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# Evaluation of Shale Gas Reservoir Characteristics and Parameter Analysis Based on Logging Data in Hunan Province

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**Abstract** Three-dimensional geological modeling of shale gas reservoirs can reveal the characteristics of reservoirs and physical parameters, which is of great significance for shale gas exploration and development. In this paper, the shale of Dalong Group in Lianyuan Depression in central Hunan Province is selected as the research object, and the ground level interpolation method is used to realize the three-dimensional geological modeling of shale gas reservoir, and the shallow shale gas reservoir in Lianyuan is compared with the typical shale gas reservoirs in central Hunan Depression, to summarize the characteristics of the shallow layer and analyze the developability. On this basis, the quantitative analysis method of physical properties of shale gas reservoirs was further optimized. The results show that the mineral composition and physical characteristics of the Dalong Formation at different depths are basically the same. The Dalong Formation in Lianyuan, Hunan Province, has high organic matter abundance and good organic matter type, belongs to the over-mature stage, has the physical characteristics of low porosity and low permeability, and its main gas-bearing type is adsorbed gas, and the brittleness of the reservoir and the geostress conditions are similar to those of the deeper layers, which indicates that the shallow Dalong Formation of Lianyuan has good exploitability, and it is a favorable direction for shale gas development. The results of this paper and the proposed evaluation grading standard can provide an important basis for the precise evaluation of shale reservoirs and the selection of favorable zones in Hunan Province.

**Index Terms** shale gas, reservoir characteristics, three-dimensional geologic modeling, physical properties parameters, ground level interpolation methods

## I. Introduction

As a clean energy source with broad prospects, shale gas is widely distributed in China. The exploration and development of shale gas is of great strategic significance to guarantee energy security, improve energy structure and help realize the dual-carbon goal [1], [2]. As a kind of unconventional oil and gas resources, shale gas has a special aggregation mechanism and various enrichment conditions, which makes a large number of mud shales that do not have conventional oil and gas formation conditions become directly meaningful for exploration again [3]-[5]. Although several mud shale formations have been developed in Hunan Province, with huge shale gas resource potential, which is a rare opportunity for the energy-poor Hunan Province, the special geological background of Hunan Province and the lagging technology are the difficulties faced by large-scale commercial development [6]-[8]. In order to be able to realize efficient exploitation, it is necessary to explore the development path based on geo-engineering integration [9]. Therefore, the establishment of quantitative three-dimensional geological modeling for the fine analysis of shale gas reservoirs, the portrayal of spatial distribution and the prediction of favorable zones of shale gas formations is conducive to deepening the geological understanding of shale gas reservoirs, which is particularly important for guiding the development of deep shale gas in the block [10]-[12]. Through the study of stratigraphic fine delineation and comparison, thickness change characteristics, logging fine interpretation, faults, levels and tectonic interpretation, the establishment of shale gas three-dimensional geologic model and the prediction of favorable reservoir distribution are completed, which will provide a strong theoretical support for the efficient exploration and development of deep-seated shale gas [13]-[16].

This paper takes the shale gas reservoir in the Lianyuan depression in central Hunan as the research object, based on the geological modeling technology, and uses the stratigraphic level interpolation method to carry out three-dimensional geological modeling. Then, from the dimensions of organic matter, mineral content, reservoir physical characteristics, pore structure, gas content, brittleness, and ground stress, the physical parameters of

Dalong Group shale in Lianyuan block were quantitatively compared with those of Dalong Group shale in other blocks of Xiangzhong depression, and the exploitability of shallow Dalong Group shale shale shale reservoir in Lianyuan was evaluated, and the evaluation methodology was optimized on the basis of the results of the evaluation.

## II. Three-dimensional geologic modeling of shale gas reservoirs in the Xiangzhong depression

In this paper, we take the Lianyuan Depression in central Hunan Province as a specific object to realize three-dimensional geological modeling and quantitative analysis of physical parameters of shale gas reservoirs in Hunan Province, China.

### *II. A. Overview of the study area*

The study area is located in the northern part of the Xiangzhong Pass. The Xiangzhong depression is a quasi-platform sedimentary depression developed from the metamorphic rock system of the Lower Paleozoic, which is characterized by the predominance of carbonate rocks of the Late Paleozoic I-Middle Triassic and clastic rocks, and belongs to the tectonic zone of South China, which is a depression basin superimposed on the southeast side of the Jiangnan-Xuefeng Tectonic Belt. The tectonic position of the Xiangzhong depression area is shown in Figure 1. The geotectonic position is located in the northern part of the South China Fold System and the southeast edge of the Xuefeng Rise, which mainly consists of five secondary tectonic units, namely, the Lianyuan Depression, the Longshan Bulge, the Shaoyang Depression, the Guandimiao Bulge, and the Zuling Depression.

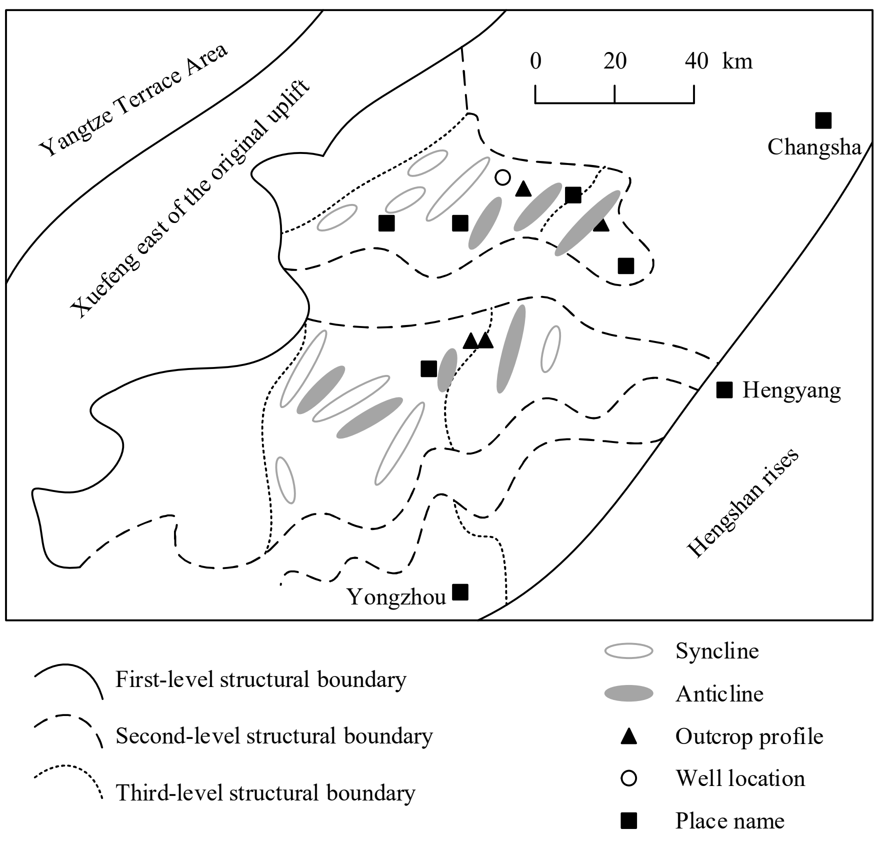


Figure 1: Regional structural position of Xiangzhong depression

### *II. B. Principles and Methods of 3D Geological Modeling*

Based on the preliminary basic geological research data and petrel modeling software with the best fine reservoir three-dimensional visualization technology, this study selects petrel 2018 modeling software, comprehensively applies the modeling principles of combining deterministic modeling and stochastic modeling, isochronous modeling and sedimentary phase control modeling, and selects sequential indicative simulation method for sedimentary phase modeling, and selects sequential Gaussian simulation method for reservoir parameter modeling [17].

### *II. C.Reservoir modeling*

In this study, the three-dimensional seismic, drilling and logging wells, and analytical data were collected from the Xiangzhong depression area, and the parameter model and fluid distribution model were established through the constraints of the phase-control model, which were combined with the simulation method of volumetric gas content in shale reservoirs to construct the storage calculation model.

#### II. C. 1) Reservoir Tectonic Modeling

Tectonic model is the foundation of 3D geological modeling, including the establishment of fault model, level model and 3D skeleton grid, in which 3D skeleton grid is the carrier of reservoir property distribution model and fluid distribution model. In the process of shale gas reservoir tectonic model construction, the dimension identification is the foundation. In this study, the construction of the facies model is mainly to identify the facies finely through the change characteristics of important parameters such as lithological color, TOC, and brittle mineral mass fraction between the effective and non-effective reservoirs, and at the same time, it is constrained by the logging and seismic attribute parameters at the macro level.

#### II. C. 2) Reservoir Phase Modeling

The phase models of reservoirs are divided into 2 categories: petrographic modeling and sedimentary modeling, which can quantitatively characterize the type, size, geometry, and three-dimensional spatial distribution of oil and gas reservoirs. The lithology of the effective reservoir section in the study area is generally black sandy and carbonaceous shale, with little variation in lithology, and the correspondence between lithology, physical properties, and gas content in the reservoir is not obvious, so the application of petrographic modeling to simulate the phase characteristics is constrained, and therefore, the present study uses sedimentary modeling to construct the reservoir phase characterization model.

The effective reservoir sedimentary subphase in the study area is the deep offshore shelf phase, with the upper sublayer being organic-rich siliceous mud microphase and the lower sublayer being organic-rich carbonaceous mud microphase. By comparing and analyzing the parameters of the sample points, it is found that the relative change rules among the four parameters of GR, TOC and Si, Ca mass fraction in the reservoir can indicate the changes of the depositional microenvironment. By analyzing the correspondence between each parameter and the sedimentary microphase of the reservoir sample points, the classification criteria of the sedimentary phase model were established as shown in Table 1.

Table 1: The classification criteria of sedimentary phase models

| Microphase category | Small layer phase category | Small layer code | *GR*/API | *TOC* /% | Si mass fraction /% | Ca mass fraction /% |
|---|---|---|---|---|---|---|
| Deep-water calcareous mud | Low organic matter phase mainly containing ash | X0 | <90 | <1.2 | <25 | >35 |
| Organic-rich biological calcareous sludge | High organic matter phase with high ash content | X1 | 320~360 | >3.5 | 25~40 | 18~35 |
| | Medium-organic phase with relatively high ash content | X2 | >360 | 2.7~3.5 | 35~45 | 12~18 |
| | Low organic matter phase with extremely low ash content | X3 | 150~320 | 2.2~2.7 | 55~65 | 3~6 |
| Organic-rich biological carbonaceous sludge | Low-organic phase mainly containing carbon | X4 | 320~360 | 1.8~2.7 | 50~60 | 6~12 |
| Organic-rich biological siliceous sludge | Low organic matter phase mainly containing silicon | X5 | <150 | <1.8 | >60 | <3 |

In the study, the spherical variogram function model is used to analyze the data and phase simulation for each small layer phase separately. Combined with the regional geological formation background, the phase parameters are determined, and finally the sequential indication stochastic simulation (SIS) method is used, and the simulation is superimposed for three realizations to obtain a more ideal sedimentary phase model.

#### II. C. 3) Modeling of reservoir properties

The parameter model of the reservoir reflects its change and distribution characteristics in three-dimensional space, which is divided into reservoir parameter model and fluid distribution model according to directly characterizing hydrocarbon properties or not. In this study, four important parameters of shale gas reservoir evaluation and development, namely density DEN, TOC, brittle mineral mass fraction and gas content, were selected to establish attribute models. All parameters are first coarsened by arithmetic method, and after Gaussian distribution transformation and variance function analysis, the reservoir parameter model and fluid distribution model are constructed by sequential Gaussian simulation method with robust algorithm, and the statistics of attribute parameter simulation methods are shown in Table 2.

Table 2: Statistics of attribute parameter simulation methods

| Parameters | Continuity | Constraint conditions | Model |
|---|---|---|---|
| DEN | Continuous | | Parameter model |
| TOC | Continuous | Phased control | Parameter model |
| Mass fraction of brittle minerals | Continuous | Phased control | Parameter model |
| Gas content | Continuous | Phased control | Fluid distribution model |

## III. Shale gas reservoir modeling and physical property parameter calculation methods

In this chapter, based on the three-dimensional geologic modeling of shale gas reservoirs using the bottom level difference method, the calculation method of physical parameters of shale gas reservoirs is explored.

### *III. A. Stratigraphic level interpolation methods*

Stratigraphic interfaces are the basis for delineating adjacent strata. The description of stratigraphic interface is generally expressed by irregular triangular network (TIN). However, in reality, the original sampling point data are sparse and unevenly distributed, and the direct use of irregular triangle mesh will make some triangles have particularly long sides, forming a “sick” triangle mesh. For this situation, this paper adopts the encrypted equilateral triangle mesh to generate virtual control point data. Compared with the irregular triangle mesh, the regular equilateral triangle mesh is the most ideal Delaunay triangle mesh, the triangles are equiangular and can be encrypted as needed. The encrypted point values are determined by the thin plate spline function, and the transition fitting phenomenon for the encrypted point values is solved by adding regularization terms to the thin plate spline function.

#### III. A. 1) Thin Plate Spline Functions

Thin plate spline function (TPS) is a very common interpolation method. It is generally based on 2D interpolation, which is also based on surface interpolation [18].

The TPS is able to generate a surface that passes through known control points and minimizes the change in slope of all slopes formed by the connection of all control points, i.e., it is based on generating surfaces of minimum curvature to fit these control points, i.e., the TPS method can fit a smoother surface based on sparsely discrete sampling points.

The approximate expression (1) for the thin plate spline function is shown below:

$$f(x,y)=a+a_x x+a_y y+\sum_{i=1}^{p} w_i d_i^2 \ln d_i ,(i=1,2,...,p) \tag{1}$$

where $x, y$ are the coordinates of the points to be interpolated, $d_i^2=(x-x_i)^2+(y-y_i)^2$, and $x_i$ and $y_i$ are the coordinates of the control point $i$. The thin-plate spline function consists of two parts: $a+a_x x+a_y y$ denotes the local trend function, whose expression is analogous to a first-order linear trend surface. The $d_i^2 lnd_i$ denotes the basis function, which aims at generating a surface of minimum curvature. The parametric coefficients $w_i, a, a_x$ and $a_y$ can be derived from the system of linear equations (2):

$$\begin{gathered} a+a_x x+a_y y+\sum_{i=1}^{p} w_i d_i^2 \ln d_i = f_i \\ \sum_{i=1}^{p} w_i = \sum_{i=1}^{p} w_i x_i = \sum_{i=1}^{p} w_i y_i = 0 \end{gathered} \tag{2}$$

where $p$ denotes the number of control points, $f_i$ denotes the known value of control point $i$, the estimation of the coefficients requires $p+3$ equations to form a system of linear equations, which are solved to obtain the values of the parameter coefficients.

Its matrix expression (3) is shown below:

$$\begin{pmatrix} K & P \\ P^T & O \end{pmatrix}\begin{pmatrix} w \\ a \end{pmatrix}=\begin{pmatrix} v \\ o \end{pmatrix}\begin{cases} K_{ij}=d_{ij}^2\ln d_{ij}, P_{pij}=\begin{pmatrix} 1 & x_1 & y_1 \\ 1 & x_2 & y_2 \\ 1 & \vdots & \vdots \\ 1 & x_p & y_p \end{pmatrix}, O_{3ij}=\begin{pmatrix} 0 & 0 & 0 \\ 0 & 0 & 0 \\ 0 & 0 & 0 \end{pmatrix} \\ V_{pij}=\begin{pmatrix} v_1 \\ v_2 \\ \vdots \\ v_p \end{pmatrix}, o_{3ij}=\begin{pmatrix} 0 \\ 0 \\ 0 \end{pmatrix}, w_{pij}=\begin{pmatrix} w_1 \\ w_2 \\ \vdots \\ w_p \end{pmatrix}, a_{3ij}=\begin{pmatrix} a \\ a_x \\ a_y \end{pmatrix} \end{cases} \tag{3}$$

The thin plate sample bending energy calculation formula (4) is shown below:

$$I_f = w^T K w \tag{4}$$

### III. A. 2) Regularized thin plate spline function

With raw discrete and sparse sample point data, this often leads to deviations in the fitting results, resulting in overfitting. The cause of overfitting of fitted curves and surfaces is that the irregular raw sample point data leads to an increase in the condition number of the interpolation matrix, which turns the interpolation problem into a pathological, or ill-posed, problem.

Regularization methods are an effective way to solve ill-posed problems. The basic idea of regularization methods for solving the ill-posed problem $Kx=y$ is to take the minimal element $x_a$ of the regularized generalized function $J_a(x)=\|Kx-y\|^2+a\|x\|^2$ as a regularized approximate solution of $Kx=y$, where $a$ is called the regularization parameter. The basic problem of the regularization method is to decide a strategy for choosing the regularization parameter a such that the minimal elements converge to the exact solution of the original problem $Kx=y$. Here the addition of a regularization parameter $a$ to $K_{ij}$ in Eq. (3) becomes Eq. (5):

$$\begin{cases} K_{ij}=d_{ij}^2\ln d_{ij}+I_{ij}\cdot\lambda^2\cdot a \\ \lambda=\dfrac{1}{p^2}\displaystyle\sum_{i=1}^{P}\sum_{j=1}^{P}d_{ij} \end{cases} \tag{5}$$

In this case the surface obtained by TPS does not pass through all the control points, avoiding the influence of noise at the control points and thus reducing the occurrence of overfitting results. If $a=0$ is normal TPS, if $a$ is infinity, TPS degenerates to least squares, when the bending energy is 0. Meanwhile, when the data of control points in a certain region is poor, if the surface obtained by TPS is made to pass strictly through the control points, the phenomenon of steep slopes will occur. This phenomenon can be avoided by adjusting the regularization parameters.

### III. A. 3) Regularized thin-plate spline function fitting stratigraphic levels

For the shale gas reservoir stratigraphy in the study area after subdividing, the upper and lower levels of each small layer will intersect with the shale gas drilling trajectory, and the sampling point data at the intersection points are used as the original control point data of the levels. It is not possible to express the stratigraphic levels only by relying on these small and unevenly distributed control point data, and it is necessary to encrypt some virtual points, which are obtained by spatial interpolation algorithm. In this paper, the encrypted points are adopted in the equilateral triangle mesh model generation algorithm, and the regularized thin plate spline function can calculate the values of these encrypted points through the sparse discrete and uneven original sampling points to construct a smooth spatial surface.

The stratigraphic level modeling is divided into structural modeling and attribute modeling, structural modeling refers to fitting the spatial shape of the surface, and attribute modeling refers to simulating the attribute values of the points on the surface. Since the horizontal range of the shale gas reservoir interface involved in this paper is much larger than the vertical range, the attribute simulation only needs to take into account the variation in the horizontal direction, i.e. the attribute simulation can be fitted by the regularized thin-plate spline function as well. The process of regularized thin plate spline function fitting the stratigraphic level is shown in Fig. 2, and the specific steps are as follows:

(1) Extract the original sampling points on the stratigraphic interface.

(2) Determine the gridding step size and generate grid nodes of encrypted points by gridding according to the distribution range of the original sampling points.

(3) Determine the parameters of the regular term, and substitute the original sampling point data into Eqs. (3)~(4) to find the parameter values of the regularized thin plate spline function.

(4) Find the value of the encrypted points according to the thin plate spline function, and find the error.

(5) If the accuracy and visualization effect meet the requirements, the fitting is finished. Otherwise, go back to step (3) and perform the calculation again until the accuracy meets the requirements.

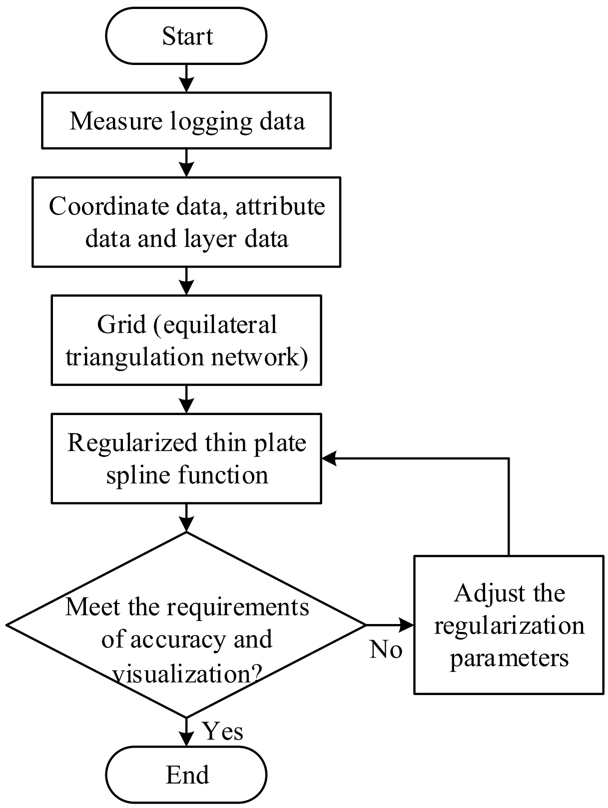


Figure 2: Flow chart of fitting the stratum interface

### *III. B. Calculation of physical properties parameters of shale reservoirs*

#### III. B. 1) Calculation of shale porosity

For shale reservoirs, which are characterized by many mineral components and poor porosity, in the process of solving the porosity value, firstly, combined with the regional lithological logging data, the complex components are divided into research. Shale reservoir rocks contain less pore volume, so there is usually less free movable water in the reservoir, so it can be seen that in the actual calculation, the value of water saturation is equal to the value of bound water saturation.

Based on the study of logging information, the multi-mineral model is used to solve the different logging response equations in conjunction with different input parameter values and different curve weights to improve the correlation between the different equations. The volumes of different minerals and fluids are finally determined, so as to accurately calculate the solved reservoir parameters. Their logging response equations are respectively:

$$\Delta T = \Phi \cdot [A \cdot (1 - S_{xo}) \cdot \Delta T_{hr} + S_{xo} \cdot \Delta T_{mf}] + V_{sh} \cdot \Delta T_{sh} + \sum_{i=1}^{n} V_{mai} \cdot \Delta T_{mai} \tag{6}$$

$$\Phi_n = \Phi \cdot [A \cdot (1 - S_{xo}) \cdot \Phi_{Nhr} + S_{xo} \cdot \Phi_{Nmf}] + V_{sh} \cdot \Phi_{Nsh} + \sum_{i=1}^{n} V_{mai} \cdot \Phi_{Nmai} \tag{7}$$

$$\rho = \Phi \cdot [A \cdot (1 - S_{xo}) \cdot \rho_{hr} + S_{xo} \cdot \rho_{mf}] + V_{sh} \cdot \rho_{sh} + \sum_{i=1}^{n} V_{mai} \cdot \rho_{mai} \tag{8}$$

$$\Phi + V_{sh} + \sum_{i=1}^{n} V_{mai} = 1 \tag{9}$$

where $\Delta T$ is the acoustic time difference curve. $\Phi_N$ is the neutron curve. $\rho$ is the density profile. $\Phi$ is the effective porosity. $S_{xo}$ denotes the residual gas saturation in the flushing zone. $V_{mai}$ denotes the mineral volume content. where the letter $hr$ denotes residual gas, the letter $mf$ denotes mixed fluid, the letter $sh$ denotes clay, and the letter $mai$ denotes rock skeleton.

Errors in any of the density curves:

$$\varepsilon_\rho^2 = \left[\frac{\rho - f_\rho}{U_\rho}\right]^2 (i = 1, nvol) \tag{10}$$

where $\varepsilon_\rho$ is the error in the density calculation. $f_\rho(v_i)$ is the predicted value of the density as a function of the formation volume. $U_\rho$ is the uncertainty value of the density.

Least square sum of errors for all equations:

$$\Delta^2 = \sum_{k=1}^{ntool} \varepsilon_k^2 \tag{11}$$

The optimal solution to the problem can be found using this method, and the resulting solution is the value of porosity when the correlation between the individual equations within the matrix is best.

#### III. B. 2) Water saturation of shales

This paper compares and analyzes several calculation methods, and finally determines that the Simandoux equation [19] is used to solve the water saturation of the reservoir in the shale gas reservoir in the study area with the following formula:

$$\frac{1}{R_t} = \frac{V_{sh}^c \cdot S_w}{R_{sh}} + \frac{\Phi^m \cdot S_w^n}{abR_w(1 - V_{sh})} \tag{12}$$

where $R_t$ is the formation resistivity, $V_s h$ is the clay content, $R_{sh}$ is the clay resistivity, $\Phi$ is the formation porosity, and $R_w$ is the formation water resistivity at formation conditions. $c = 1 - \frac{V_{cl}}{2}$, $V_{cl}$ is the clay content. $a, b, n, m$ denote lithology coefficient, lithology correlation coefficient, saturation index, and cementation index, respectively, which are constants.

The formula for calculating formation water resistivity under stratigraphic conditions is as follows:

$$R_w = R_{ws} \times (R_{wt} + X) / (F_{temp} + X) \tag{13}$$

$$X = 10^{(-0.34 \times \log(R_{mfs}) + 0.641)} \tag{14}$$

where $R_{mfs}$ is the mud filtrate resistivity. $R_{ws}$ is the surface formation water resistivity. $R_{wt}$ and $F_{temp}$ are the temperature and formation temperature at which the surface formation water resistivity is obtained from the well logging, respectively.

#### III. B. 3) Calculation of shale gas content parameters

The gas content of the shale reservoir is an important criterion for evaluating the shale gas reservoir, in the shale reservoir, the content of free gas depends on the size of the volume it occupies in the lower per ton of rock for the case of 1 atm, 298.15 K. It is also affected by the pressure and temperature of the formation, and also by the compression factor of the natural gas.

(1) Calculation of adsorbed gas content

a) Isothermal adsorption equation

Isothermal adsorption equation is the most commonly used method to calculate the adsorbed gas content of a substance, which is mostly applied to the calculation of adsorbed gas content in coal bed methane and shale gas layer. The isotherm is expressed as a constant temperature conditions, organic matter adsorbed on the surface of the casein and shale free of the relationship between the existence of an equilibrium state.

The formula for calculating the adsorbed gas volume for a fixed temperature and variable pressure:

$$V_a = \frac{(P \times V_L)}{(P + P_L)} \tag{15}$$

where: $V_a$ is the adsorbed gas content, $P$ is the reservoir pressure, $V_L$ is the Langmuir volume, and $P_L$ is the Langmuir pressure.

b) Determination of key parameters and theoretical correction methods

Since the experiment must be carried out at a certain temperature and the total organic carbon content of the samples used is a constant value in order to obtain the experimental results. Before the calculation process of the experiments in the case of different depths can begin, TOC and temperature corrections must first be carried out for the parameters used in the experiments, which are crucial for studying the adsorption properties of shale reservoirs at various depths. Therefore, the corresponding parameters need to be precisely adjusted according to this information in order to obtain the best results. The equations are as follows:

$$V_{lt} = 10^{(-c_1 \cdot T + c_2)} \tag{16}$$

$$P_{lt} = 10^{(c_3 \cdot T + c_4)} \tag{17}$$

$$c_2 = \log V_l + (c_1 \cdot T_i) \tag{18}$$

$$c_4 = \log P_l + (-c_3 \cdot T_i) \tag{19}$$

where $V_{lt}$, $P_{lt}$ are the Langmuir volume and pressure at reservoir temperature, respectively. $T$ is the reservoir temperature, $T_i$ is the temperature of the isotherm.

The total organic carbon content correction is given by:

$$V_{lc} = V_{lt} \cdot \frac{TOC_{\log}}{TOC_{iso}} \tag{20}$$

where $V_{lc}$ is the Langmuir volume corrected for temperature and TOC, $TOC_{iso}$ is the total organic carbon (TOC) content of the shale used in the isothermal adsorption experiments, and $TOC_{\log}$ is the total organic carbon (TOC) value obtained from the well logging.

The adsorption gas content was calculated using the formula:

$$G_a = \frac{V_{lc} p}{(p + P_{lt})} \tag{21}$$

where $G_a$ is the adsorbed gas content, $p$ is the reservoir pressure, and $P_{lt}$ is the Langmuir pressure at reservoir temperature.

(2) Calculation of free gas content

The formula for calculating the free gas content under stratigraphic conditions is:

$$Q_f = \frac{\varphi \times S_g}{Den} \tag{22}$$

where $Q_f$ is the free gas content at reservoir temperature-pressure conditions, $\varphi$ is the porosity, $S_g$ is the gas saturation, and $Den$ is the formation bulk density.

**III. B. 4) Shale Ground Stress Calculations**

(1) Minimum horizontal principal stress calculation

In unconventional oil and gas reservoirs, the minimum horizontal principal stress (MHPS) is a key factor in determining the fracturing design, controlling the fracture expansion and evaluating the fracturing effect, and it is the basis for the subsequent calculations of compressibility. The MHPS is the smallest stress that needs to be overcome in the fracturing modification, and its magnitude reflects the degree of difficulty in the fracturing of the fracture initiation. As the minimum horizontal principal stress becomes smaller, the fracture initiation pressure of the rock formation will be gradually reduced, and it will be easier to produce cracks and better compressibility.

The formula for calculating the minimum horizontal principal stress is as follows:

$$\sigma_h = \frac{E_h}{E_v} \times \frac{v_v}{1-v_h}(\sigma_v - \alpha \times \sigma_p) + \frac{E_h}{1-v_h^2} \times \varepsilon_h + \frac{E_h \times v_h}{1-v_h^2} \times \varepsilon_H + \alpha \times \sigma_p \tag{23}$$

where: $\sigma_h$ is the minimum horizontal principal stress. $E_h, E_v$ denote the Young's modulus in the anisotropic horizontal and vertical directions, in that order. $v_h, v_v$ denote the Poisson's ratio in the anisotropic horizontal and vertical directions, in that order. $\alpha$ is the effective pressure coefficient. $\sigma_p$ is the formation pore pressure. $\varepsilon_h, \varepsilon_H$ are the minimum and maximum tectonic pressure coefficients, respectively.

(2) Horizontal principal stress difference calculation

The emergence of fracture network in the reservoir, in addition to the brittleness of the rock itself and the original natural fractures have an influence on it, is also related to the influence of the reservoir ground stress to a certain extent. In the actual construction of fracturing operation, the height of cracks is expanded along the direction of the maximum horizontal principal stress, which indicates that when the horizontal stress difference is smaller, it is beneficial to the formation of complex crack networks, and the compressibility is better.

Horizontal principal stress difference is the difference between the maximum and minimum stress values of the rock when it is subjected to external forces, which is crucial for the formation of crack networks.

The formula for calculating the horizontal principal stress difference is as follows:

$$Y = \sigma_H - \sigma_h \tag{24}$$

where: $Y$ is the horizontal principal stress difference. $\sigma_H, \sigma_h$ are the maximum and minimum horizontal principal stresses, respectively.

## IV. Analysis of the developability of shale gas reservoirs based on physical parameters

Developability of shale gas reservoirs refers to the properties of shale gas reservoirs with superior organic matter characteristics, mineral content characteristics, reservoir physical characteristics, pore structure characteristics, gas-bearing characteristics, brittleness characteristics, and geostress characteristics, which can be developed through reservoir modification. This chapter summarizes the quantitative analysis method of shale gas reservoir physical properties by evaluating the developability of shale gas reservoirs in the Lianyuan depression in central Hunan.

### *IV. A. Comparison of Geological Parameters of Shale Gas Reservoirs*

The difference in mineral content is the prerequisite for the difference in reservoir structure. Through researching related studies on shale gas reservoirs, 10 samples from two wells in the Dalong Formation of the Lianyuan Depression in central Hunan were selected for comparison with the research data in terms of mineral content, and the results of the mineral content comparison of shale gas reservoirs of the Dalong Formation in different areas are shown in Figure 3. Among them, the siliceous mineral content in Lianyuan area ranges from 39.2% to 65.5%, with an average of 53.4%, while the range of siliceous mineral content in the areas of Xinshao, Longhui, Anhua, and Xinhua is from 39.6% to 71.9%, 38.6% to 56.4%, 42.9% to 72.8%, and 44.9% to 61.2%, with the corresponding averages of 53.8%, 50.4%, 50.7%, and 54.5%, respectively, 58.7%, 54.5%, Xupu area research available information is less, only the average value of 51.0%. 6 areas of siliceous mineral content in the average of 50% ~ 60%, the content is more consistent. The calcium minerals with the same brittleness characteristics also have the same content, of which Lianyuan, Xinshao, Longhui, Anhua, Xinhua, Xupu areas are 18.6%, 17.3%, 8.2%, 9.4%, 15.5%, 10.7%, the average value of calcium minerals is less than 20%, and most of them are concentrated in about 10%. Different areas of the Xiangzhong depression have different burial depths, but the mineral contents of the Dalong Formation have strong similarities, especially the high siliceous mineral contents.

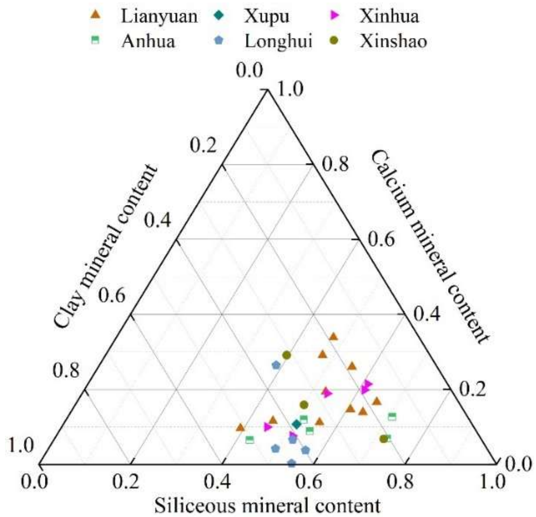


Figure 3: triangular chart comparing the mineral content of deep and shallow layers

Comparison of shale gas reservoir parameters in different areas of Xiangzhong depression is shown in Table 3. Combined with Figure 3, it can be seen that the similar mineral content also reflects the similar lithology. The lithology of the deep shale reservoirs in the shallow Lianyuan, Xupu, and Xinshao areas and the deep Lunghui, Anhua, and Xinhua areas is also similar, with all of them being black gray siliceous shale or siliceous shale, and the sedimentary phases are all in front of the delta or in front of the edge of the delta, and the different tectonic positions of different areas lead to some degree of differences in sedimentation phases, but in general the sedimentary environment and material composition of the Dalong Group in different areas are basically the same. Different areas are located in different tectonic positions, resulting in differences in their sedimentary phases to a certain extent, but in general, the depositional environments and material compositions of the Dalong Formation are basically the same in different areas.

Table 3: Comparison of shale gas reservoir parameters in different areas

| Block | Rock type | Sedimentary phase | Burial depth /m | Porosity /% | Permeability /×$10^{-5}$ μ$m^2$ |
|---|---|---|---|---|---|
| Xinshao | Black siliceous and clayey shale | Delta Frontier - Transition zone between coastal and shallow seas | 1500~3100 | 4.81~7.52 | 0.0122~0.5204 |
| Longhui | Black gray-bearing siliceous shale and clay shale | The leading edge of the delta- Transition zone between coastal and shallow seas | 2540~2850 | 2.32~10.45 | 0.0151~0.4730 |
| Anhua | Siliceous shale, clay shale and silty shale | The Chao Ping complex environment at the forefront of the delta | 1870~3615 | 2.93~3.44 | 0.0184~0.5659 |
| Xinhua | Black carbonaceous shale, siliceous shale, mudstone, silt-sand mudstone | The transition zone between the former delta and the deep-sea shelf | 2045~4200 | 4.62~6.08 | 0.0715~0.4890 |
| Xupu | Siliceous shale, clay, silty mudstone | A shallow continental shelf in the former delta | 1224~2845 | 3.50~4.52 | 0.0163~9.6315 |
| Lianyuan | Fine-grained mixed rock, siliceous shale | Delta Frontier - Pre-Delta | 1060~2538 | 1.45~4.94 | 0.0056~0.1448 |

Comparison of porosity and permeability in different areas are shown in Figures 4 and 5, respectively. The average porosity of the shale gas reservoir of Dalong Formation in Lianyuan area is 3.28%, which is similar to the porosity values of five areas, including Xinshao, Longhui and Anhua, indicating that the reservoir in Lianyuan area preserves pore space of comparable scale with that of deeper shale gas reservoirs, even though the reservoirs are shallowly buried and at atmospheric pressure. The permeability of the reservoir in Lianyuan area is 0.0078 mD on average, which is basically the same as that in Xinshao, Longhui, Anhua, Xinhua and other areas, but the permeability in Xupu area is slightly higher, and the physical characteristics of the shallow shale gas reservoirs of Dalong Formation are basically the same in different areas in general.

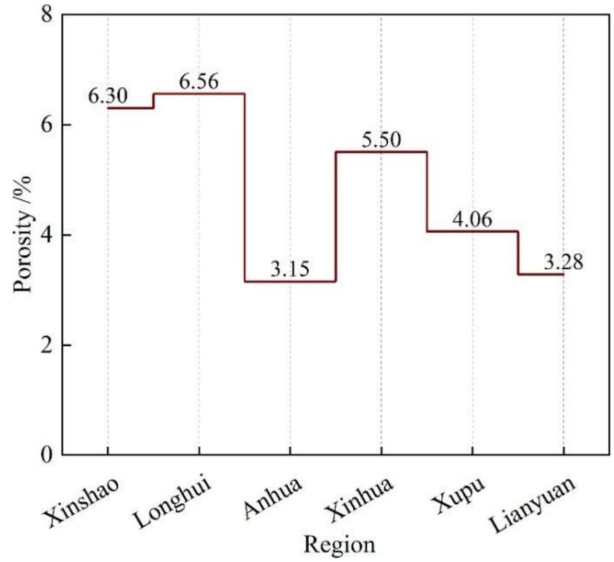


Figure 4: Porosity comparison

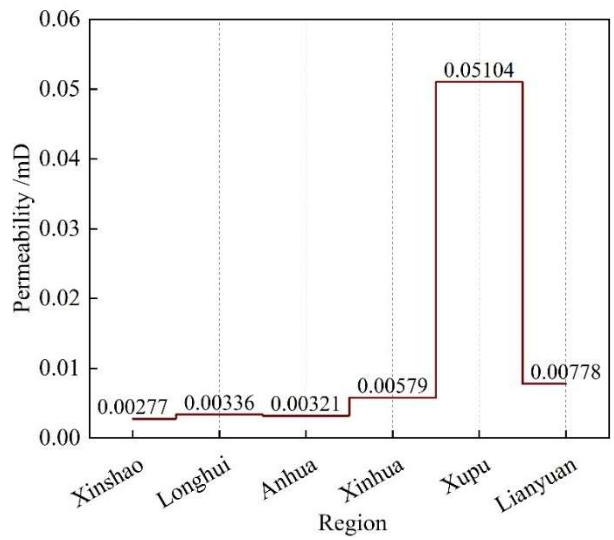


Figure 5: Penetration rate comparison

Comparison of organic matter parameters of shale gas reservoirs in different areas of Xiangzhong depression is shown in Table 4. Research data and experimental data show that the average TOC of Dalong Formation in Lianyuan area is 4.35%, and the average value of TOC in five areas, such as Xinshao, Longhui, Anhua, etc., is more than 3.2%, and the types of organic matter are all type I or II, which reflect that the Dalong Formation is rich in organic matter and has large potential for anger, and it is a high-quality shale gas reservoir. However, the stratigraphic pressure of Dalong Formation in Lianyuan area is normal pressure, and the gas content is 0.40~1.00m3-t-1, which is lower than that of Xinshao, Longhui, Anhua and other areas.

***IV. B. Comparison of Rock Mechanical Properties and Ground Stresses***

In this section, siliceous mineral content, Poisson's ratio, modulus of elasticity, and horizontal principal stress difference, which are customarily used in the evaluation criteria of engineering desserts, are selected for comparative analysis. The comparison results of rock mechanical parameters and horizontal principal stress difference in different regions are shown in Table 5.

The statistical results show that the siliceous mineral content of Lianyuan area is 46.8%, which is similar to that of Xinshao, Anhua and Xupu blocks, except for Longhui area, the siliceous mineral content of deep and shallow Dalong Formation is more than 45%, and the brittleness of the rock is good. Poisson's ratio in Lianyuan area is 0.24, and Poisson's ratio in deep reservoirs in the rest of the area is about 0.20. The modulus of elasticity of the shallow Dalong Formation in Lianyuan area is 31.8 GPa, which even exceeds that of Xinshao and Longhui areas, indicating that the shallow reservoir has better brittleness and is more prone to form cracks. The horizontal principal stress difference in Lianyuan area is 16.7MPa, which is basically consistent with the stress environment of deep shale gas reservoirs in Xiangzhong depression. Comprehensive comparison shows that the brittleness of the shallow shale gas reservoir in Dalong Formation in Lianyuan area is basically the same as that of the deep reservoir, even better than that in some areas, and the stress environment is basically the same, so it can be borrowed from the experience of deep shale gas fracturing and exploitation, and it is a favorable shale gas exploitation layer from the engineering point of view.

Table 4: Comparison of organic matter parameters in shale gas reservoirs in different areas

| Block | Organic matter parameters | | | Gas-containing parameters | | Pressure characteristics |
|---|---|---|---|---|---|---|
| | Organic matter abundance /% | Organic matter type | Organic matter maturity /% | Main gas-containing types | Gas content /$m^3 \cdot t^{-1}$ | |
| Xinshao | 2.60~3.30 | Ⅰ$_1$, Ⅱ$_1$ | 2.04~2.55 | Free gas, adsorbed gas | 6.6~8.2 | Overpressure |
| Longhui | 1.22~7.94 | Ⅰ$_1$, Ⅱ$_1$ | 1.45~2.72 | Free gas, adsorbed gas | 6.2~7.7 | Overpressure |
| Anhua | 2.94~3.42 | Ⅰ$_1$, Ⅱ$_1$ | 2.30~2.52 | Free gas, adsorbed gas | 1.2~8.1 | Overpressure |
| Xinhua | 1.95~3.76 | Ⅰ$_1$, Ⅱ$_1$ | 2.15~2.68 | Free gas, adsorbed gas | 2.4~4.8 | Overpressure |
| Xupu | 3.07~3.63 | Ⅰ | 2.24~3.25 | Free gas, adsorbed gas | - | Overpressure |
| Lianyuan | 1.25~7.80 | Ⅰ$_1$, Ⅱ$_1$ | 2.40~3.65 | Adsorbed gas | 0.40~1.00 | Atmospheric pressure |

Table 5: Comparison of rock mechanical parameters

| Block | Siliceous minerals /% | Poisson's ratio | Elastic modulus /GPa | Horizontal principal stress difference /MPa |
|---|---|---|---|---|
| Xinshao | 48.5 | 0.25 | 25.6 | 14.4 |
| Longhui | 40.2 | 0.22 | 26.7 | 17.3 |
| Anhua | 51.6 | 0.20 | 36.4 | 21.2 |
| Xinhua | 62.4 | 0.22 | 31.2 | 25.4 |
| Xupu | 44.3 | 0.24 | 42.6 | 11.5 |
| Lianyuan | 46.8 | 0.24 | 31.8 | 16.7 |

### *IV. C. Evaluation of total organic carbon content*

Total Organic Carbon (TOC) is one of the important parameters for evaluating shale gas reservoirs. It is regarded as the most critical "geological sweet spot" in shale, which can reflect the hydrocarbon generation capacity and gas content of the reservoir. The relationship between shale TOC and gas content is shown in Figure 6. Higher TOC values indicate that the effective source rock has stronger hydrocarbon potential, which also means that there may be more free and adsorbed gas in the cracks of the shale gas reservoir. Related studies have shown that the TOC of commercially valuable shale gas reservoirs is usually in the range of 2%-10%.

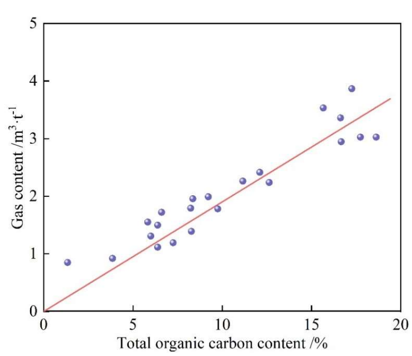


Figure 6: Relationship between total organic carbon content and gas content in shale

In practical applications, commonly used analytical methods include thermogravimetric analysis (TGA), elemental analysis, and ultraviolet absorption. Among them, thermogravimetric analysis is a commonly used, high-precision analytical method that can be used to determine the organic matter content and organic matter type in samples, which is based on the heating of the sample at a constant temperature and the measurement of the weight loss rate of the sample, so as to determine the organic matter content in the sample. The TOC grading evaluation criteria for Chinese terrestrial shales are shown in Table 6, taking into account the differences in their contents in different regions and categorizing them into two types based on the lake basin environment in which they were formed.

Table 6: TOC classification evaluation criteria

| Grading standard | Salted lake basin *TOC* /% | Freshwater lake basin *TOC* /% |
|---|---|---|
| Very high | ≥4.5 | ≥6.4 |
| High | 2.4≤TOC<4.5 | 4.5≤TOC<6.4 |
| Medium | 1.2≤TOC<2.4 | 2.4≤TOC<4.5 |
| Low | <1.2 | <2.4 |

### *IV. D. Evaluation of reservoir physical properties*

By analyzing the physical properties of shale such as porosity, permeability and gas saturation, the size of the gas storage capacity of the shale gas reservoir can be evaluated.

#### IV. D. 1) Shale porosity

Porosity is one of the important parameters for evaluating oil and gas reservoirs, which is important for determining the rock reservoir space, fluid saturation, and oil and gas geological reserves. There are two main measurement and analysis methods for determining the porosity of shale gas reservoirs in the laboratory: the GRI method and the GB/T 29172-2012 core analysis method. In this paper, the effects of sample drying temperature, crushed particle size, sample oil washing, saturation pressure and equilibrium time on shale porosity measurement results are discussed, and the corresponding optimal test conditions are given.

The commonly used logging methods for evaluating shale porosity include water absorption method, natural gamma radiation logging (NGR) method, nuclear magnetic resonance logging (NMR) method, and porosity logging method. Among them, the water absorption method is one of the simplest and most commonly used methods. It evaluates porosity by adding water to the formation pores and measuring the change in reservoir saturation. The natural gamma radiation logging method and the nuclear magnetic resonance logging method are based on the relationship between porosity and features such as rock element content and nuclear magnetic resonance parameters in the formation, and evaluate porosity by measuring the gamma ray and nuclear magnetic resonance signals in the formation. The porosity logging method, on the other hand, utilizes physical parameters such as acoustic velocity and density to calculate the porosity value. All these methods can be measured directly in the well to provide real-time data in the field, which is of great significance for oil and gas exploration and development.

In addition, the NMR T2 spectra of shale under different echo spacing time conditions are shown in Figure 7. Since the shale formation mainly has nanopores, its T2 relaxation time is very short. Therefore, it cannot be measured accurately, resulting in the NMR measured porosity being smaller than the actual total porosity of the formation.

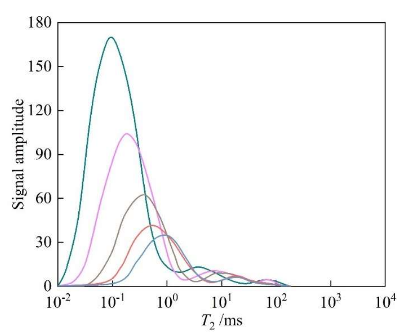


Figure 7: $T_2$ spectra of shale nuclear magnetic resonance under different echo interval times

In this paper, the shale gas reservoir grading evaluation criteria based on the total porosity are proposed by the statistics of the total porosity of different depression land-phase shales in China as shown in Table 7.

Table 7: Grading evaluation criteria for total porosity of shale gas reservoirs

| Classification | Total porosity /% |
|---|---|
| Class Ⅰ | ≥6.4 |
| Class Ⅱ | 4.5≤TOC<6.4 |
| Class Ⅲ | 2.4≤TOC<4.5 |
| Class Ⅳ | <2.4 |

Shale gas reservoirs have strong sensitivity, therefore, the current characterization methods for shale pore structure, except for logging methods which are closer to the original conditions of the formation, other indoor characterization methods are affected by stress release, mineral dehydration and other disturbing factors caused by changes in temperature, pressure and fluid properties in the non-in-situ state, and it is difficult to accurately reflect the characteristics of the reservoirs under its in-situ conditions.

#### IV. D. 2) Shale permeability

Currently, the main laboratory methods for determining shale permeability include the steady state method and the unsteady state method. The steady state method utilizes Darcy's law to calculate the permeability by measuring the differential pressure and flow rate when the tested fluid flow reaches a steady state. The advantages are high stability of the measurement results, high accuracy of the data, the use of $N_2$ or $CO_2$ as the measurement medium, which will not cause environmental pollution, the disadvantage is that the measurement time is relatively long, usually need 6~24h.

Non-stationary methods include mercury pressure method, gas desorption method, hydraulic burst method and transient method. Among them, the piezomercury method is a commonly used method to determine the porosity and permeability of reservoirs in unconventional oil and gas reservoirs. The method utilizes a mercuric pressure instrument to determine the porosity and permeability of a reservoir sample by applying different pressures to it. When the pressure applied is higher, the mercury column contained in the pores will be smaller, so as to calculate the reservoir porosity, permeability and other physical parameters. The gas desorption method can be used to determine the adsorption capacity and permeability of the reservoir by desorbing the reservoir sample in situ. The adsorption capacity and permeability of the reservoir can be obtained by measuring the relationship between the amount of natural gas released from the reservoir sample at different pressures and the pressure. The hydraulic bursting method is a method of determining the permeability by using water pressure to pressurize the reservoir sample to the rupture point. This method requires on-site sampling and a high level of technical requirements. The transient method is a method for determining permeability based on the theory of transient perfusion. This method calculates the permeability of a reservoir by measuring the pressure decay curve of a reservoir sample under transient perfusion conditions. Each of these non-stationary methods has advantages and disadvantages, and should be selected according to the actual situation in specific applications.

#### IV. D. 3) Gas Saturation

The traditional saturation evaluation method uses electrical logging and relies mainly on the Archie model. It was found that the amount of dissolved shale gas is mainly affected by factors such as pressure, temperature, mineralization and the amount of residual oil in the shale. Although the dissolved shale gas content is very small, the influence of these factors should be taken into account during the simulation study. This paper discusses the characteristics of shallow shale gas reservoirs in Lianyuan block, Xiangzhong depression area, and proposes a method to fit the gas saturation by transverse and longitudinal wave time difference ratio and DEN as well as to calculate the gas saturation based on TOC, which is a better way to calculate the gas saturation of low-resistance shale gas reservoirs, and is not limited by the variability of the reservoirs in the area.

## V. Conclusion

In this paper, the shallow Dalong Formation in Lianyuan was selected as the specific research object, and the physical parameters were quantitatively analyzed on the basis of three-dimensional geological modeling to explore the developability of shale gas reservoirs in the central depression area of Hunan Province, China.

The average values of siliceous mineral contents of Dalong Formation shale in Lianyuan area and Xinshao, Longhui, Anhua, Xinhua, Xupu, and other Xiangzhong depression areas are 53.4%, 53.8%, 50.4%, 58.7%, 54.5%, and 51.0% for siliceous minerals, and 18.6%, 17.3%, 8.2%, 9.4%, 15.5%, and 10.7% for calcareous minerals respectively. The mineral contents of the six areas are relatively consistent, indicating that the mineral contents of the Dalong Formation have strong similarity, especially the siliceous mineral content is higher. In terms of rock mechanical properties and stress, Poisson's ratio, modulus of elasticity, and horizontal principal stress difference in

Lianyuan area are 0.24, 31.8 GPa, and 16.7 MPa, respectively, which are basically consistent with the stress environment of deep shale gas reservoirs in Xiangzhong depression. This shows that the brittleness of the shallow shale gas reservoir in Dalong Formation in Lianyuan area is basically the same as that of the deep reservoir, even better than that in some areas, and the stress environment is also basically the same, which can be borrowed from the experience of deep shale gas fracturing and exploitation, and it is a favorable shale gas exploitation layer under the engineering point of view.

In addition, this paper analyzes the main parameters of shale gas reservoir evaluation and carries out the preference, and determines the classification evaluation indexes of shale gas reservoirs, including total organic carbon content (TOC), porosity, permeability and gas saturation degree of several factors.

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