

Article

Permeability Upscaling Conversion Based on Reservoir Classification

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Abstract: Deep and ultra-deep reservoirs are characterized by low porosity and permeability, pronounced heterogeneity, and complex pore structures, complicating permeability evaluations. Permeability, directly influencing the fluid production capacity of reservoirs, is a key parameter in comprehensive reservoir assessments. In the X Depression, low-porosity and low-permeability formations present highly discrete and variable core data points for porosity and permeability, rendering single-variable regression models ineffective. Consequently, accurately representing permeability in heterogeneous reservoirs proves challenging. In the following study, lithological and physical property data are integrated with mercury injection data to analyze pore structure types. The formation flow zone index (FZI) is utilized to differentiate reservoir types, and permeability is calculated based on core porosity–permeability relationships from logging data for each flow unit. Subsequently, the average permeability for each flow unit is computed according to reservoir classification, followed by a weighted average according to effective thickness. This approach transforms logging permeability into drill stem test permeability. Unlike traditional point-by-point averaging methods, this approach incorporates reservoir thickness and heterogeneity, making it more suitable for complex reservoir environments and resulting in more reasonable conversion outcomes.

Keywords: logging evaluation; low porosity and low permeability; flow zone index; permeability



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1. Introduction

Unconventional resources represent a significant field of exploration and development, globally. Research conducted over the past two decades indicates that unconventional oil and gas reservoirs have become one of the primary areas of focus [1]. Among these, the X Depression is a low-permeability tight reservoir with a complex pore structure, where clastic particle sizes vary significantly, the oil–water relationship is highly intricate, and permeability exhibits severe heterogeneity in both horizontal and vertical directions, resulting in a broad range of permeability variations within the same test interval [2,3]. Nevertheless, permeability is a key parameter for describing reservoirs and their oil and gas production capacities. During the mining process, areal variation in properties, such as permeability, porosity, thickness, and sand continuity, impacts both oil recovery and its distribution within the field [4,5]. In addition to calculating permeability, the scale conversion of permeability is also of significant importance. Under the constraint of cost-saving, it provides essential parameters for productivity prediction.

At present, core permeability is primarily determined through laboratory core analysis. Absolute permeability can be determined via logging methods, the effective permeability of the test layer can be determined using a drill stem test (DST), and the single-point effective permeability of the reservoir can be measured using modular dynamics testers (MDTs). Among these methods, the use of logging data for permeability calculation represents one of the key, most efficient approaches for evaluating reservoir permeability. This method is convenient and rapid and provides continuous depth measurements, resulting in its

widespread application in oil fields [6]. DSTs measure reservoir permeability parameters through fluid sampling and pressure testing, yielding accurate results that can reliably predict production capacity. However, DST operations are challenging, costly, and limited to a few testable layers, complicating the evaluation of untested layers and affecting the assessment of gas fields. Therefore, the use of alternative methods to replace the use of DST permeability is of particular importance.

A number of methods have been proposed by scholars both domestically and internationally to study scale conversion, primarily using the explicit solution of network equations to accurately establish permeability. However, grid-block permeability may be strongly influenced by the boundary conditions imposed on the flow equations and the size of the grid blocks [7–9]. Furthermore, Sharifi M et al. define the objective function as the difference in the propagation time between fine-scale and coarse-scale models. By minimizing the objective function, the permeability of the upscaled model is calculated [10]. Germanou L. et al. propose upscaling from the pore scale [11]. Some Chinese scholars have focused on scale conversion based on the mobility of pressure measurement [12,13]. For example, Yang et al. determined dynamic permeability by measuring mobility from pressure measurement [14], and Shi et al. established a conversion model by reprocessing the pressure measurement data and considering reservoir pollution [15]. Permeability averaging methods primarily include point-by-point arithmetic averaging, weighted averaging, and harmonic averaging. However, methods based on flow unit classification (which involves calculating the average permeability for reservoirs of the same type and subsequently converting this figure to the average permeability for larger strata, thereby achieving scale conversion through permeability averaging methods) have not been observed.

Based on the above information, in the study presented herein, we focused on the deep and ultra-deep blocks of the X Depression. We propose a classification of reservoirs based on different pore structures and employ the FZI theory to establish corresponding permeability calculation models. Subsequently, the reservoirs under study are divided into several flow units, and the average permeability for each unit is calculated separately. Effective thickness-weighted averaging is then used to perform the upscaling conversion of test layer permeability, offering a more reasonable approach compared to traditional point-by-point averaging methods. This method provides accurate and reliable reservoir flow parameters for reservoir evaluation and production forecasting, facilitating improved reservoir description and dynamic simulation for oil and gas fields.

2. Characteristics of Sandy Conglomerate Reservoirs

Deep, ultra-deep, and unconventional reservoirs increasingly represent key areas of oil and gas exploration and development, with more stringent standards for logging permeability accuracy. In China, according to the industry standard DZ/T0217-2020 “Specifications for the Calculation of Petroleum and Natural Gas Reserves” [16], depths between 3500 and 4500 m are classified as deep layers, while depths exceeding 4500 m are categorized as ultra-deep layers. The majority of the study area in the present study has a burial depth exceeding 3500 m. At present, the X Depression is recognized as a crucial petroliferous sedimentary basin, holding significant potential for oil and gas exploration. The primary focus within the X Depression is low-porosity and low-permeability tight sandstone, which represents a major target for exploration and development with promising prospects in the study area. However, the gas field is characterized by complex geological features, with deeply buried target layers and generally poor reservoir physical properties. The relationship between porosity and permeability is intricate, marked by strong heterogeneity, and the development of low-permeability and tight gas reservoirs is evident.

The reservoir formation in the X Depression area originates from the underwater distributary channels sand body of a lake-braided river delta system, which is characterized by its complex distribution. The lithology of the area is predominantly medium sandstone and fine sandstone, with additional components of siltstone, coarse sandstone, and conglomerate. The primary rock type is feldspathic lithic quartz sandstone. The quartz content

in the sandstone ranges from 58% to 70%, the debris content ranges from 15% to 30%, and the feldspar content ranges from 15% to 22%. The interstitial fillings of the reservoir rock are mainly argillaceous, with occasional calcite, dolomite, and siliceous cementation. The cementation types are primarily contact-embedded types. Particle contacts are mainly point-line, followed by concave-convex-line. The sorting is good, and the roundness is predominantly sub-angular and sub-rounded. Considering grain size, sorting, roundness, and sedimentary mechanisms, the lithofacies in the study area are classified into five types (Table 1). The reservoir exhibits poor seepage capacity and significant heterogeneity. The primary range of porosity is 6% to 15%, with an average of 9.69%. The primary range of permeability is 0.1 mD to 70 mD, with an average of 11.7 mD. As the reservoir depth increases, the reservoir becomes increasingly dense and the physical properties deteriorate, representing a typical low-porosity and low-permeability reservoir.

Table 1. Lithofacies classification of sandy conglomerate reservoirs.

Type	Conglomerate Content	Sandstone Content	Mudstone Content	Sorting	Rounding	Sedimentary Structure	Sedimentation Mechanism	Sedimentary Microfacies
Siltstone	<10%	>50%	<15%	medium	Subangular-subrounded	Horizontal lamina	traction flow	Overbank sand body, Subaqueous distributary channel
Fine sandstone	<10%	>50%	<10%	good, medium	Subangular-subrounded	Parallel bedding, tabular cross-bedding, flute cross-bedding	traction flow	Low-energy braided river
Medium sandstone	<10%	>40%	<10%	medium	Subangular-subrounded	tabular cross-bedding, flute cross-bedding	traction flow	High-energy braided river
Coarse sandstone	<10%	>40%	<10%	good, medium	Subangular-subrounded	Parallel bedding, ripple bedding	traction flow	High-energy braided river
Conglomerate	>50%	<25%	<10%	medium	Subangular-subrounded	Massive bedding	traction flow	Subaqueous distributary channel

3. Pore Structure Characteristics of Tight Sandstone Reservoirs

Permeability and its distribution are typically assessed using core data. Based on the analysis of porosity and permeability data from approximately 5000 core samples measured via helium gas testing, in addition to the relationship between core porosity and permeability in the study area, as shown in Figure 1, it is evident that although permeability generally increases with porosity, the relationship between porosity and permeability is complex and poorly correlated. The study area displays significant heterogeneity, resulting in a wide range of permeability distributions. Traditional regression models that correlate core porosity and permeability often fail to meet accuracy requirements due to these complexities. Furthermore, the scarcity of core samples from many wells, combined with strong physical heterogeneity, contributes to inaccuracies in permeability estimation. To address these limitations, in the following paper, we introduce a novel approach: categorizing reservoirs based on pore structure and subsequently establishing distinct porosity–permeability relationship models to enhance the accuracy of permeability calculations.

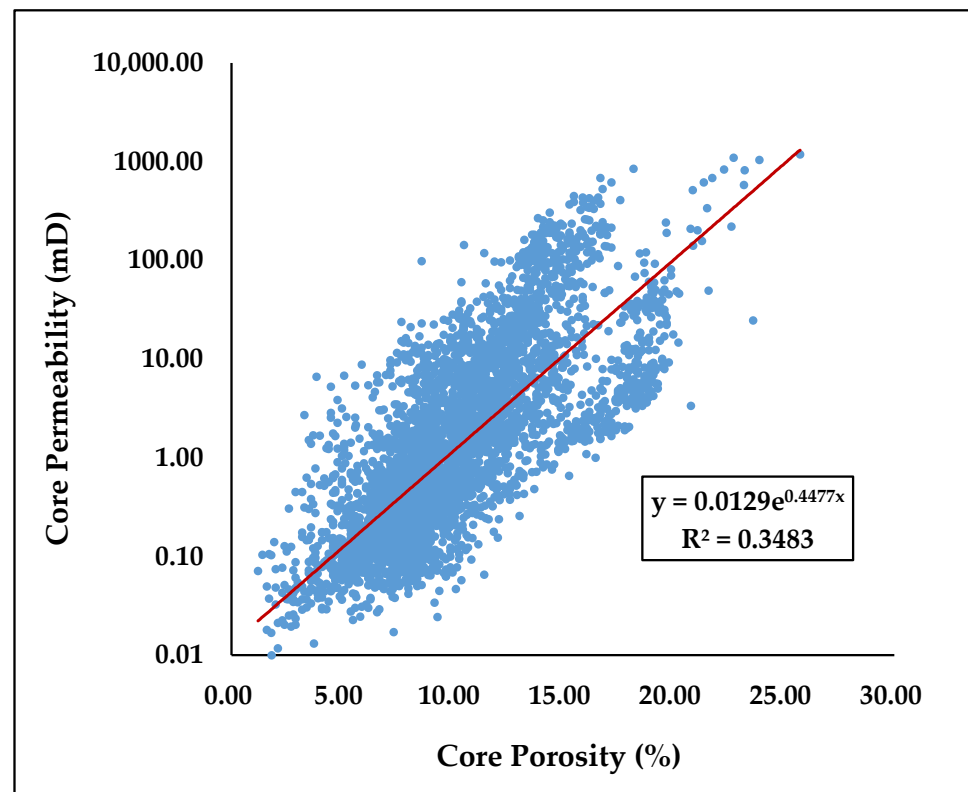


Figure 1. The relationship between core porosity and core permeability in the study area.

Based on experimental data from core thin section identification and mercury injection analysis in the study area, the reservoir was analyzed and the findings were summarized, allowing for an intuitive assessment of the pore structure characteristics.

Using a polarizing microscope to observe the structure and mineral composition of cast thin sections, it was found that the sandstone in the study area exhibits a diverse range of pore structure types. The primary types include intergranular dissolved pores and intragranular dissolved pores, with moldic pores and cracks being secondary types (Figure 2). This diversity contributes to the complex pore structure and significant heterogeneity within the reservoir. An analysis of core grain size data indicates that the study area predominantly consists of medium and fine sandstone, characterized by complex pore structures (Figure 3). Pores act as direct indicators of a rock's capacity to store oil and gas, with the pore throat shape, size, and distribution being crucial factors affecting reservoir permeability. The pore structure not only determines the effective storage capacity and fluid flow characteristics, but also significantly influences the logging response behaviors of the reservoir. Consequently, pore structure is a key consideration in the logging evaluation of low-permeability tight oil and gas reservoirs, and accurately determining pore throat attributes is essential for effectively classifying the reservoir into units with similar hydraulic properties [17,18].

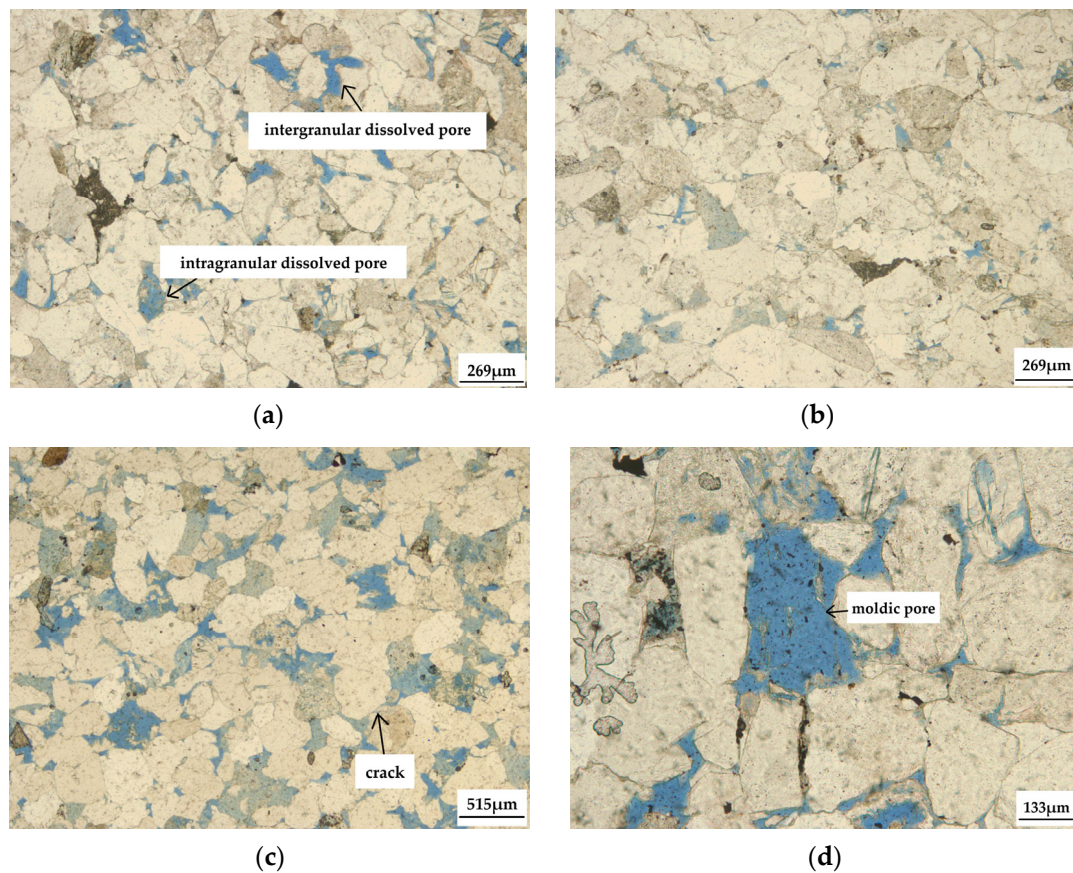


Figure 2. Sand casting body slices of the X Depression observed using a polarizing microscope: (a) Well XX7-1, 3843.7 m; (b) Well XY7-5, 4297 m; (c) Well XY7-1, 3126 m; (d) Well XY2-1, 3853.4 m.

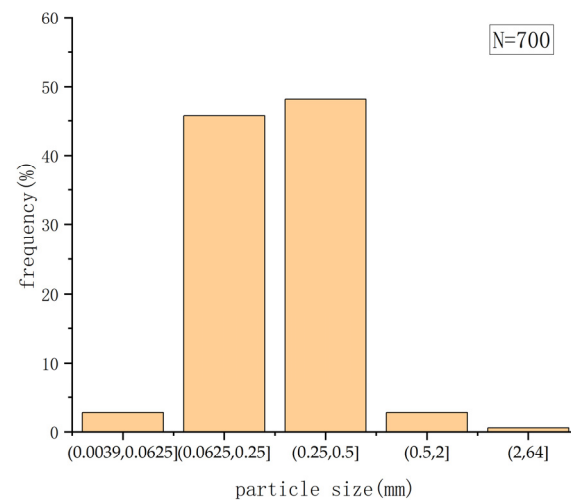


Figure 3. Histogram of particle size distribution.

The pore structure characteristics of a reservoir are comprehensively and accurately reflected through the capillary pressure curve and the morphological attributes of the pore throat radius distribution. A wide range of parameters used to assess pore structure quality can be obtained, facilitating more effective classification of reservoir types [19–21].

To establish a set of reservoir classification criteria based on pore structure suited to the study area, an analysis of mercury injection experimental data was conducted. The mercury injection experiments involved using a mercury intrusion porosimeter to analyze the mercury injection volumes of over 200 core samples at various pressures, thereby studying

their porosity and pore structure. Consequently, reservoirs can be roughly classified into four categories according to the mercury quantity curve, displacement pressure, pore throat size, sorting, and other parameters in the mercury injection analysis, as depicted in Figure 4. The diagram indicates that the displacement pressure of Type I reservoirs is low, with a long curve platform, suggesting thick pore throats, relatively good sorting, and favorable rock physical properties. Type II reservoirs exhibit higher displacement pressures than Type I reservoirs, with a shorter curve platform, indicating coarser pore throats, relatively good sorting, and moderate rock physical properties. Type III reservoirs show even higher displacement pressures compared to Type II reservoirs, with a shorter curve platform, poorer sorting, and worse rock physical properties. Type IV reservoirs, with slightly higher displacement pressures than Type III reservoirs, are characterized by poor sorting, the worst pore structure, and the poorest physical properties. Overall, the mercury injection curve platforms of Type I, Type II, Type III, and Type IV reservoirs progressively become shorter and steeper with increasing displacement pressure, reflecting a deterioration in physical properties and pore structure from Type I to Type IV.

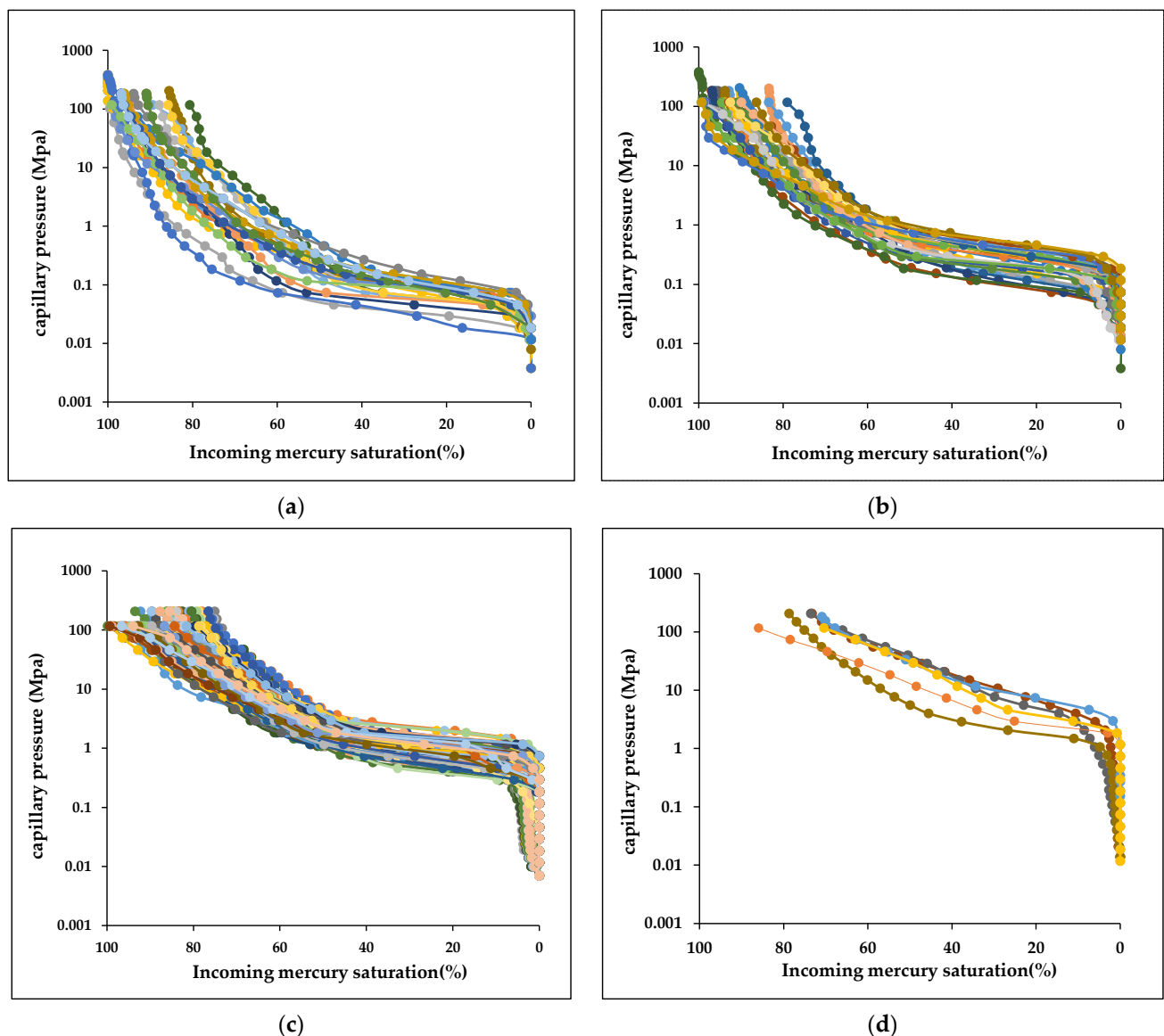


Figure 4. Layered mercury curves of different types of reservoirs: (a) Type I reservoir's layered mercury curve; (b) Type II reservoir's layered mercury curve; (c) Type III reservoir's layered mercury curve; (d) Type IV reservoir's layered mercury curve.

Based on conventional petrophysical properties and mercury injection capillary data, the characteristic parameters of pore structures for various reservoir types were determined. Table 2 illustrates significant variations among these reservoir types with respect to parameters such as porosity, permeability, grain size, pore throat radius, drainage pressure, and skewness.

Table 2. Characteristic parameters of the pore structure of different types of reservoirs.

Characteristic Parameter		Type I	Type II	Type III	Type IV
Porosity (%)		<u>2.25–25.7</u> 13.525	<u>1.7–22.6</u> 11.788	<u>1.6–23.6</u> 10.43	<u>2.7–20.8</u> 9.098
Permeability (mD)	min–max average	<u>1.7–850</u> 174.227	<u>0.037–221</u> 45.204	<u>0.01–53.7</u> 6.882	<u>0.013–10.1</u> 0.737
FZI (μm)		<u>4.51–12.6</u> 6.983	<u>2.29–4.442</u> 3.261	<u>1.038–2.284</u> 1.495	<u>0.0157–1.037</u> 0.638
lithology		mainly medium sandstone	fine sandstone and medium sandstone	fine sandstone and medium sandstone	mainly fine sandstone
Median grain size (mm)		>0.2	0.2–0.7	0.1–0.5	<0.2
Maximum pore throat radius (μm)		<u>3.55–35.71</u> 19.287	<u>1.166–40.54</u> 12.298	<u>0.0082–15.32</u> 5.192	<u>0.0375–10.208</u> 1.845
Average pore throat radius (μm)		<u>0.33–12.24</u> 5.448	<u>0.248–9.85</u> 5.189	<u>0.012–10.72</u> 2.053	<u>0.0102–9.33</u> 0.508
Drainage pressure (MPa)		<u>0.001–0.11</u> 0.012	<u>0.01–0.63</u> 0.072	<u>0.01–1.6</u> 0.451	<u>0.1–2.96</u> 1.830
Median pressure (MPa)	min–max average	<u>0.0625–0.63</u> 0.268	<u>0.13–1.26</u> 0.730	<u>0.774–4.59</u> 1.851	<u>3.98–28.71</u> 15.410
Structure coefficient		<u>0.0086–15.81</u> 2.687	<u>0.08–51.9</u> 5.382	<u>0.0025–72.98</u> 5.275	<u>0.015–794.79</u> 4.517
Skewness		<u>0.342–2.599</u> 1.784	<u>0.298–2.57</u> 1.546	<u>0.217–2.909</u> 1.612	<u>0.086–2.64</u> 1.649
Relative sorting coefficient		<u>0.217–1.421</u> 0.595	<u>0.21–2.822</u> 0.538	<u>0.154–8.59</u> 0.570	<u>0.13–17.08</u> 0.371

Through the meticulous classification of reservoirs with varying pore structures within the study area, we were able to ensure that each reservoir type exhibits distinctly similar rock physical properties. This approach facilitates the establishment of corresponding permeability calculation models. For the calculation of permeability within the study block, a model based on the division of the flow zone index according to reservoir types was employed.

4. Division of Flow Units and Establishment of the Permeability Model

The percolation capacity of a reservoir is characterized by the flow unit [22]. The flow zone index (FZI) is theoretically related to the capillary pressure curve and serves as a comprehensive parameter encompassing pore throat characteristics, rock structure, and mineral geological characteristics [23,24]. Utilizing this parameter allows for the determination of pore structure and the relationship between reservoir porosity and permeability, thereby improving the accuracy of classification of reservoirs with diverse pore structures [25,26]. Each flow unit demonstrates a uniform distribution of pore throat sizes and similar flow characteristics. A higher FZI signifies a stronger correlation between reservoir porosity and throat structure.

The concept of hydraulic unit radius is crucial for linking porosity, permeability, and capillary pressure. Referring to the average hydraulic radius, Kozeny and Carman

proposed that reservoir rock can be modeled as a bundle of capillary tubes [27,28]. By applying Poiseuille's law and Darcy's law, a relational expression is derived, leading to the generalized form of the Kozeny–Carmen equation:

$$K = \frac{\phi_e^3}{(1 - \phi_e)^2} \frac{1}{F_s \tau^2 S_{gv}^2} \quad (1)$$

where K is the permeability, μm^2 ; F_s is the shape factor, dimensionless; τ is the degree of curvature of the porous medium, fraction; $F_s \tau^2$ is often referred to as the Kozeny constant; S_{gv} is the surface area per unit grain volume, μm^{-1} ; ϕ_e is the effective porosity, fraction.

Building on this foundation, Amaefule et al. [29] employed parameters such as the flow zone index (FZI) and reservoir quality index (RQI) to identify and characterize hydraulic units with similar geometric properties to pore throats. The key parameters are as follows:

$$RQI = 0.0314 \sqrt{\frac{K}{\phi_e}} \quad (2)$$

ϕ_Z is defined as the pore volume to grain volume ratio.

$$\phi_Z = \frac{\phi_e}{1 - \phi_e} \quad (3)$$

Then, the flow zone index can be expressed as:

$$FZI = \frac{1}{\sqrt{F_s} \tau S_{gv}} = \frac{RQI}{\phi_Z} = 0.0314 \frac{1 - \phi_e}{\phi_e} \sqrt{\frac{k}{\phi_e}} \quad (4)$$

In the formula, K is the permeability, mD; FZI is a comprehensive parameter that reflects the physical properties and pore structure characteristics of reservoirs, μm ; RQI is the reservoir quality index in micrometers, μm ; ϕ_Z is the standardized porosity index, fraction.

This method demonstrates broad applicability in predicting permeability for both cored and uncored wells.

The cumulative frequency method was employed to classify the flow units, with the cumulative frequency distribution of the FZI depicted in Figure 5. Sample points positioned along the same curve in the diagram exhibit comparable pore structure characteristics and are thus classified into the same flow unit. Based on this classification, four distinct flow unit zones were identified, with the criteria for this division presented in Table 3.

Table 3. Permeability models of different flow units.

Flow Unit Type	FZI/ μm	Permeability Calculation Model	R ²
I	FZI > 4.4925	$K = 0.0232\phi^{3.2757}$	R ² = 0.7800
II	2.2875 < FZI < 4.4925	$K = 0.0073\phi^{3.2190}$	R ² = 0.7831
III	1.038 < FZI < 2.2875	$K = 0.0012\phi^{3.3611}$	R ² = 0.7659
IV	FZI < 1.039	$K = 0.0004\phi^{3.0827}$	R ² = 0.8026

In the logarithmic plot of RQI versus ϕ_Z (Figure 6), sample points with similar FZI values align on a straight line with a unit slope, while sample points with differing FZI values appear on parallel straight lines. Samples that lie on the same straight line exhibit similar pore throat attributes, indicating that they belong to the same flow unit.

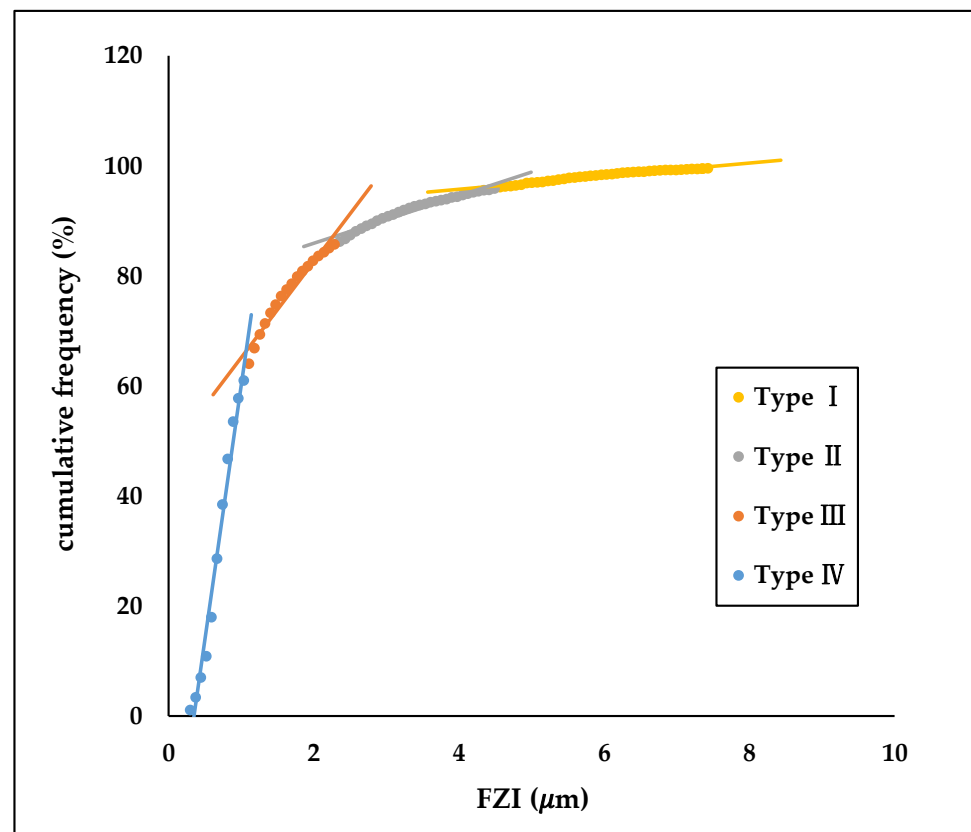


Figure 5. The cumulative frequency distribution of the FZI in the X Depression.

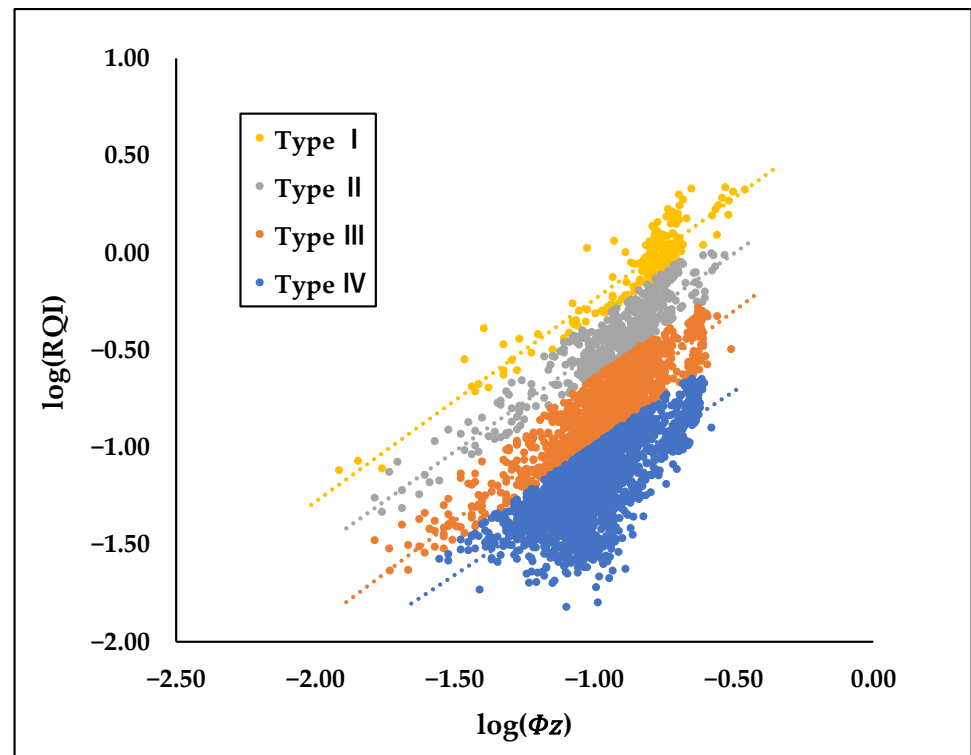


Figure 6. Distribution of different flow units.

In the study area, the reservoir is classified into four types of flow units based on the criteria detailed in Table 3 (where K is measured in mD and Φ represents a fraction). Each flow unit type is associated with a specific permeability calculation model. The relationship between porosity and permeability, as determined by the classification of reservoir flow units, is illustrated in Figure 7. This figure demonstrates a significant improvement in the pore–permeability relationship following classification.

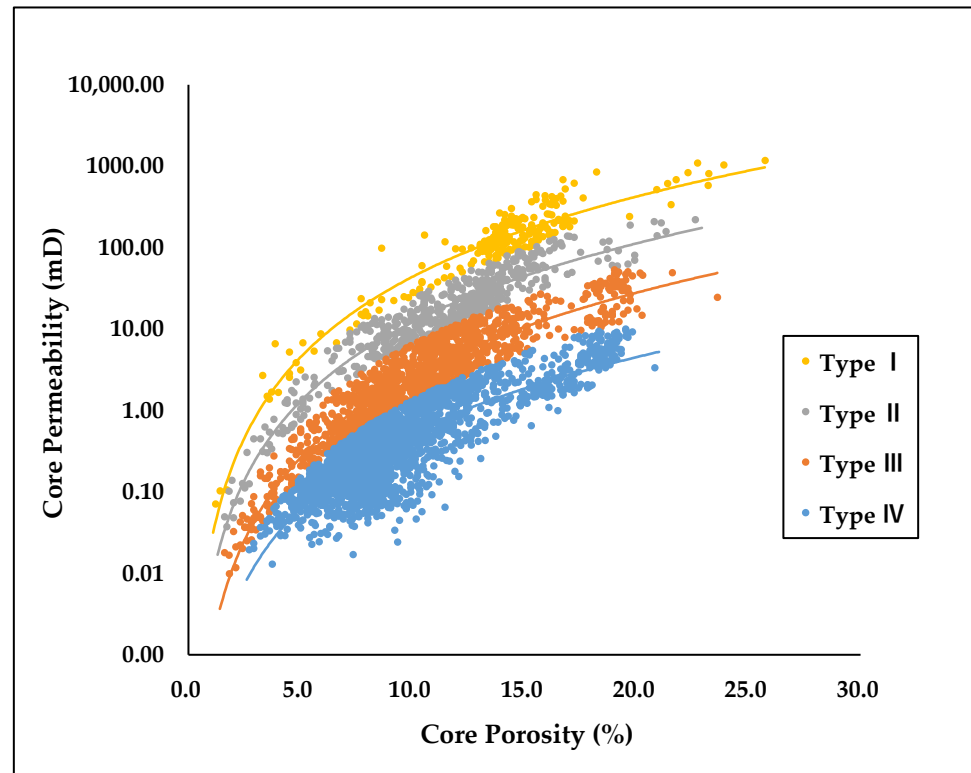


Figure 7. The relationship between porosity and permeability after reservoir classification based on the FZI.

In cored intervals, the flow zone index is directly derived from core analysis data for reservoir classification. Conversely, in uncored intervals or wells, only the quantitative relationship between the reservoir flow zone index and logging response parameters can be established based on logging data. Generally, the logging curve that reflects pore structure characteristics should be prioritized first, followed by the calculation of the flow zone index and identification of reservoir types. Subsequently, continuous and accurate permeability calculations for the entire well section can be conducted. The logging response characteristics of well XY2-1 in the X Depression are illustrated in Figure 8. In the coring section from 3780 to 3805 m, the natural gamma value is generally low, primarily ranging from 43 to 58 API. However, in the interval from 3802 to 3804 m, the natural gamma value increases significantly, with a minimum value of 63 API, indicating a rise in argillaceous content. This increase leads to thinner pore throats, decreased permeability, and a reduction in the FZI. In the well interval from 3790 to 3800 m, the compensated density and acoustic interval transit time shift to the left and the amplitude difference between deep and shallow resistivity increases significantly. This change is associated with a notable improvement in permeability and a higher FZI.

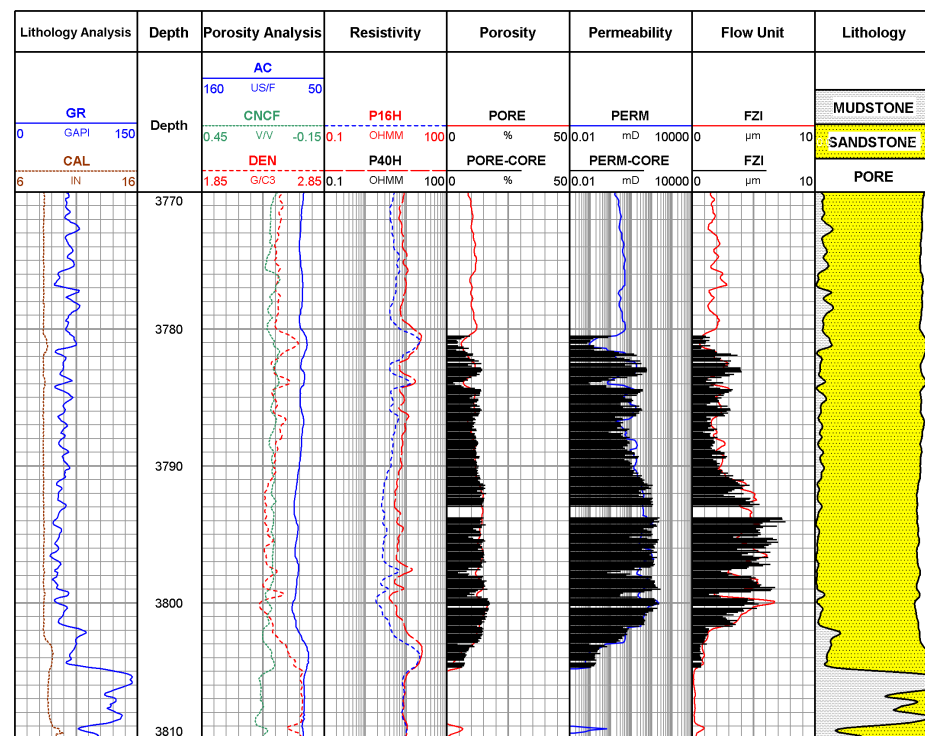


Figure 8. Conventional logging response diagram of well XY2-1.

Through the analysis of conventional logging response characteristics in coring wells, it is evident that the response attributes of natural gamma (GR), compensated density (DEN), acoustic transit time (AC), and both deep and shallow resistivity curves (P40H and P16H) are pronounced, showing a strong correlation with the flow zone index (as illustrated in Figure 9). The ratio of deep resistivity to shallow resistivity serves as an indicator of reservoir permeability. Consequently, natural gamma, compensated density, acoustic interval transit time, and the deep-to-shallow resistivity ratio were selected as variables for establishing a multi-parameter fitting equation for the flow zone index (FZI), achieving an R^2 value of 0.89.

$$\ln FZI = -0.028GR + 0.064 \left(\frac{P40H}{P16H} \right) + 0.037AC - 4.01DEN + 9.62 \quad (5)$$

where the FZI is measured in μm , GR is measured in API units, $P16H$ and $P40H$ are measured in $\Omega\cdot\text{m}$, AC is measured in $\mu\text{s}/\text{ft}$, and DEN is measured in g/cm^3 .

Based on the FZI method, the logging interpretation results for permeability, calculated following the reservoir classification of well XY2-1 in the X Depression, are illustrated in Figure 8, which includes data from 231 core samples. The sixth track presents the permeability curve post classification. The relative error between the permeability calculated using the flow unit method and the core permeability is 50%; in comparison, the average relative error before classification was 107%. The seventh track displays the calculated FZI values. It is apparent that the permeability calculations following reservoir classification meet the standards for detailed reservoir evaluation, demonstrating high accuracy. Notably, in layers with complex physical properties, the calculated permeability also aligns closely with core permeability, indicating effective practical application. In comparison with the traditional model, the FZI method shows a significant improvement in permeability calculation accuracy, making it suitable for predicting the flow zone index (FZI) in other well sections of the same layer and for subsequent permeability calculations.

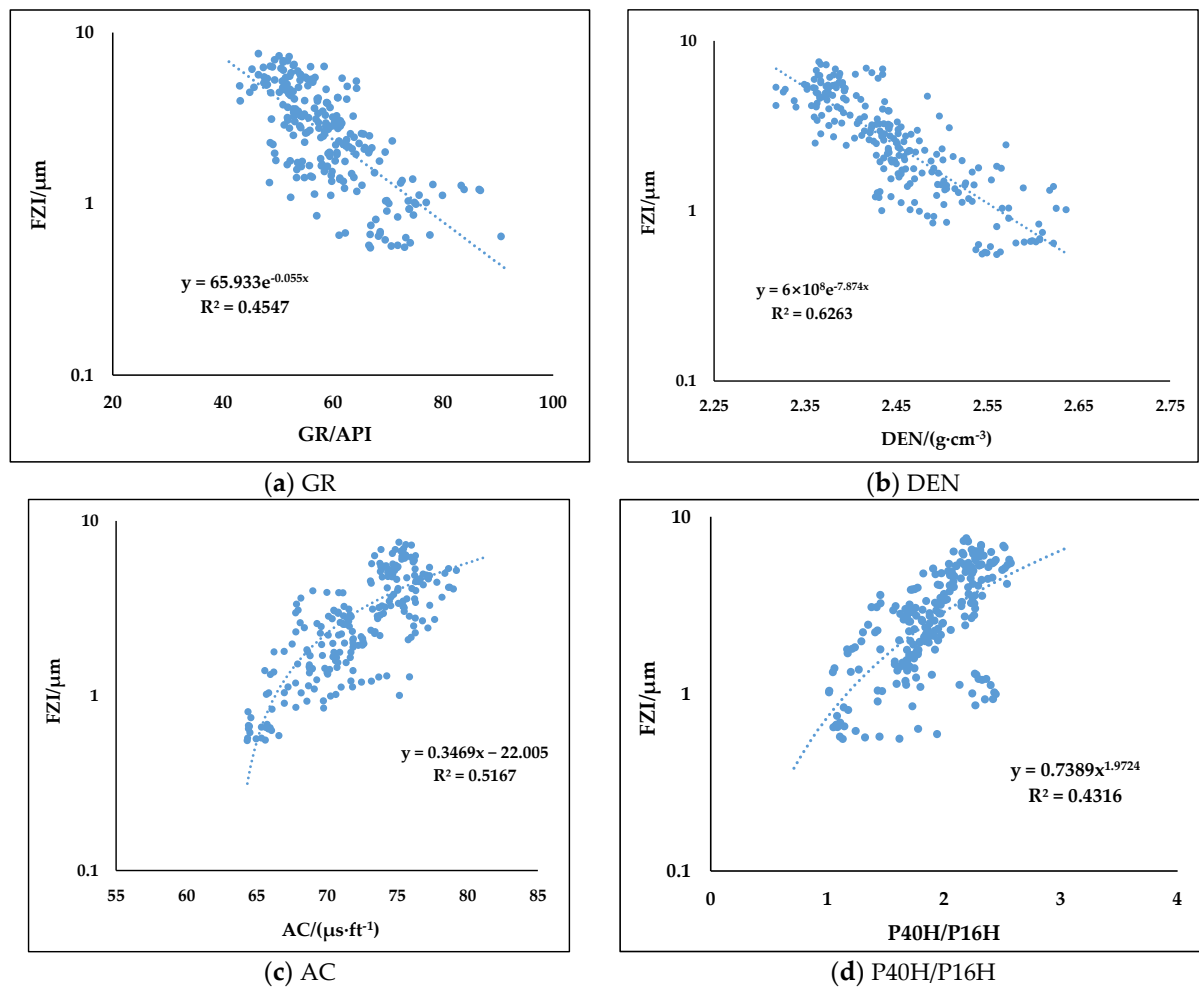


Figure 9. The correlation between single logging curves and flow unit index.

5. Derivation of the Upscaling Conversion Model

The drill stem test (DST) is a temporary completion testing method used during drilling operations. This method employs specialized tools, including packers and valves, positioned below the drill stem to conduct tests. The DST is widely regarded as the most effective and cost-efficient temporary completion method for obtaining the formation parameters of oil and gas reservoirs, fluid physical properties, original formation pressure, oil and gas well production, and the extent of mud damage to the formation [30]. It provides the advantages of rapid data acquisition and extensive information gathering. This method is crucial for enhancing the economic benefits of exploration and development. In gas well testing, there are two main methods for calculating permeability. A brief introduction is provided below. One method involves calculating permeability using conventional analysis methods. The corresponding formula is as follows [31,32]:

$$K = \frac{0.01467qT_f}{mh} \quad (6)$$

The second method involves calculating permeability using modern well test interpretation methods. The corresponding formula is as follows:

$$K = \frac{qT_f}{78.489h} \left(\frac{P_D}{\Delta\varphi(p)} \right) \quad (7)$$

where K is the permeability of the gas well, md; $\Delta\varphi_{(P)}$ is the pseudo-pressure, $\mu\text{Pa}^2/(\text{MPa}\cdot\text{s})$; P_D is the dimensionless pressure, dimensionless; q is gas well production, $10^4 \text{ m}^3/\text{d}$; T_f is the layer temperature, K; h is the gas layer thickness, m; m is the slope of the straight segment of the pressure build-up curve, $\text{MPa}/\logarithmic \text{ period}$.

In the traditional method, the thick layer permeability is mainly calculated using the point-by-point arithmetic average method, which represents the average permeability perpendicular to the sediment layer. This method does not consider the influence of reservoir heterogeneity and thickness on reservoir permeability. Hence, when extreme values or outliers are present, deviations from the true situation can occur. Through analysis of the above formulas (Formulas (6) and (7)), it becomes apparent that one of the main parameters determining dynamic permeability is the thickness of the gas layer. Therefore, based on reservoir classification, an effective thickness-weighted average method is proposed in the present paper. This method involves first calculating the average permeability for each flow unit and then determining the permeability of the test layer.

When fluid flow occurs parallel to the producing layer and the layers are nearly parallel, the system comprises three small layers with unequal permeability and equal pressure differences between them. The total flow rate, Q , equals the sum of the flow rates of each layer, and the total formation thickness, h , equals the sum of the thicknesses of each individual layer. Figure 10 illustrates the schematic diagram of the upscaling conversion model (where h is the layer thickness, L is the length, and W is the width).

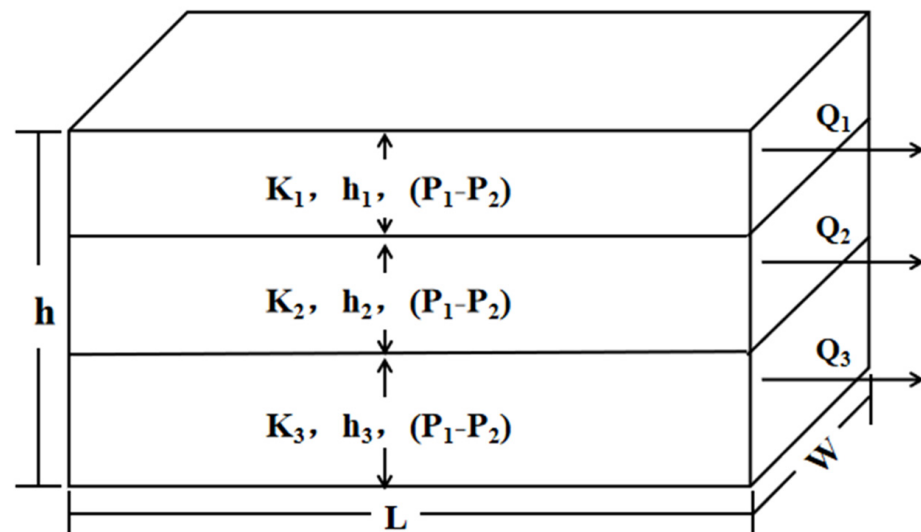


Figure 10. Upscale conversion model diagram, where $K = K_1 + K_2 + K_3$, $h = h_1 + h_2 + h_3$, $Q = Q_1 + Q_2 + Q_3$.

The formula for the effective thickness-weighted average method is:

$$K = \frac{K_1 h_1 + K_2 h_2 + K_3 h_3}{h_1 + h_2 + h_3} = \frac{\sum_{i=1}^n K_i h_i}{\sum_{i=1}^n h_i} \quad (8)$$

Equation (8) is the upscaling conversion formula of permeability. From the formula, it is evident that the influence of layer thickness is considered. According to this formula, the permeability of smaller layers can be transformed into the average permeability of larger layers.

The interlayer in a reservoir represents a non-permeable or low-permeability thin layer situated between oil and gas reservoirs. It manifests as a result of phase changes within micro-lithofacies or sandstone bodies and exhibits instability in distribution and morphology. Typically, these layers contain a high mudstone content, primarily silty mudstone or calcareous mudstone, with tight cementation significantly reducing local

permeability, resulting in interlayers that are not oil-bearing or that are oil-bearing but cannot be processed. To ensure the accuracy of permeability conversion, the influence of these interlayers must be excluded during evaluation. Interlayers act as barriers to reservoir fluids, impeding their penetration and flow. Thus, interlayers not only impact changes in reservoir permeability in all directions but are also challenging to track due to their instability. Utilizing logging curves and physical property analysis enables a more precise calculation of the effective thickness and permeability of the gas layer. Additionally, the number of interlayers can indicate the degree of reservoir heterogeneity, with a higher distribution of interlayers generally signifying a greater heterogeneity. Excluding the thickness of interlayers yields the effective reservoir thickness, which is essential for accurately calculating oil and gas reserves.

After removing the interlayers and based on the study of permeability upscaling conversion, the test layer was divided into several flow units. The average permeability for each unit was computed separately, followed by the calculation of the permeability for the thick layer using a weighted average method. This approach accounts for the heterogeneity of the reservoir, resulting in outcomes that more accurately reflect actual conditions. Permeability calculations for wells that had been subjected to DST tests were conducted using Formula (8). The results obtained via the effective thickness-weighted average method were found to be closer to the permeability values measured using DST tests compared to those obtained using the traditional point-by-point average method, and the calculated results are also more reasonable (Table 4).

Table 4. The calculation results of the upscaling method.

Well Name	DST Test Section /m	Effective Thickness/m	Effective Thickness Weighted Permeability/mD	Traditional Point-by-Point Average Permeability/mD	DST Permeability/mD	Thickness Relative Error/mD	Traditional Relative Error/%
XX27-5	4289.5~4313.3	37.2	1.85	2.15	1.58	17.08861	36.07595
XX17-1	4150.0~4169.0	39.9	0.55	0.55	0.544	1.102941	1.102941
XX27-1	4183.0~4196.0	26.2	6.48	5.457	6.88	5.813953	20.68314
XX25-1	4198.0~4277.0	54.5	16.63	23.99	13.9	19.64029	72.58993
XY22-1	3462.0~3507.0	18.6	1.23	1.15	1.32	6.818182	12.87879
XX13-7	3873.0~3903.0	29.4	1.85	1.63	3.9	52.5641	58.20513
XY13-4	4104.3~4126.0	23	25.47	23.28	29	12.17241	19.72414
XX14-3	3223.4~3242.0	18.1	2.3	1.8	8.12	71.67488	77.83251
XX25-3	2933.0~2949.0	9.9	172.69	164	488	64.6127	66.39344
XY27-1	2998.0~3012.0	18	76.27	77.47	40.8	86.93627	89.87745

The comparison diagram of the two averaging methods against the drill stem test (DST) permeability (Figure 11) reveals that while the results from both methods are close, the effective thickness-weighted average method is nearer to the diagonal line. The computed values align more closely with the DST permeability. Furthermore, the average relative error of the effective thickness weighted average method is 33.8%, compared to 44.5% for the traditional point-by-point arithmetic average method. These results demonstrate that the effective thickness-weighted average method is more accurate and meets the precision requirements, validating its greater degree of appropriateness.

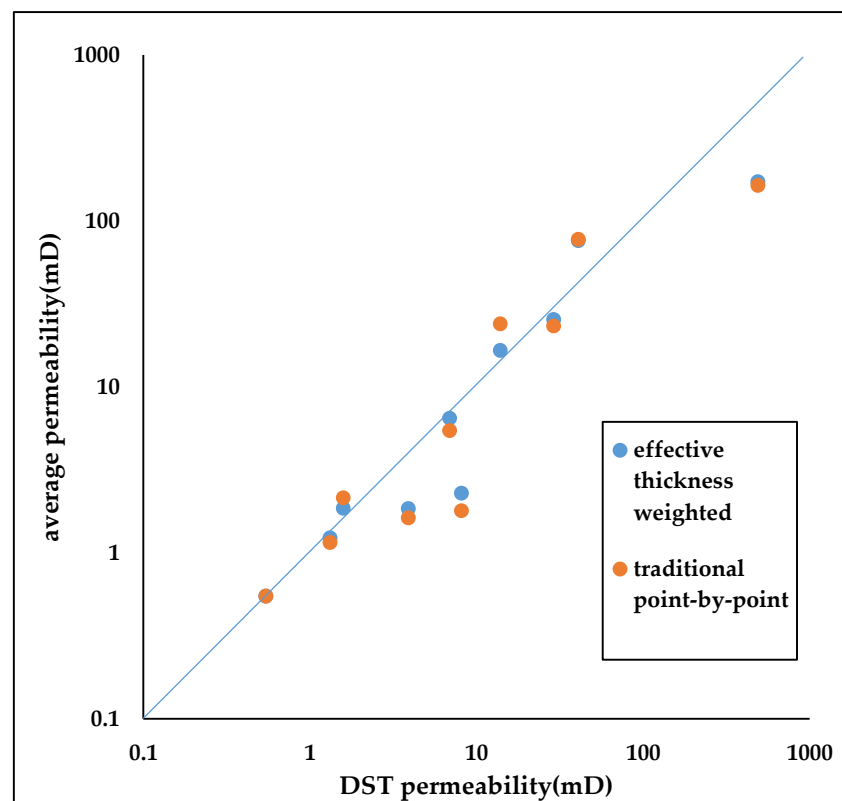


Figure 11. The comparison diagram of permeability calculated by two methods with the DST permeability of different wells in the X Depression.

6. Conclusions

In light of the results presented, the following conclusions can be derived:

- (1) Through the analysis of lithologic and physical characteristics in the study area, significant heterogeneity was observed, with permeability influenced by both porosity and pore structure. A classification standard for low-permeability reservoirs was established utilizing mercury injection and physical property analysis data. Building on this foundation, the flow unit method was employed to calculate reservoir permeability. Compared to traditional porosity and permeability models, the FZI permeability model exhibits superior accuracy, thereby affirming its improved applicability and precision in the X Depression.
- (2) Based on the concept of reservoir classification, the average permeability of each flow unit is calculated using logging data. According to Darcy's law, the effective thickness-weighted average method can be employed to determine the average permeability of heterogeneous thick layers. Compared to the traditional point-by-point arithmetic average method, this approach yields more reasonable results.

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Abbreviations

FZI	flow zone index	μm
DST	drill stem test	/
MDT	modular dynamics tester	/
K	permeability	mD
F_S	shape factor	/
τ	the degree of curvature of the porous medium	/
$F_S\tau^2$	Kozeny constant	/
S_{gv}	surface area per unit grain volume	μm^{-1}
ϕ_e	the effective porosity	/
RQI	reservoir quality index	μm
ϕ_Z	the pore volume to grain volume ratio	/
GR	natural gamma	API
DEN	compensated density	g/cm^3
AC	acoustic interval transit time	$\mu\text{s}/\text{ft}$
P40H	deep resistivity	$\Omega\cdot\text{m}$
P16H	shallow resistivity	$\Omega\cdot\text{m}$
$\Delta\varphi(P)$	pseudo-pressure	$\mu\text{Pa}^2/(\text{MPa}\cdot\text{s})$
P_D	dimensionless pressure	/
q	gas well production	$10^4\text{ m}^3/\text{d}$
T_f	layer temperature	K
h	gas layer thickness	m
m	the slope of the straight segment of the pressure build-up curve	MPa/log

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