir classification.

| Reservoir Type      | Deep Lateral Resistivity Logging, $\Omega \cdot \text{m}$ | Natural Gamma API | Porosity, % | Permeability, mD | Oil Saturation, % |
|--------------------|----------------------------------------------------------|-------------------|-------------|------------------|------------------|
| Reservoir Type-I   | $>21$                                                     | $<58$             | $>12$       | $>0.5$           | $>47$            |
| Reservoir Type-II  | $16-21$                                                   | $72-58$           | $10-12$     | $0.2-0.5$        | $43-47$          |
| Reservoir Type-III | $10-16$                                                   | $72-80$           | $8-10$      | $0.08-0.2$       | $38-43$          |
| Non Reservoir Type-IV | $<10$                                                   | $>80$             | $<8$        | $<0.08$          | $<38$            |

2.3. Multi-media geological model

Figure 7. Multi-media model of the first layer model.

Figure 8. Multi-media model of the second layer.

Figure 9. Multi-media model of the third layer.

Figure 10. Multi-media model of the fourth layer.

Figure 11. Multi-media model of the fifth layer.
Based on the pore distribution law of different scales of different reservoirs (Table 3), the proportion of different scales of pore in each reservoir can be obtained. The geological model of well X is established by furtherly dividing each layer according to pore scales and media type (Figure 7-11), the pore distribution of different types reservoirs is randomly distributed proportionally.

### Table 3. Volume proportions of various reservoir media.

| Reservoir Type | Media I (Small Pore), % | Media II (Micron Pore), % | Media III (Micro-Nano Pore), % | Media IV (Nano Pore), % | Average Porosity, % |
|----------------|------------------------|---------------------------|-------------------------------|------------------------|---------------------|
| Reservoir Type I | 50                     | 32                        | 11                           | 7                      | 13.86               |
| Reservoir Type II | 30                     | 32                        | 21                           | 17                     | 11.26               |
| Reservoir Type III | 15                     | 25                        | 40                           | 20                     | 9.3                 |
| Reservoir Type IV | 0                      | 3                         | 5                            | 92                     | 2.6                 |

#### 2.4. Fluid geological model

Under the action of hydrocarbon generation and capillary pressure, the state of fluid occurrence, availability and displacement difficulty are various in different media, and the permeability and capillary force curves are quite different (Figure 12-13). The Nano pore has narrow roar and poor connectivity, which result in the highest bound water saturation; The small pore has good connectivity and the bound water saturation is the lowest. Different scales of porous media have different capillary force curves. The denser the pore is, the higher the displacement pressure will be. Based on the laboratory test results, the phase permeability and capillary force curves of different pore scales in well X are determined (Figure 14-18).

**Figure 12.** Phase permeability curves of different scaled porous media.

**Figure 13.** Capillary force curve of different scaled porous media.

**Figure 14.** Oil saturation distribution model of the first layer.

**Figure 15.** Oil saturation distribution model of the second layer.
2.5. Geological reserve model

The geological reserve of well X area is 575,000 tons by volume method, while 571,800 tons by multi-media model. The good correspondence proves the rationality of the geological model. Furthermore, 29% of the reserve is from small pore, 31% is from micro pore, 23% is from micro-nano pore and 17% is from nano pore (Figure 19-20).

3. Numerical simulation for different scaled multi-media

Unconventional thigh reservoirs contain multi-scale pores and fractures. According to the seepage theory of continuous media, multi-scale porous media with fractures could be divided into continuous porous media and continuous fractured media with different geometric and property parameters. The simulation of continuous dual-porosity media has been developed, which includes simulation of dual-porosity single permeability media and simulation of dual-porosity dual permeability media [4,5]. Unconventional tight oil and gas reservoirs contain multi-scale porous/fractured media but those media discontinuously distribute in space so their properties also change discontinuously in space. There are huge differences in geometry, property and flow characteristics between those media. Conventional simulation for dual-porosity media [6-8] is difficult to explicitly represent those discontinuously-distributed media in tight reservoirs, consider multi-scale and multiple media characteristics of tight reservoirs and deal with multiple flow regimes and complex flow mechanisms.

In order to overcome these limits of conventional simulation for dual-porosity media, in this book, the innovative simulation is developed to deal with multiple flow regimes in discontinuous/multi-scale/multiple media.
3.1. Mesh generation
The macroscopic heterogeneity of spatial distribution of multi-scale natural/artificial fractures is strong. The characteristics of discontinuous discrete distribution and multi-scale of those fractures are obvious. Meanwhile, those fractures have a low density, poor connectivity and discontinuously variable properties and flow characteristics. It is difficult to use structured grid to deal with those fractures. As a result, in this research, the unstructured grid is used to deal with the discretization of those fractures.

Tight reservoirs contain discontinuous discrete porous media. For different scale pores, their quantitative distributions and spatial distributions have huge difference. Meanwhile, the discrete micro-nano fractures are massive and their scales are small. They cannot be treated as discrete fractures in simulations. In conventional simulations, different scale pores are treated as homogeneous continuous single porous media and different scale fractures are treated as homogeneous continuous single fractured media.

The above conventional simulation is the simulation for continuous dual porosity media. This kind of simulation cannot deal with production mechanisms and fluid flows between different scale pores and fractures, occurrence states of different scale media, and the impacts of difference in fluid property and fluid flow on production performance. Therefore, the different scale pores and micro-nano fractures in tight reservoirs are treated as micro scale discrete multiple media in this study. The simulation method for discontinuous discrete multiple media is used to innovatively build the simulation for different scale discrete multiple media in this study.

The graph shows the grid of well X. (Figure 21)

3.2. Historical matching
The production history of well X is simulated and the production of next 10 years is predicted (Figure 22). By fitting the bottom hole flowing pressure with daily production, the compliance between the matched pressure and the converted wellhead pressure is relatively good, which proves the reliability of the geological model. From the distribution map of formation pressure at the end of fitting, it can be seen that the formation pressure is mainly concentrated near the fracture, and the pressure in lower areas which is not controlled by fractures is higher (Figure 23-24).

![Figure 21. Grids of well X.](image1)

![Figure 22. Pressure distribution map after matching.](image2)

![Figure 23. Historical fitting curve of oil production.](image3)

![Figure 24. Bottom-hole flow pressure history fitting curve.](image4)
3.3. Future production prediction

The future production prediction of well X is made (Figure 25-27), and the results show that the cumulative oil production can be 19,587 tons in the next five years and 24,348 tons in the ten years. 68% of the production will come from small and micro pores. When the ten year production simulation is finished, the predicted stratum pressure distribution map indicates that the pressure drop mainly occurs near the artificial fractures, and is not significant in areas 50 meters away from the artificial fractures.

![Figure 25. Prediction of cumulative oil production curve for 10 years.](image1)

![Figure 26. Prediction of cumulative oil production in different scaled porous media for 10 years.](image2)

![Figure 27. Pressure distribution map after prediction.](image3)

From the oil saturation distribution map (Figure 28-30), it can be seen that the first layer and the second layer, which are drilled through by horizontal drilling, contributes the most productivity. The other layers only connected by fractures have less contribution to the productivity.

![Figure 28. Plane map of oil saturation change in the first layer.](image4)
4. Conclusions
(1) This geological modeling method can fully simulate the different scales of natural/artificial fractures developed in tight reservoirs, as well as the different scaled pores. The seepage parameters taken into calculation are various and specialized designed for different pore-fracture media.
(2) This numerical simulation technology uses different meshing methods and different calculation methods for different media, which can simulate the parameters of reserves and recovery degree in different scaled porous media. The prediction results are more accurate and reliable.

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