Prediction method of formation pressure for the adjustment well in the reservoir with fault

Liguo Zhong\textsuperscript{1,3}, Tianyin Zhu\textsuperscript{1}, Tongchun Hao\textsuperscript{1}, Xiaocheng Zhang\textsuperscript{2}, Xiaopeng Wang\textsuperscript{2} and Lei Zhang\textsuperscript{2}

\textsuperscript{1}China University of Petroleum (Beijing), China  
\textsuperscript{2}CNOOC (China) Co., Ltd. (Tianjin branch), Tianjin, China  
\textsuperscript{3}E-mail: zhongliguo007@163.com

Abstract. Adjustment wells need to be deployed in the middle and late stages of oilfield development to improve development efficiency. However, the multiple pressure systems would be happened in the fault block oilfields due to the geological faults are developed and multi-layer joint water injection. The well kick and leakage would happen during drilling and completion operations of adjustment well because of the large dynamic pressure changes such as high-pressure or low-pressure. A pressure prediction method established base on seepage theory and fluid mechanics theory in order to ensure the safety operations during the adjustment well drilling and completion. This method could predict the maximum formation pressure of adjustment wells in complex fault block reservoirs by considering the influence of faults and surrounding injection-production wells. The error between prediction results and numerical simulation results is less than 10\% based on Bohai fault block oilfield. The scheme of shut-in of surrounding water injection wells during drilling and completion of adjustment wells in fault block oilfield is given. This method has significance guidance for the design of shut in adjustment well drilling and completion.

1. Introduction

The general reservoir physical properties of fault block oilfields are very different\cite{1}, and the internal crude oil properties, productivity and dynamic characteristics are affected by the reservoir physical properties. Due to the influence of geological factors, the fluid properties and pressures of different blocks and different strata vary greatly. Generally, faults have many vertical oil-bearing layers\cite{2}, with strong fault sealing, complex oil-water relationship, strong reservoir heterogeneity, and inter layer contradictions would be very prominent. The development of faults in fault block oilfield and the imbalance of injection and production between layers are the main causes of uneven oil-water pressure distribution and drilling accidents in the development process. The injection-production relationship of fault block oilfields is complicated, and the formation pressure levels of each fault after development are very different. The problems faced by adjustment well drilling is mainly caused by ”formation pressure changes” during the injection-production development process. Due to the injection-production imperfection, ”only production without injection” or ”unbalanced injection-production” causes the pressure of the reservoir to drop continuously, forming low-pressure reservoirs, while faults, lithological changes and high water cut can cause abnormally high-pressure reservoirs or high-pressure area.
The problem of adjustment well drilling is mainly caused by "formation pressure change" in the process of injection production development. Accurate prediction of formation pressure is very important for oil and gas exploration and drilling [3, 4]. Commonly used formation pressure prediction methods are Eaton method and Bower method [5]. Eaton is based on the basis of compaction theory, and Bowers method fully considers the formation mechanism of abnormal pressure. Fillippone’s Fillippone formula, which uses layer velocity and does not depend on normal compaction, has also been successfully used [6-9]. Pressure prediction is currently usually carried out around one well or several adjacent wells in a limited area. According to the compaction seismic velocity data obtained by logging, the calibration parameters at each well can be determined, and the parameters between wells can be obtained by interpolation using effective stress method, such as the Bowers method [10, 11], and the measured wells Speed and pressure value can get pressure curve parameters. After determining the parameters, the parameters of each well location can be inserted into the seismic velocity function. In addition, with the Gardner relationship, the density parameter can be obtained at each well location and inserted into the velocity function. With the seismic velocity function and the interpolated calibration velocity, density and pressure values, the overlying pressure and pore pressure can be accurately predicted. In the 1990s, KSEPL Laboratory [12-15] used the thick-walled barrel experiment method and the elastoplastic finite element model (taking the rock as completely plastic) to evaluate the wellbore stability as formation pore pressure, fracture pressure and three pressure curves of collapse pressure.

In this paper, taking Bohai fault block oilfield as an example, according to the reservoir geological conditions and development characteristics of fault block oilfield, the main geological factors affecting the formation pressure system of injection production well pattern are clarified. Combined with the theory of seepage mechanics and fluid mechanics, the distribution law of reservoir fluid and pressure under injection production condition and its influencing factors are studied. The calculation method of the maximum formation pressure of adjustment wells in fault block oilfield is given, and the injection wells that need to be shut down during drilling and completion of adjustment wells in fault block oilfield can be determined, which has certain guiding significance for drilling and completion scheme design of adjustment wells.

2. Influence of water injection wells on formation pressure in fault block oilfields

In the actual production process, the water injection well has a great influence on the pressure of the adjustment well. Abnormal formation pressure is greatly affected by the induction of water injection wells, and the main types of induction are:

2.1. Vertical differentiation
Due to factors such as differences in physical properties such as the porosity and permeability of the oil layer, the advancement of injected water in each oil layer is different. There are differences in porosity and permeability in the longitudinal direction, resulting in different effects of water flooding. In the early stage of water flooding, the injected water would advance along the area with high permeability, and the pressure of high permeability layer would increase. However, in the area with low permeability, it is difficult to inject and exploit effectively, which would cause abnormal longitudinal pressure in high permeability area and low permeability area. In this way, a complex pressure system is formed in the same wellbore.

2.2. Horizontal heterogeneity of reservoir
Within the same sand layer, the porosity and permeability on the plane are not the same, the plane heterogeneity and the difference in the adaptation and control of the well to the existing layer, cause the uneven advancement of the injected water on the plane, causing the plane on the same layer the pressure at each well point is different. When the injection well is in the high-permeability zone, the injected water bursts along the high-permeability zone and bypasses the low-permeability zone, resulting in high water flooding in the high-permeability zone and poor development effect in the low-permeability zone. A large pressure gradient is formed on the belt.
2.3. Fault barrier
The fault acts as a barrier to the movement of fluid, which is equivalent to cutting the stratum space into two, cutting off the continuity of the stratum, and it would definitely affect the spatial distribution of fluid and pressure during the development process. When the injected water flows in the oil layer, it encounters the obstruction of the fault to form a high-pressure zone. The injected water can only change direction and flow along the fault. Therefore, the obstruction of the fault causes the injected water to push the mainstream part to form a high pressure, forming a large pressure gradient near the fault. However, the area blocked by the fault cannot be effectively replenished due to energy, forming a low-pressure area, and the negative pressure gradient of the fault increases.

2.4. Injection-production relation
Due to the well control degree, physical property conditions and perfect injection-production effects, pressure abnormalities can also be caused. For example, the difference in injection-production ratio in different layers due to the difference in injection volume would also lead to changes in the pressure difference between layers.

3. Prediction of maximum formation pressure of adjustment well
Before the adjustment well is drilled, in order to guide the drilling work, the longitudinal pressure profile to be drilled is extremely important. The adjustment well is located on the seepage flow line in the production well pattern. Between the water injection well (or production well) and the adjustment well, there is mainly the pressure generated by the gravity of the fluid and the pressure loss caused by the friction of the fluid flowing in the wellbore. Therefore, only the pressure loss between the water injection well (or production well) and the adjustment well position is required to obtain the pressure at the adjustment well.

![Figure 1. Schematic diagram of pressure calculation for adjustment well.](image)

In actual production, the formation pressure of the adjustment well in the fault block oil field is not only affected by the pressure of the surrounding water injection and production wells, but also by the fault. According to the theory of multi-well interference phenomenon, when there are multiple wells working at the same time in an actual oil field, the formation pressure at any point in the formation is required to be obtained by the principle of superposition. For the wells affected by the fault boundary, the problem can be transformed into a general problem through the mirror reaction method (Figure 1 and 2), and then the superposition theorem of potential.

According to the theory of seepage mechanics, the function of the fault is equivalent to the
impermeable boundary. The pressure distribution in the area near the fault is affected by the fault. The fluid can only flow along the fault and cannot pass through the fault. The fluid velocity along the normal direction of the fault is zero. A large pressure gradient is formed near the fault. So, the fault line is equivalent to a streamline in the flow field.

According to the mirror reaction method, the fault is used as a mirror, and the mirror image of a well of the same nature is reflected on the half plane on the other side of the mirror. For water injection wells, the same injection well is reflected on the other side of the fault mirror, causing a "pressure rise" to the formation, while production wells cause a "pressure drop". Therefore, the problem of fault boundary influence is reduced to the problem of two wells of the same nature working together in an infinite formation. According to the superposition theorem, the pressure in the area near the fault is formed by the superposition of the pressure generated by the two wells.

According to the idea of potential superposition, when there are n wells working simultaneously in an infinite stratum, the distribution of the potential for adjusting the position of the well can be expressed as:

\[ \Phi = \sum_{i=1}^{n} \frac{\pm q_{hi}}{2\pi} \ln r_i \]  

(1)

\( r_i \) is the distance from each well to the adjustment well position; \( q_{hi} \) is the production of average unit thickness wells, the positive value is used for production wells, and the negative value is used for injection wells; \( C \) is a constant determined by boundary conditions.

According to the relationship between potential and pressure, the formation pressure of adjusting well positions at different times can be expressed as:

\[ P_t = \int (q_{hi}, r_i, \overline{k_i}, \overline{S_{wi}}, t) \]  

(2)

Due to the interference between wells, the pressure at the position of the adjustment well is affected by many water injection wells or production wells around. Therefore, it is necessary to find the key well according to the connection relationship. This well has the greatest impact on the formation pressure of the adjustment well, and the maximum pressure would be formed at this position. This pressure is the maximum formation pressure of the adjustment well proposed by this method. In the fault block oilfield, abnormal high pressure and abnormal low-pressure area would be formed due to the blocking effect of faults. Under the same injection production relationship, the abnormal high-pressure area is often formed by the induction of water injection wells and the action of faults, while the abnormal low-pressure area...
is often formed by the action of production wells and faults. The following formula (3) can be used to calculate the pressure prediction that has a greater relationship with water injection wells.

According to the water injection parameters of the surrounding water injection wells, the formation physical parameters and the relationship with the fault, the maximum formation pressure of the adjustment well can be calculated.

\[ P_{\text{max}} = \max \left( P_{ij} + P_{hj} - P_{fj} - \Delta P_j \right) \]

\( j = 1, 2, \ldots, n \) (n is the number of water injection wells around the adjustment well position); \( P_{ij} \) is the injection pressure of the j water injection well, where \( P_{ij} = \rho gH \); \( P_{hj} \) is the static pressure of the wellbore liquid column of the j water injection well; \( P_{fj} \) is the static pressure of the wellbore liquid column of the j water injection well; \( \Delta P_j \) is the formation pressure drop existing between the position of the j injection well and the adjustment well; in the formula, \( H \) is the middle depth of the target formation of the adjustment well.

For the abnormally low-pressure area, there is no obvious injection well around it because of the fault. At this time, it is necessary to find out the well with the greatest influence on the formation pressure of the adjustment well position by the surrounding production wells. This pressure is the maximum formation pressure proposed by this method.

According to the production parameters of the surrounding production wells, the relationship with the fault and the physical parameters of the formation, the formation pressure can be calculated.

\[ P_{\text{max}} = \max \left( P_{pj} + P_{hj} + P_{fj} + \Delta P_j \right) \]

\( P_{pj} \) is the injection pressure of the j production well; \( P_{hj} \) is the static pressure of the wellbore liquid column of the j production well; \( P_{fj} \) is the static pressure of the wellbore liquid column of the j production well; \( \Delta P_j \) is the formation pressure drop between the adjustment well and the position of the j production well and the adjustment well.

4. Formation pressure loss between injection and production wells

The seepage pressure loss mainly refers to the pressure drop that exists between the water injection well or the production well and the adjustment well position due to the fluid flowing in the formation. At present, oilfields have been developed by water injection for a long time, and oil-water two-phase seepage is a very common phenomenon. Therefore, according to the superposition theorem, the pressure loss is directly derived from the mathematical model of oil-water two-phase seepage.

\[ \Delta P_j = \frac{1}{2\pi} \frac{q_h}{K_j} \ln \left( \frac{d_{1j} + d_{2j}}{r_{w2a_j}} \right) \]

\( q_h \) is the average fluid velocity per unit thickness; \( K_j \) is the weighted average permeability of the formation thickness of the j well; \( d_{1j}, d_{2j} \) is the distance from the adjustment well to the j well and the mirror reflection well; \( a_j \) is the distance from the j well to the fault.

5. Wellbore pressure loss

Wellbore pressure loss mainly includes vertical pipe damage and blast hole loss. Water injection well also includes nozzle loss.

\[ P_f = P_{f1} + P_{f2} + P_{f3} \]

Where \( P_{f1} \) is the vertical pipe pressure loss, \( P_{f2} \) is the nozzle pressure loss, and \( P_{f3} \) is the blast hole pressure loss.

5.1. Vertical pipe pressure loss

The resistance along the path is the cause of the pressure loss along the path. In this paper, the pressure loss along the path is the vertical pipe loss. According to fluid mechanics, the main formulas involved in calculating vertical pipe damage are as follows:

Average flow rate of fluid:
\[ v = \frac{Q}{A} \]  

(7)

\[ P_{f1} = \lambda \frac{L v^2}{D 2g} \]  

(8)

\( \lambda \), resistance coefficient along the way, dimensionless; \( L \), the distance from the bottom hole to the well head, m; \( D \), tubing diameter, m; \( v \), average velocity of fluid in the tubing.

The resistance coefficient along the way is related to the roughness of the closing and the flow rate, and the flow pattern is different, and the law of resistance and pipe loss along the way is different. Therefore, the drag coefficient in the formula \( \lambda \) is not a fixed number. Since the roughness is generally determined, it is generally determined based on the Reynolds number.

\[ Re = \frac{vd}{V} \]  

(9)

According to different Reynolds number ranges, Nicholas curve can be divided into five drag regions: laminar flow region (< 2320), critical region (2320 < 4000), smooth tube turbulent region (> 4000), transition region, rough tube turbulent region. For laminar flow, the drag coefficient along the way is only related to the Reynolds number, and has nothing to do with the tube wall roughness, that is, \( \lambda = \frac{64}{Re} \). For turbulent flow, due to the complexity of its flow, the determination of \( \lambda \) is mainly based on some empirical and semi-empirical formula Modi diagrams [16]. Combining with the actual situation of the oilfield, the resistance coefficient along the way under different injection rates of the oilfield is calculated as shown in Table 1.

| Injection Rate (m³/d) | \( \lambda \) |
|-----------------------|------------|
| <200                  | 0.03       |
| 200-400               | 0.025      |
| 400-500               | 0.02       |
| 500-600               | 0.013      |
| 600-800               | 0.009      |
| >800                  | 0.006      |

5.2. Borehole pressure loss

Borehole loss refers to the pressure drop of fluid flowing through the borehole. The loss of borehole is related to the velocity, density, diameter and number of holes. According to the empirical formula and oilfield data fitting, the calculation formula of borehole loss (\( \zeta \) is approximately taken as 1) is as follows:

\[ P_{f3} = \frac{3.57 \rho q^2}{N^2 d^4} \times 10^5 \]  

(10)

\( \rho \), density of fluid, kg/m³; \( d \), bore diameter, m; \( N \), number of holes.

5.3. Nozzle pressure loss

Nozzle loss is the pressure loss caused by the flow of injected water in the nozzle. The loss of the nozzle is related to the flow rate and the diameter of the nozzle. According to the experiment, the calculation formula of water nozzle is as follows:

\[ P_{f2} = 1.08 Q^2 D^{-3.8} \times 0.0981 \]  

(11)

\( Q \), daily water injection of well, m³/d; \( D \), nozzle diameter, m.

According to the data of water injection wells in the oilfield, the pressure loss of water nozzle under different displacement is obtained, as shown in Table 2.
Table 2. Pressure loss under different discharge capacity

| Flow (m³/d) | Pressure Loss (MPa) |
|------------|---------------------|
| ≤200       | 0.1                 |
| 200–300    | 0.3                 |
| 300–400    | 0.5                 |
| 500–600    | 1.0                 |

Taking a homogeneous fault block reservoir as an example, the planar homogeneous fault block reservoir has a permeability of 1000mD, a formation thickness of 10m, a crude oil viscosity of 60mPa·s, a constant production flow pressure of 8.5MPa, a well spacing of 500m, and a water injection well. The water injection rate is 300 m³/d, and there is a fault at a distance of 250m from the water injection well. In the fifth year of water flooding, the maximum pressure at the infill adjustment well calculated and predicted by this method is shown in Table 3.

Table 3. Maximum pressure (calculated value) of infill well in fault reservoir

| Infill Well | Injector | Well Distance from Fault (m) | Injection Rate (m³/d) | Bottom Hole Pressure (MPa) | Maximum Formation Pressure (MPa) |
|-------------|----------|------------------------------|-----------------------|---------------------------|----------------------------------|
| Inf1        | I1       | 250                          | 300                   | 18.82                     | 13.62                            |
|             | I2       | 1030                         | 300                   | 18.82                     | 13.53                            |
|             | I5       | 250                          | 300                   | 18.47                     | 12.25                            |
| Inf2        | I6       | 1030                         | 300                   | 18.48                     | 12.21                            |
|             | I7       | 750                          | 300                   | 17.46                     | 12.20                            |
| Inf3        | I1       | 560                          | 300                   | 18.82                     | 13.08                            |
|             | I2       | 560                          | 300                   | 18.82                     | 13.08                            |
|             | I5       | 560                          | 300                   | 18.23                     | 12.57                            |
|             | I6       | 560                          | 300                   | 18.23                     | 12.57                            |
|             | I7       | 790                          | 300                   | 17.20                     | 12.42                            |
|             | I8       | 790                          | 300                   | 18.20                     | 12.42                            |

The comparison between the estimated results and the numerical simulation results of the model is shown in Table 4. It can be seen that the error between the maximum adjustment well formation pressure estimated by this method and the numerical simulation result is less than 10%, which can be applied in the field, and this method can determine the greatest impact on the adjustment well position the injection well provides guidance for the next adjustment.

Taking Well D35ST02 in Penglai Oilfield as an example, Well D35ST02 encountered 10 oil layer groups from L10 to L100, and designed and produced oil groups L60-L100. The structure diagram of each oil layer is shown in Figure 3. There are faults developed around the adjustment well, and there are three water injection wells D50, D19 and M18 around it.

Table 4. Comparison of maximum pressure between calculated value and numerical simulation

| Infill Adjustment Well | Calculate the Maximum Formation Pressure (MPa) | Injector | Numerical Simulation Results (MPa) | Error (%) |
|------------------------|-----------------------------------------------|----------|-----------------------------------|-----------|
| Inf1                   | 13.62                                         | I1       | 14.1                              | 4.4       |
| Inf2                   | 12.25                                         | I5       | 14.2                              | -1.7      |
| Inf3                   | 13.08                                         | I1       | 14.5                              | 9.8       |
| Inf4                   | 12.57                                         | I5       | 12.22                             | 2.9       |
Predict the maximum pressure of each layer to be drilled in the adjustment well D35ST02. The prediction results are shown in Table 5. Offshore drilling uses positive pressure drilling. The density of the drilling fluid is generally about 1.15 g/cm$^3$ and the viscosity is about 15 mPa·s. According to the chart, it can be seen that when drilling into an abnormal pressure layer, drilling accidents may be caused due to abnormal pressure.

### Table 5. Formation maximum pressure prediction table

| Layer | Altitude (m) | Predict Pressure (MPa) | Normal Formation Pressure (MPa) | Formation Pressure Condition |
|-------|--------------|------------------------|-----------------------------|-----------------------------|
| L50   | -1097        | 14.39                  | 11.27                       | Overpressure                |
| L60   | -1142        | 12.24                  | 11.68                       | Overpressure                |
| L70   | -1184        | 12.40                  | 12.11                       | Overpressure                |
| L80   | -1229        | 13.08                  | 12.52                       | Overpressure                |
| L90   | -1291        | 12.83                  | 13.05                       | Under pressure              |
| L100  | -1333        | 13.19                  | 13.41                       | Under pressure              |

In order to ensure safe drilling, the abnormal pressure layer needs to be regulated. On the basis of pressure prediction, one or several key target wells that need to be drilled and controlled can be identified. The key target well generally refers to the well that has the greatest impact on the pressure at the drilling point of the adjustment well formation.

Taking layer L50 as an example, the parameters of water injection wells around Well D35ST02 are shown in Table 6. When D35ST02 has a vertical depth of 1097m in the L50 layer and a mud density of 1.15 g/cm$^3$, the hydrostatic column pressure at a depth of 1097m is 12.36 MPa. It can be seen that the maximum formation pressure of the D35ST02 well can reach 14.39 MPa, which requires injection of more than 12.5 MPa. Water wells are drilled off or controlled.
Table 6. D35ST02 Formation maximum pressure prediction table

| Well | Thickness (m) | Permeability (mD) | Injection Pressure (MPa) | Injection Rate (m³/d) | Bottom Hole Pressure (MPa) | Maximum Formation Pressure (MPa) |
|------|---------------|-------------------|--------------------------|-----------------------|--------------------------|---------------------------------|
| D50  | 160           | 18.5              | 2081                     | 5.96                  | 384                      | 15.96                           |
| D19  | 450           | 13.5              | 1287                     | 6.82                  | 406                      | 16.03                           |
| M18  | 480           | 16.9              | 4328                     | 7.01                  | 423                      | 15.24                           |

Based on the above conclusions, different adjustment measures have been taken for the abnormally high-pressure horizon and the abnormally low-pressure horizon, and good results have been achieved, ensuring the safety of drilling adjustment well D35ST02.

6. Conclusion
The paper establishes a method to predict formation pressure. This method based on related seepage theory and fluid mechanics theory could predict the maximum formation pressure of adjustment wells in complex fault block reservoirs by considering the influence of faults and surrounding injection-production wells.

The formation pressure of the fault block oilfield is greatly affected by the heterogeneity and the distribution of the faults. The error between the results calculated by the maximum formation pressure method of the adjustment well in the fault block oilfield and the numerical simulation calculation results is less than 10%. This method can determine the injection wells that need to be shut down during the drilling and completion of fault block reservoirs, and has certain guiding significance for the design of adjustment well drilling and completion programs.

Acknowledgments
The authors sincerely thank the national science and technology major project "Efficient Drilling and Completion and Supporting Technology Demonstration in Bohai Oilfield-Pressure Evaluation and Safety Control under Injection and Production Conditions of Penglai Oilfield Group" (Project No.: 2016ZX05058 -002-003) for the financial support of this work.

References
[1] Wang W T 2012 Evaluation of water flooding development effect of complex fault block reservoirs in Jiangsu Oilfield D. Southwest Petroleum University (In Chinese)
[2] Hu J S, Shao X J, Ma P H, Wang P, Shi L 2010 Development and adjustment practice in the middle and high water cut period of complex small fault block oilfields J. Fault Block Oil & Gas Field 17 (02) 202-205 (In Chinese)
[3] Zhang J, Zhang T Z, Chen P, Shi X B 2005 Formation pressure prediction method for adjustment wells based on seepage theory J. Drilling & Production Technology (03) 7-9+115 (In Chinese)
[4] Yao Y D, Li X F 2009 The combination of dynamic and static prediction and adjustment of well formation pressure J. Petroleum Drilling Technology 37 (04) 32-34 (In Chinese)
[5] Deli Jia, Zhao C J, Zhang S J, Zhao M X, Xu D K 2011 Research and Application of Synchronous Dynamic Test and Adjustment Technology for Novel Water Injection Well J. Applied Mechanics and Materials 1082 (44)
[6] Tian B 2019 Application of Fillippone Method in Predicting Pressure Coefficient of Block I J. Chemical Management (08) 211-212 (In Chinese)
[7] Qian L P, Wang X, Li F, Li J H, Wang J, Qu Y W 2018 Fillippone formula combined with equivalent medium theory to predict formation pressure J. Petroleum Geophysical Prospecting 53 (S2) 224-229+ 16 (In Chinese)
Kong L Y, Chen Z H, Zhen Y S 2019 Formation pressure prediction method and application in block 4 of the central Junggar Basin. *J. Henan Science* 37 (02) 248-254 (In Chinese)

Ma H 2012 Improvement and application of Fillippone formation pressure prediction method. *J. Petroleum Drilling Technology* 40 (06) 56-61 (In Chinese)

Zhang J C 2011 Pore pressure prediction from well logs: Methods, modifications, and new approaches. *J. Earth-Science Reviews* 108 (1)

El-Werr, A. Shebl, A. El-Rawy, N. Al-Gundor 2017 Pre-drill pore pressure prediction using seismic velocities for prospect areas at Beni Suef Oil Field, Western Desert, Egypt. *J. Journal of Petroleum Exploration and Production Technology* 7 (4)

Wang R H, Wang Z Z, Shan X, Qiu H, Li T Y 2013 Factors influencing pore-pressure prediction in complex carbonates based on effective medium theory. *J. Petroleum Science* 10 (04) 494-499

Liu J, Zhao G M, Wu Z H, Li J C 2017 Seismic Strain Energy Release of Active Faults in the Southeastern Margin of the Qinghai-Tibetan Plateau. *J. Earthquake Research in China* 31 (01) 90-106 (In Chinese)

Cao Y 2014 Abnormal High Formation Pressure Prediction and Causes Analysis. *Proceedings of 2014 3rd International Conference on Environment Energy and Biotechnology CBEES*: 5

Chen Z J 2015 The Improvement Methods of Pore Pressure Prediction Accuracy in the Central Canyon in Qiongdongnan Basin. *Proceedings of 2015 4th International Conference on Environment, Energy and Biotechnology CBEES*: 9

Chen L 2012 Fundamentals of Fluid Mechanics and Thermal Engineering. *M. Tsinghua University Press* (In Chinese)