

## Article

# Overpressure: Origin, Prediction, and Its Impact in the Xihu Sag, Eastern China Sea

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**Abstract:** The complex relationship between deep overpressure, abnormal porosity, and hydrocarbon generation in the Pinghu Formation is interesting and challenging for hydrocarbon exploration and development in the East China Sea Shelf Basin. It shows three-stage pore pressure evolution based on the characteristics of logs in the west slope of the Xihu Sag. Disequilibrium compaction was identified as the dominant overpressure mechanism in stage II ( $1.0 < PC < 1.6$ ). The fluid expansion was identified as the predominant mechanism of overpressure generation in stage III ( $PC > 1.6$ ), and tectonic compression occurs in Well B. Pore pressure was predicated by the Fillippone method based on the combination of raw velocity spectra and high-resolution velocity parameters obtained by seismic inversion. The overpressure at the bottom of the Pinghu Formation is mainly distributed in the F2 and F3 fault blocks. The deep gas reservoir of the Pinghu Formation is controlled by both lithology and pressure. The overpressure distribution area is consistent with the center of hydrocarbon generation. The overpressure distribution illustrated that overpressure was positively correlated with the porosity and permeability of the reservoir. The first porosity and permeability inversion zone of the Pinghu Formation formed because the overpressure caused by under-compaction offsets the pressure of some overlying strata and slows down diagenesis. Due to a large amount of hydrocarbon generation in source rocks, the acidic fluid with high temperature promoted the development of secondary pores, resulting in the second pore permeability inversion zone of the Pinghu Formation. The index of porosity preserving (IPP) is proposed here to quantitatively describe the relationship between overpressure and porosity. The index of porosity preserving in the second stage is 1.16%/10 MPa, and in the third stage is 1.75%/10 MPa. The results can be used to guide the exploration of the deep-basin gas reservoir of the Xihu Sag in the Eastern China Sea Basin.

**Keywords:** overpressure; pore pressure prediction; porosity preserving; Xihu Sag; East China Sea Basin



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## 1. Introduction

Overpressure is a key issue in hydrocarbon exploration because of the importance of safe drilling and its close relationship with reservoir planning. Many studies show that overpressure relates to hydrocarbon migration and accumulation and continually occurs with effective source rocks and reservoirs [1–3]. In the development process of natural gas reservoirs, it is significant for accurately predicting the formation pressure before drilling. Pore pressure prediction involves quantifying pore pressure from rock properties, such as velocity, density, and resistivity [4].

Understanding how different overpressure mechanisms affect rock properties and determining the origin of overpressure are necessary to predict pore pressure. Several mechanisms have been proposed for the origin of overpressure. Bowers (2001) divided the mechanism into the disequilibrium compaction (under-compaction), fluid expansion,

tectonic transfer, and pressure transfer [5]. Before the mid-1990s, the identification of overpressure relied on acoustic logs [6]. The disequilibrium compaction or under-compaction was considered a major cause for overpressure formation [7]. The effective stress acoustic velocity relationship method [8] has been successfully applied in many basins. It is found that overpressure in many basins is not caused by under-compaction but rather by fluid expansion caused by hydrocarbon generation or hydrothermal pressurization [9,10]. In the 21st century, smectite–illite transformation, tectonic compression, and pressure transfer have been confirmed as significant contributors to overpressure generation [11–13].

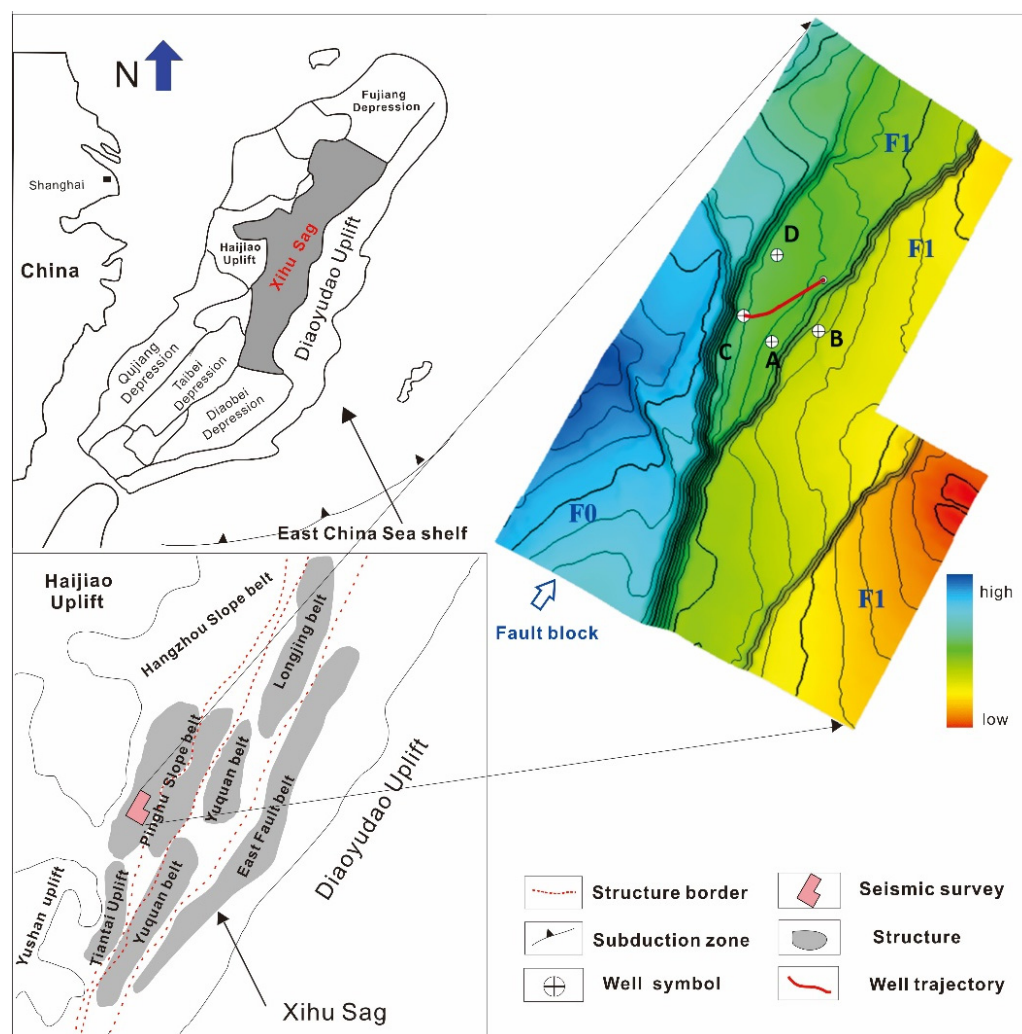
Pore pressure prediction involves quantifying pore pressure from rock property variations, particularly sonic velocity or resistivity [14,15]. Unlike overpressure caused by under-compaction, the pressure prediction based on porosity may underestimate the magnitude of overpressure caused by other mechanisms. Hence, it is necessary to confirm the overpressure mechanism and how different overpressure mechanisms affect rock properties in order to accurately predict pore pressure. Pore pressure prediction mainly depends on building models between pressure and velocity obtained from seismic data. Eaton [16] proposed a method to calculate formation pressure by establishing a normal compaction trend curve. Eaton's method and Bowers' method were proposed based on the relationship between velocity and effective stress. The accuracy of the compaction trend has a significant influence on the prediction of pressure by these two methods. The Fillippone method [17] uses the seismic velocity spectrum to calculate pore pressure without building a compaction trend line.

The influence of overpressure fluid on surrounding rock particles and pores has always been one of the focuses of oil and gas exploration. The constructive effect of overpressure on the reservoir is that it can support part of the overburden pressure, resulting in the preservation of primary pores [18]. Overpressure fluid takes away dissolved substances and causes further dissolution of feldspar particles during migration [19]. Many cases showed a positive correlation between pressure and porosity [20]. For example, sandstone will retain 1.9% porosity for 6.9 Mpa in the North Sea [21].

With the exploration and development in the Eocene Pinghu Formation of the Xihu Sag, in the East China Sea Basin, the wide distribution of overpressure was found. In particular, the possible correlation between the “sweet spot” found in the deep Pinghu Formation and the overpressure has attracted our attention. In this study, we first investigate the origins of overpressure in the west slope of the Xihu Sag and reveal three distinct mechanisms of overpressure. Then, we apply the Fillippone method to predict the pore pressure and confirm the distribution of overpressure in the Pinghu Formation. Finally, the influence of overpressure on gas reservoir is determined, and the influence of overpressure on reservoir porosity and permeability is analyzed quantitatively by the index of porosity preserving (IPP).

## 2. Geological Setting

This study area is located on the west slope of the Xihu Sag (Figure 1). The Xihu Sag of the East China Sea Shelf Basin is located on the western edge of the Pacific Plate. Under the influence of the Eocene Yuquan Movement and the Miocene Longjing Movement, three structural evolution stages occurred: fault depression, depression, and regional subsidence. The Pinghu oil and gas field is located on the Baochu slope in the Xihu Sag of the East China Sea Shelf Basin, connected to the Santan Sag in the east and the Pinghu main fault in the west. The Paleogene Huagang Formation and the Pinghu Formation are the primary hydrocarbon-bearing stratigraphic systems. During the Pinghu Formation and Huagang Formation, the depth of the water body changed considerably, and the sea–land facies changed frequently.



**Figure 1.** Index map showing the study area.

The Xihu Sag is a negative structural unit formed in the Cenozoic in the East China Sea Shelf Basin. According to the data of drilling gravity and magnetic exploration, the stratigraphy of the Xihu Sag is as follows: Pleistocene Donghai Group (Qd), Pliocene Santan Formation (N2s), Miocene Liulang Formation (N1ll), Miocene Yuquan Formation (N1yq), Miocene Longjing Formation (N1lj), Oligocene Huagang Formation (E3h), Eocene Pinghu Formation (E2p), Eocene Baoshi Formation (E2bs), Paleocene (E1). The basement material of the Xihu Sag is mainly composed of a large number of Cretaceous igneous rocks, including intrusion granite and contact metamorphic rock [22,23].

The strata, generation, lithological combination, and contact relationship characteristics of each group in the Pinghu oil and gas field are shown in Figure 2.

The Xihu Sag was filled with huge, thick clastic rock sediments in the process of structural evolution. The Eocene Pinghu Formation was formed in the rifting stage, and the sedimentation rate was as high as 120–300 m/MA. The thickness of the Pinghu Formation reached 1000–2000 m, revealed by drilling in the west slope of the Xihu Sag. This means that rapid sedimentation may lead to under-compaction of sediments in the Pinghu Formation.

The source rocks of Pinghu Formation in Xihu Sag mainly include dark mudstone, coal and carbonaceous mudstone. According to the study on the typical section, the series is composed of a set of gray and dark gray mudstone, siltstone, and fine sandstone and intercalated with a large amount of asphaltene coal. It is the primary source of rock in the Xihu Sag. The Pinghu Formation is within the oil and wet gas windows with determined vitrinite reflectance values in the range of 0.55–2.2% measured vitrinite reflectance (Rom).

Modeling results suggest that the main stage of hydrocarbon expulsion occurred during the Miocene [24,25].

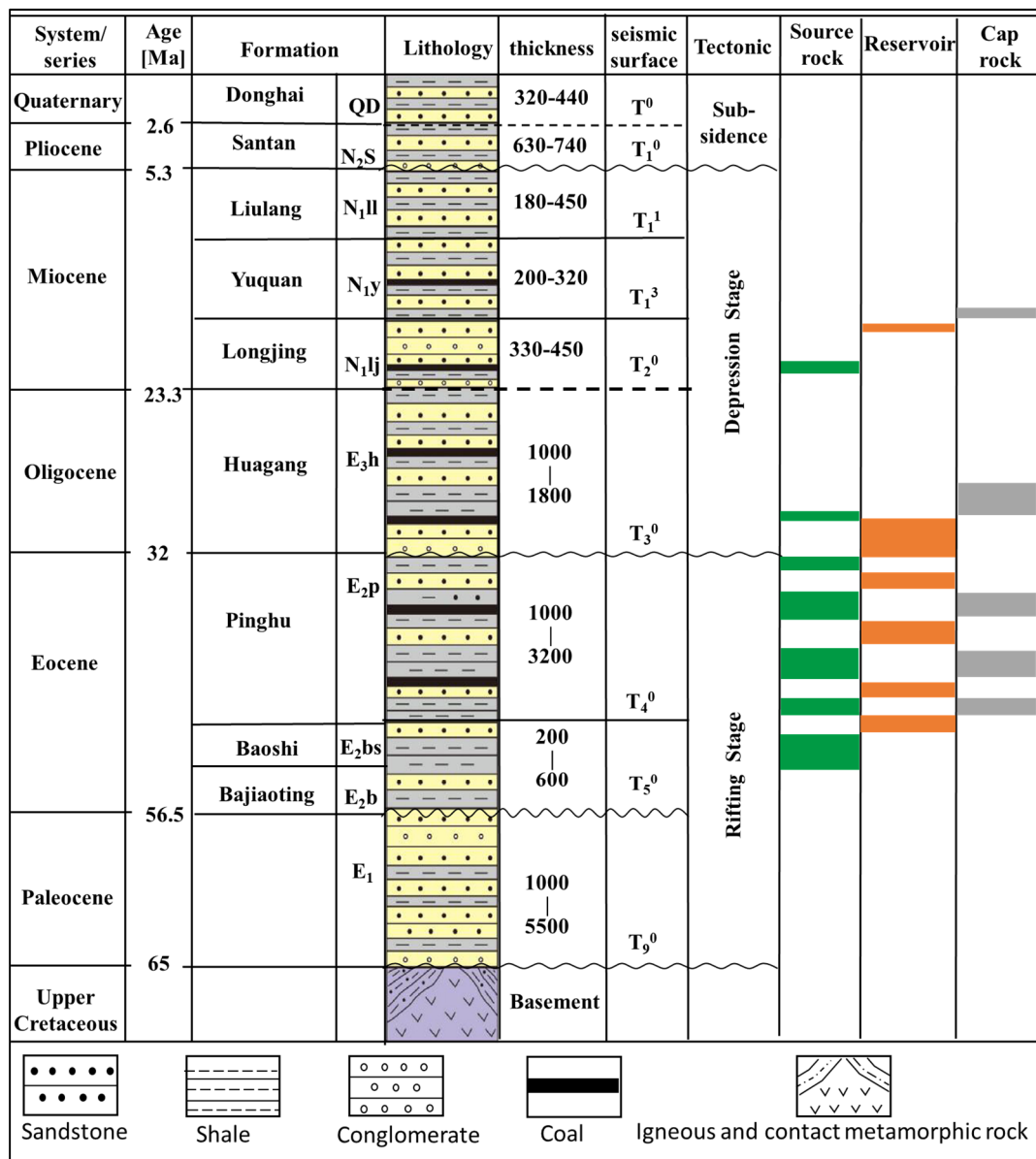


Figure 2. Stratigraphic column for the Xihu Sag.

### 3. Samples and Methods

#### 3.1. Samples Selection and Processing

Seventy-four measured pore pressures measured by drill stem test (DST) and mud weight (MD) data from wells in the Pinghu fields were collected from the Shanghai Petroleum Company (SPC). Sixteen sandstone samples in the Pinghu Formation (E<sub>2</sub>p) were collected from drilling cores and used to perform diagenesis observations using casting thin sections and a scanning electron microscope (SEM).

The log data used included P-acoustic, S-acoustic, density, resistivity, and neutrons.

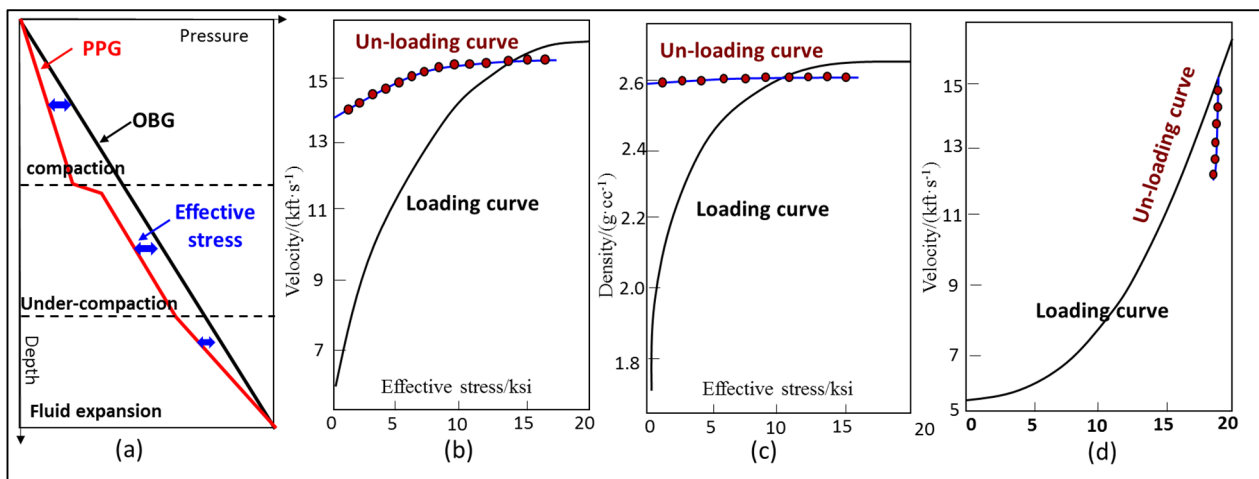
In the unconsolidated formation, borehole sloughing frequently occurs, resulting in acoustic and density deviation. By comparing the bit diameter with the well diameter, the abnormal data of the interval in which collapse may occur are excluded.

Velocity is the key to pressure prediction, and common reflection point (CRP) gathers were used for seismic inversion to calculate velocity parameters in the Pinghu field. To

calculate the velocity density parameters more accurately, the distortion gathers was muted and the random noise of CRP gathers was suppressed by the Radon transform.

### 3.2. Method for Identifying Overpressure Causes

In recent years, many significant advances have been made in empirical research on the causes of overpressure. The methods of identifying the causes of overpressure include direct practical methods and indirect inference methods. The former mainly refers to the geophysical overpressure–geophysical logging response characteristics analysis and experimental test analysis. The latter mainly refers to the theoretical analysis of the formation conditions of overpressure and the numerical simulation of the causes of overpressure. Six methods for identifying overpressure causes are proposed: analysis of logging, loading–unloading diagram (Bowers method), cross-plot between velocity and density, porosity comparison, inversion of pressure, and comprehensive analyses (Figure 3) [26].



**Figure 3.** Effective stress response to different overpressure mechanisms and Bowers diagram. (Modified from [5]).

#### 3.2.1. Analysis of Logging

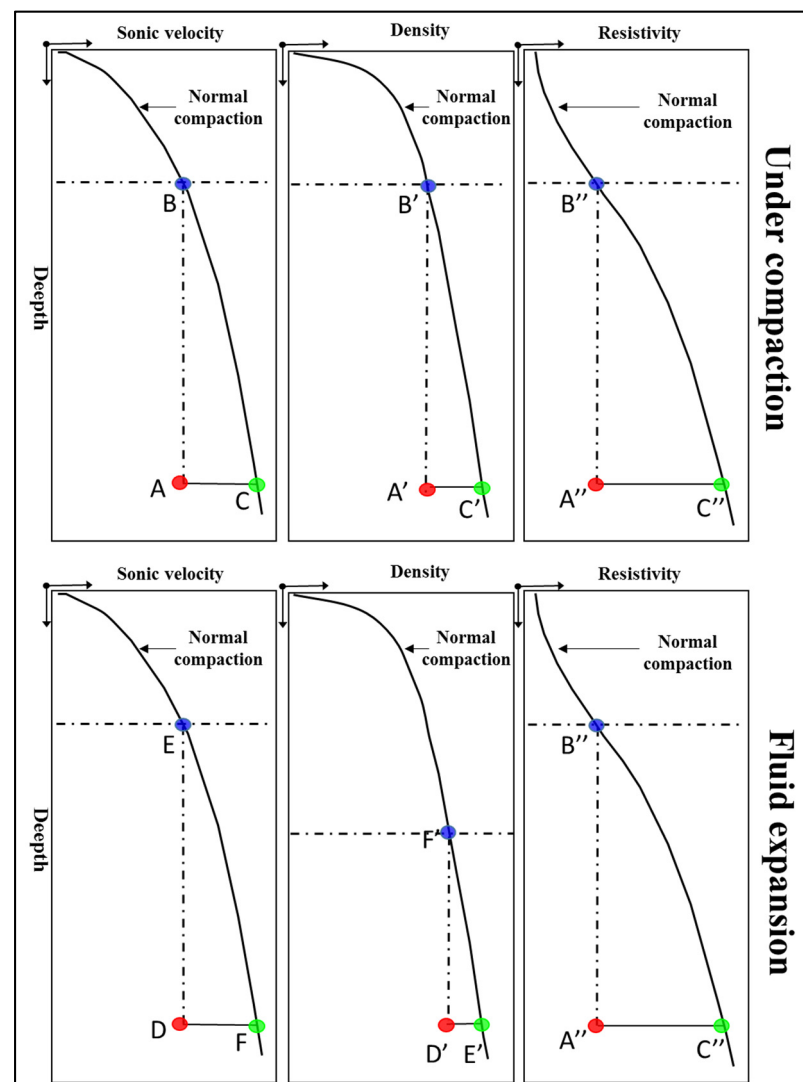
The first case of the origins of overpressure research using logging curves appeared in the 1970s [27]. It needs at least three logging curves: acoustic, resistivity, and density. The logging characteristics of different origins of overpressure are summarized as follows. (1) The logging characteristics of overpressure caused by disequilibrium compaction show that as the depth increases, the P-sonic increases or the velocity decreases, the resistivity decreases, and the density decreases significantly. (2) The logging characteristics of overpressure caused by fluid expansion show that as the depth increases, the P-sonic increases or the speed decreases, the resistivity increases, and the density remains unchanged or slightly decreases. (3) The logging characteristics of overpressure caused by tectonic compression show that as the depth increases, the P-sonic decreases or velocity increases, and resistivity and density increase (Figure 4).

However, many factors affect logging, so the accurate identification of overpressure diagenesis should also be analyzed with other methods and geological conditions.

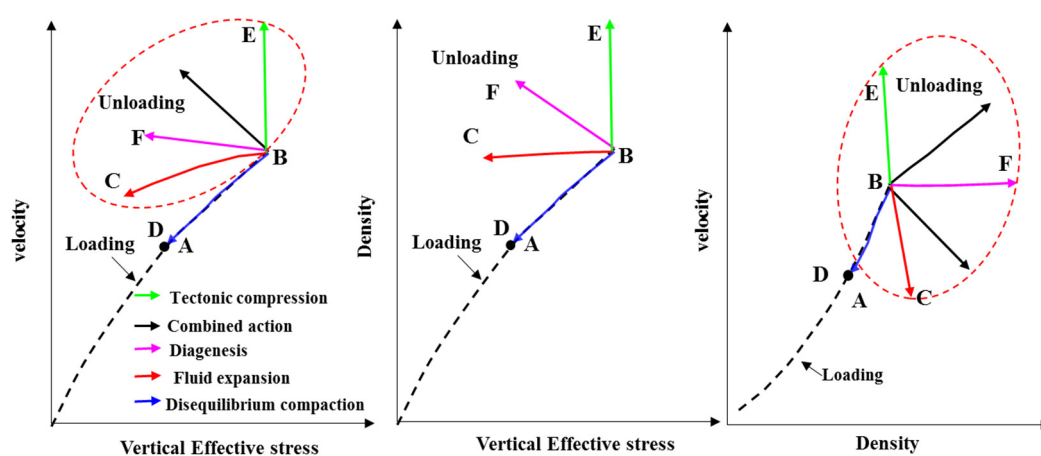
#### 3.2.2. Bowers Method

The loading–unloading curve method can be used to identify the cause of overpressure by forming plots of effective stress–velocity and effective stress–density.

The overpressure data caused by disequilibrium compaction are located on the loading curve in which porosity increases as vertical effective stress decreases. The overpressure caused by fluid expansion, diagenesis, and tectonic compression is located on the unloading curve in which porosity changes slightly as vertical effective stress decreases (Figure 5).



**Figure 4.** Response of multi-logging combination to an overpressure of disequilibrium and non-disequilibrium compaction.



**Figure 5.** Cross-plots of effective vertical stress vs. acoustic velocity/density and velocity vs. density for the different origins of overpressure.

### 3.2.3. Velocity–Density Plots

The density acoustic velocity method is developed based on the Bowers method and is used for the origins of overpressure. The overpressure data formed by disequilibrium compaction and tectonic compression lie on the loading curve. In contrast, the overpressure generated by other mechanisms lies in the unloading curve. Figure 5 shows the characteristics of different overpressure causes on the density–velocity cross-plot (Figure 5).

### 3.3. Method for Predicting Pore Pressure by Seismic

The velocity in a given medium is mainly a function of effective stress and porosity. Seismic data are used to identify a large-area three-dimensional velocity field and the primary basis for formation pressure prediction before drilling. Therefore, the effective stress can be calculated by seismic velocity, and then the pore pressure can be obtained. According to the response characteristics of pressure logging, the improved Fillippone method was used to predict pore pressure in the Xihu Sag.

The Fillippone method calculate fluid pore pressure based on layer velocity:

$$P_f = \frac{V_{max} - V_i}{V_{max} - V_{min}} P_{ov} \quad (1)$$

$$P_f = \frac{V_{mxp} - V_i}{V_{mxp} - V_{mnp}} P_{ov} \quad (2)$$

where  $P_f$  is pore pressure,  $P_{ov}$  is overburden pressure,  $V_{max}$  is the velocity of the rock matrix,  $V_{min}$  is the velocity of the pore fluid when the rock formation filled with fluid,  $V_{mxp}$  is the maximum compaction velocity of the formation,  $V_{mnp}$  is min velocity, and  $V_i$  is the layer velocity in the  $i$  layer.

This method does not need to establish a normal compaction trend line and only requires the layer velocity data as high as possible to solve the formation pressure. It works well in Mexico and elsewhere.

The method assumes a linear change between formation pressure and velocity, but the formation velocity is often complicated in practical applications. On this basis, Liu [28] found a logarithmic relationship between formation and velocity in the actual test data in the western Liaoning depression. The Fillippone method was modified:

$$P_f = \frac{\ln(V_i - V_{mxp})}{\ln(V_{min} - V_{max})} P_{ov} \quad (3)$$

$$P_{ov} = \rho \times k \times h \quad (4)$$

Furthermore, Yun [29] added the correction factor to the applicability of the Fillippone method, and improved the Fillippone formula and Liu's formula to:

$$P_f = Fv \frac{V_{max} - V_i}{V_{max} - V_{min}} P_{ov} \quad (5)$$

$$P_f = Lv \frac{\ln(V_i - V_{mxp})}{\ln(V_{min} - V_{max})} P_{ov} \quad (6)$$

where  $Fv$  and  $Lv$  are velocity correction factors, which can be calculated by fitting the measured pressure data of drilling wells. The speed parameters  $V_{max}$ ,  $V_{min}$ ,  $V_{mxp}$ , and  $V_{mnp}$  can be calculated by the following formula:

$$V_{max} = 1.4V_0 + 3KT \quad (7)$$

$$V_{min} = 1.4V_0 + 0.5KT \quad (8)$$

$$V_0 = 1.4V_j - KT_0 \quad (9)$$

$$K = \frac{V_J - V_{J0}}{T - T_0} \quad (10)$$

where  $T$  and  $T_0$  are the two-way travel time of the seismic wave at the bottom and top interface and  $V_{J0}$  and  $V_J$  are the root mean square velocities of the seismic wave at the top and bottom interface of the formation, respectively.  $Fv$  and  $Lv$  are velocity correction factors, which can be calculated by fitting the measured pressure data of drilling wells. An accurate velocity field is key for predicting pressure using the Fillippone method. There are two methods to calculate velocity: velocity analysis and pre-stack seismic inversion.

#### 4. Results

##### 4.1. Origin of Overpressure in the Xihu Sag

In this study, log data of Well A1, Well A3, and Well A6 were used to analyze the origins of overpressure in the Xihu Sag. Pore pressure data were obtained from drill stem test (DST) and mud density (MD) data. The overpressure starts with 3200 m. The evolution of pore pressure includes three stages. The first stage is the normal pressure zone with normal compaction. The second stage is the pressure transition zone with a pressure coefficient between 1 and 1.6, and the third stage is the overpressure zone with a pressure coefficient greater than 1.6 (Figure 6). Overpressure data are classified as “on loading curve” and “un-loading curve” according to the porosity–effective stress values for the overpressured sediments.

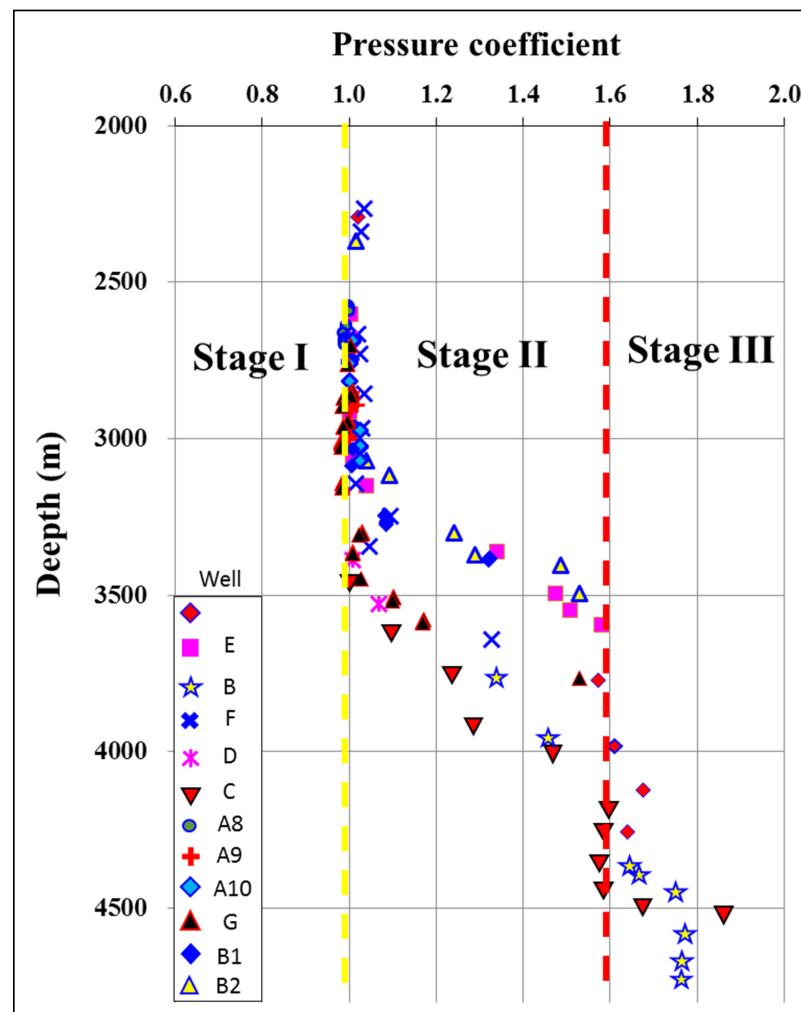
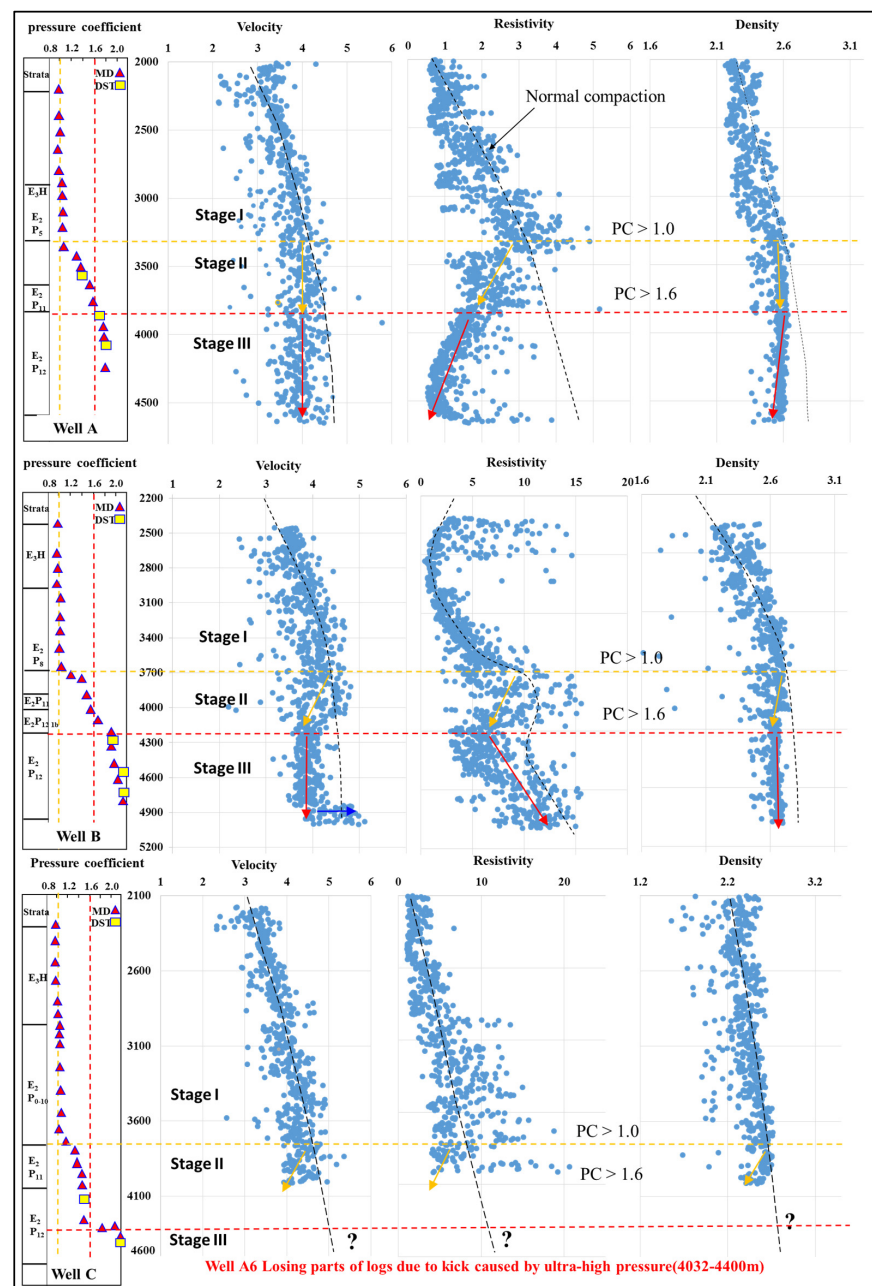
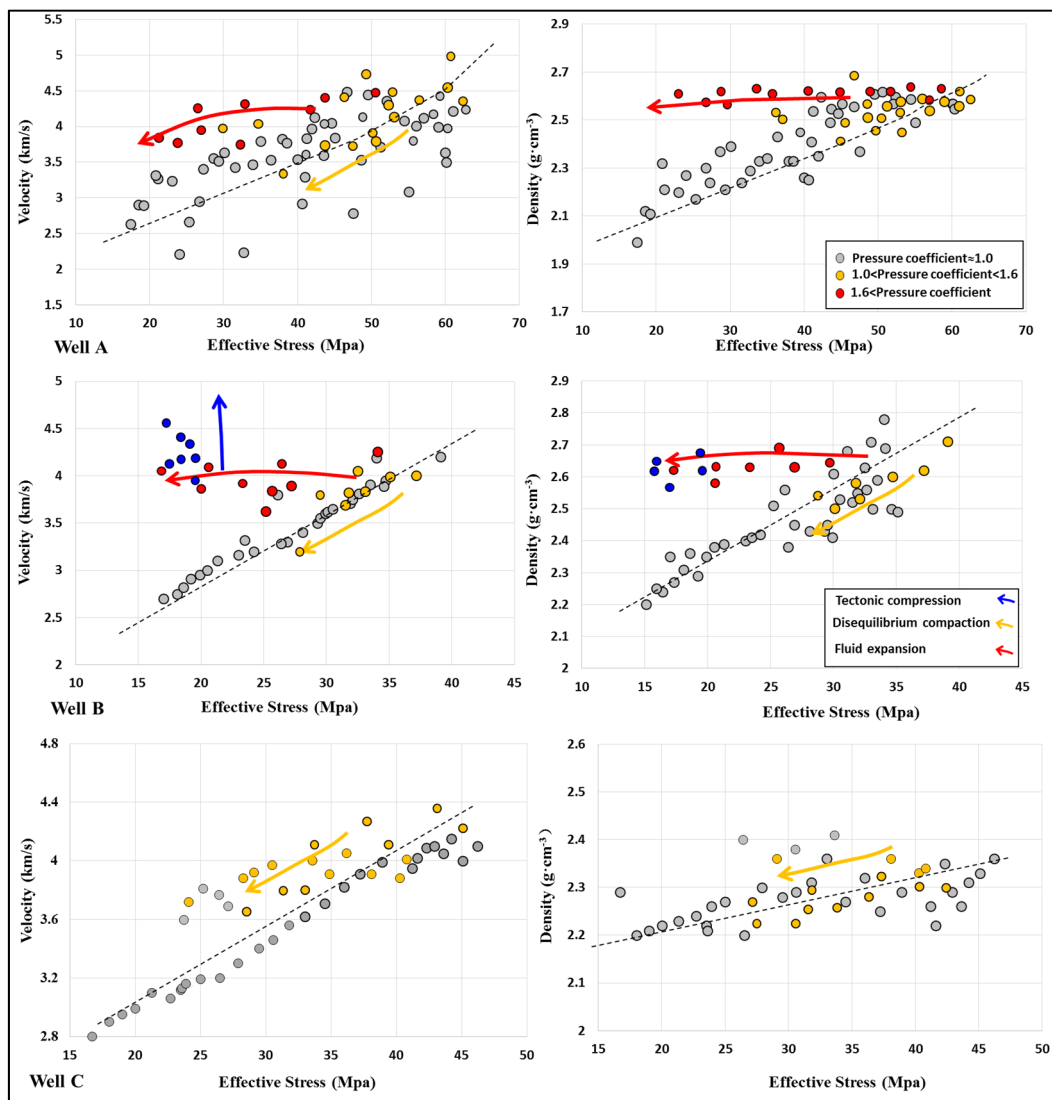


Figure 6. Pore pressure coefficient profile of the study area.

Overpressures in the Xihu Sag show two-stage characteristics. For Well A1, stage II of pore pressure evolution starts in Eocene  $E_2P_5$  with buried depths of 3350 m. As Figure 7 shows in stage II, the resistivity shows apparent reversal, while the velocity and density stop increasing with the burial depth and deviate from the normal compaction. In addition, the velocity/density–effective stress cross-plots (Figure 7) and velocity–density cross-plots (Figure 8) do not show any reversal in stage I. Hence, the under-compaction mechanism generates the pressure coefficient increase from 1.0 to 1.6. Stage III of pore pressure evolution turns up in Eocene  $E_2P_{12}$  with buried depths of 3350 m. With the increase in burial depth of stage III, the sonic velocity shows slight changes, but the density decreases. The overpressure data in plots of density–effective stress and velocity–density lie on unloading curves. These characteristics of logs and plots are similar to those of overpressure resulting from fluid expansion/pressure.



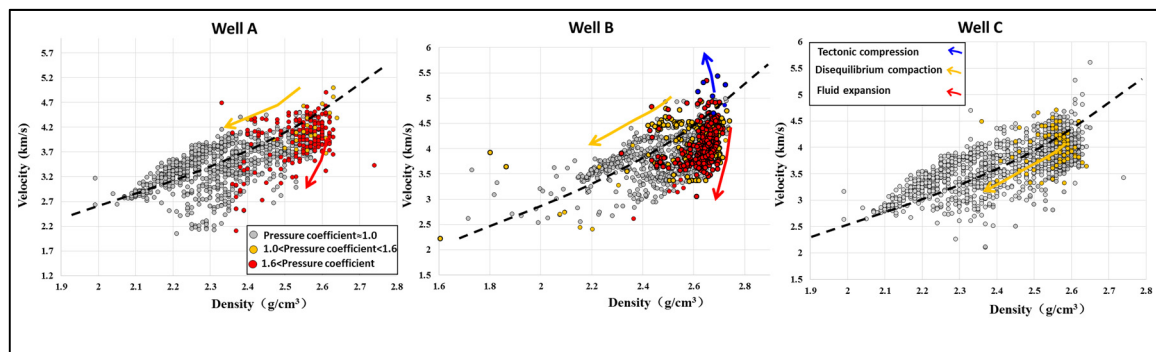
**Figure 7.** Depth profiles of well-logging parameters, including velocity, density, resistivity, mud weight (MD), and drill stem test (DST) data from Well A, Well B, and Well C.



**Figure 8.** Cross-plot between effective stress and velocity/density.

For Well A3, the overpressure (stage II) starts in Eocene E<sub>2</sub>P8 with buried depths of 3700 m. In stage II of pore pressure processing, velocity, resistivity, and density show an apparent reversal. The overpressure points fall on the loading curve in Bowers plots. Consequently, overpressure points in stage II are identified as disequilibrium. In stage III of overpressure, there is a slight variation in velocity and density. This indicates pore pressure's typical fluid expansion mechanism in Bowers plots (Figure 7). However, in the bottom of E<sub>2</sub>P<sub>12</sub> at 4850 m, velocity and resistivity increase rapidly and maximum velocity is faster than in stage II. This logging response is probably caused by lateral tectonic compression. The blue overpressure points (Figure 7) show the pattern of the tectonic compression mechanism in Figure 7.

The overpressure starts in Eocene E<sub>2</sub>P11 at 3760 m. Unfortunately, Well A6 encountered ultra-overpressure at a depth of 4500 m, resulting in a kick and losing the part of logs from 4032 m to 4434 m (TVD). According to the logging characteristic (Figure 7) from 3780 m to 4030 m (stage II) and Bowers plots (Figures 8 and 9), overpressure is generated from disequilibrium mechanisms. The origins of overpressure at the different stages are summarized in Table 1. The pressure coefficient of overpressure caused by under-compaction is between 1.0 and 1.6, and the pressure coefficient of overpressure caused by fluid expansion is greater than 1.6.

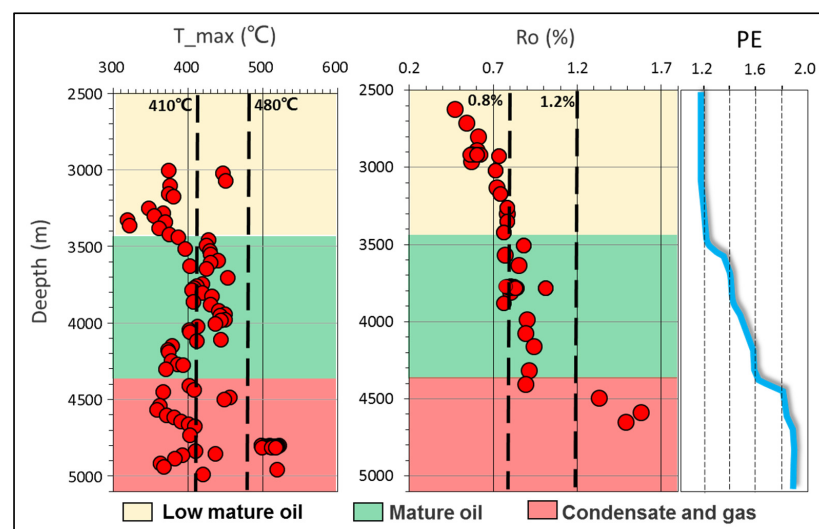


**Figure 9.** Vertical effective stress plotted against the velocity and density, covering units of age from Oligocene to Eocene and depth from 2400 m to 5100 m. Gray circles represent shales with normal pressure. Yellow and red circles represent overpressure shale. Overpressure data of Well A lie on the loading curve. Overpressure data of Wells B and C lie on the unloading curve.

**Table 1.** Mechanisms of overpressure in a different stage.

| Stage | Pressure Coefficient | Temperature | Well A                    | Well B                                   | Well C                    |
|-------|----------------------|-------------|---------------------------|------------------------------------------|---------------------------|
| I     | 0.8–1.0              | 121 °C      | Normal compaction         | Normal compaction                        | Normal compaction         |
| II    | 1.0–1.6              | 143 °C      | Disequilibrium compaction | Disequilibrium compaction                | Disequilibrium compaction |
| III   | 1.6–2.0              | 159 °C      | Fluid expansion           | Fluid expansion and tectonic compression | /                         |

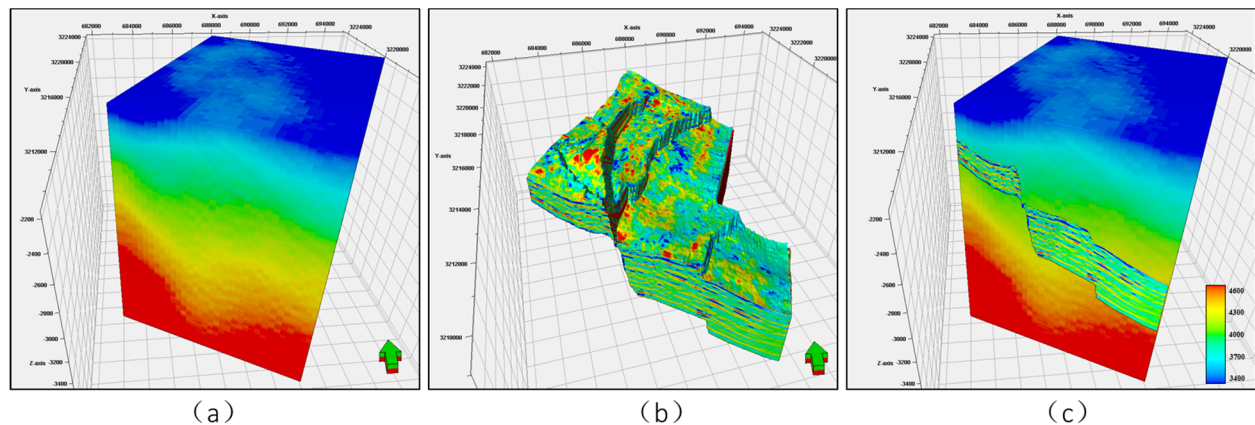
As shown in Figure 10, at 3400 m, the source rocks of the Pinghu Formation began to generate a large amount of mature oil and gas ( $RO > 0.8\%$ ), and the formation pore pressure gradually increased from normal pressure to overpressure. At 4400, some condensate natural gas ( $RO > 1.2\%$ ) was generated from the source rock while the formation pore pressure increased sharply and changed from overpressure to ultra-overpressure. This demonstrates that the fluid expansion caused by hydrocarbon is generally important for overpressure.



**Figure 10.** The measured temperature and Ro data vs. depth in the Pinghu area.

#### 4.2. Prediction of Pore Pressure with Seismic Data

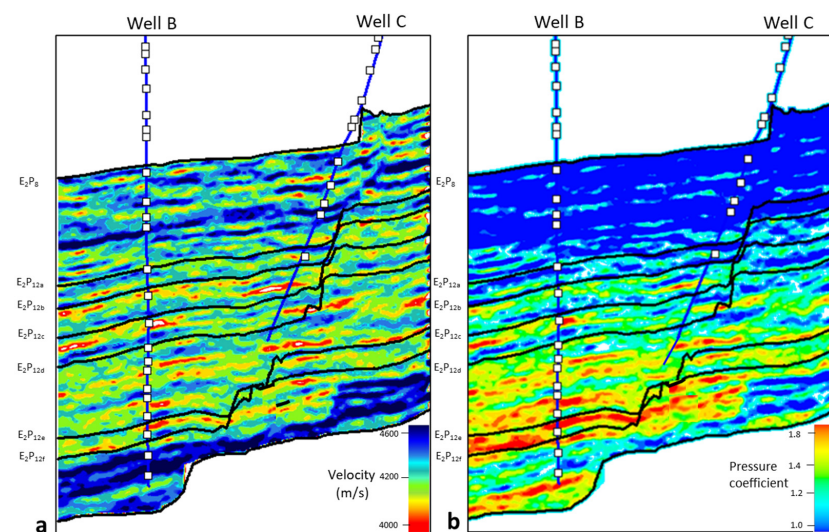
The stacked velocity spectrum during the processing of 3D seismic data in this block is  $20 \times 20$ . The stacked velocity field is interpolated and converted into layer velocity using the DIX formula. The obtained velocity field is shown in Figure 11. The DIX formula acquires the velocity. The model can reflect the trend change of velocity. However, the velocity field interpretation interval is wide when seismic data are processed, and apparent grid-like noise can be seen on the profile, which will affect the resolution of pressure prediction results to a certain extent. Pre-stack inversion can obtain velocity volume with high accuracy, but the calculation time is long, and there is no logging curve constraint in the shallow layer. Consequently, interval velocity and velocity obtained by inversion are fused into one velocity field (Figure 11c).



**Figure 11.** Velocity fields calculated by different methods. (a) The DIX formula calculates layer velocity. (b) P-wave velocity obtained from pre-stack inversion. (c) Velocity field obtained by attribute fusion.

Fluid expansion positively affects overpressure due to the plane distribution of overpressure and hydrocarbon generation intensity.

The pore pressure prediction results based on this inversion velocity field have a resolution close to that of seismic data, which provides a high-resolution data basis for three-dimensional pressure modeling (Figure 12).

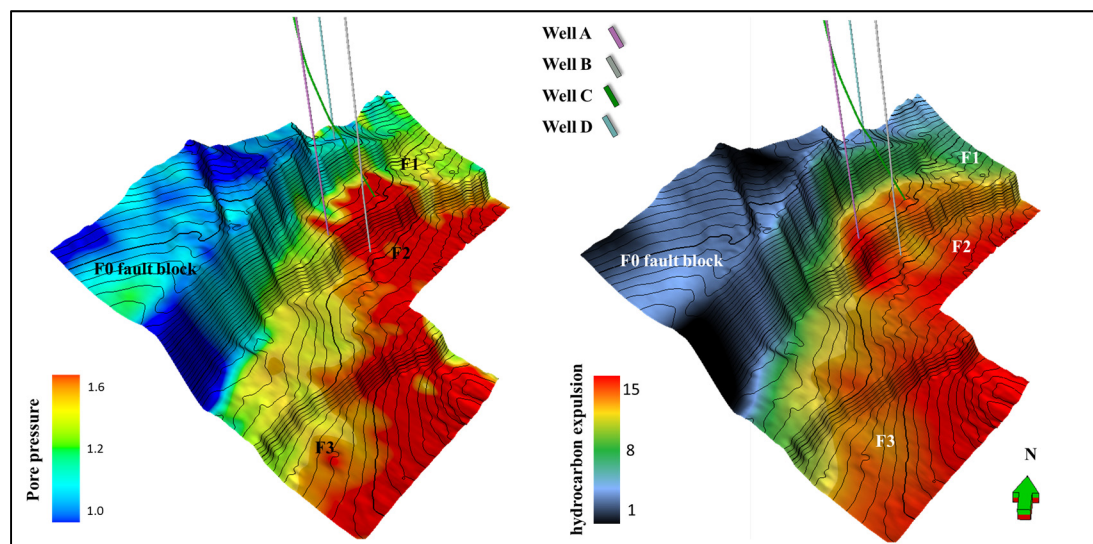


**Figure 12.** Cross-well section. (a) Velocity by seismic inversion. (b) Pressure coefficient by the Fillippone method.

## 5. Discussion

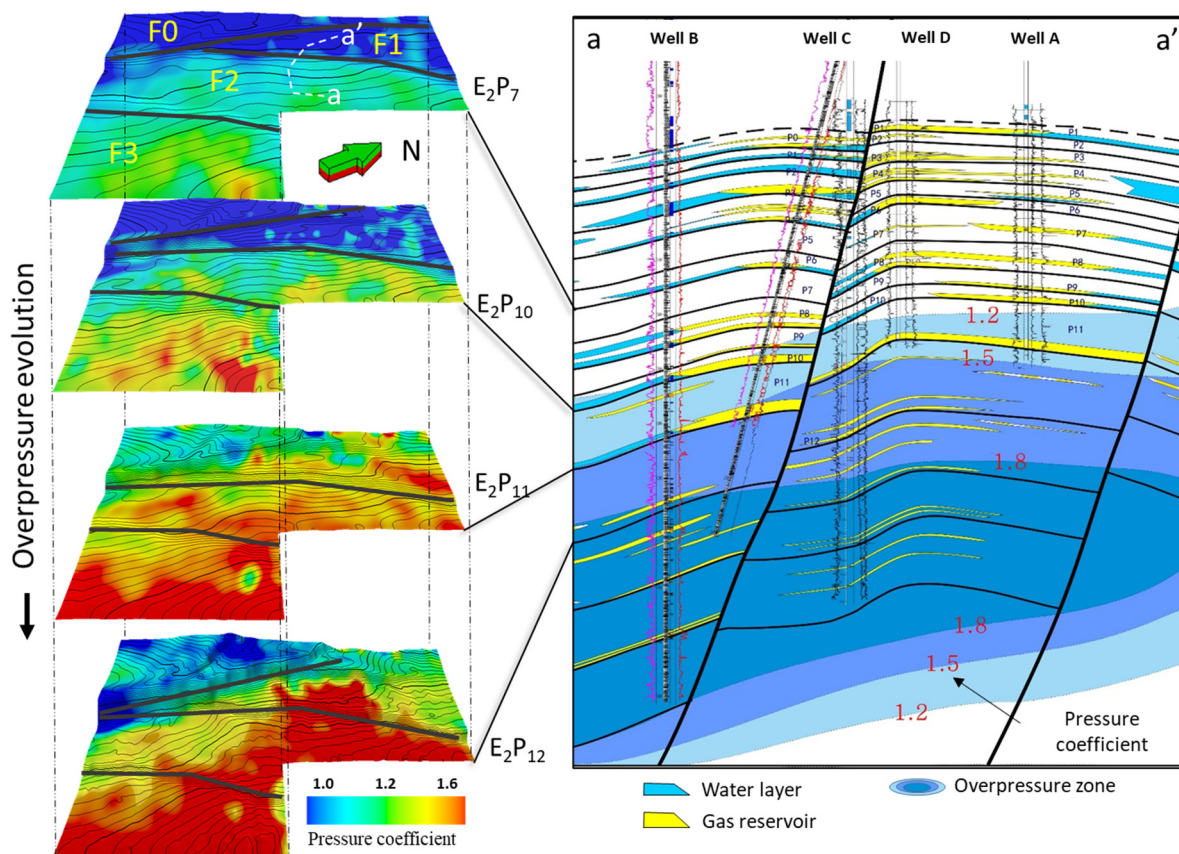
### 5.1. Overpressure Distribution in the Pinghu Field

The first part of Figure 13 shows the pore pressure coefficient at the bottom of the Pinghu Formation ( $E_2P_{12g}$ ) calculated by the Fillippone method based on the velocity field. The pore pressure increases gradually from west to east in the Pinghu Formation. The overpressure area is mainly located in F2 and F3 fault blocks in the south of the study area. The second part of Figure 13 shows the distribution of hydrocarbon expulsion intensity of the Pinghu Formation in the study area. The hydrocarbon expulsion intensity shows high distributions in the east and low distributions in the west [30]. The hydrocarbon expulsion intensity of F2 and F3 fault blocks is generally greater than  $5 \times 10^6 \text{ t} \cdot \text{km}^{-2}$ ; the hydrocarbon expulsion intensity of Well A1 reaches  $23.61 \times 10^6 \text{ t} \cdot \text{km}^{-2}$ . It is easy to observe that there is a high correlation between hydrocarbon generation intensity and overpressure distribution. The strong hydrocarbon generation of mudstone and coal seam at the bottom of the Pinghu Formation in the Pinghu field resulted in abnormally high pore pressure.



**Figure 13.** Pore pressure coefficient at P12 in the Pinghu field and Hydrocarbon-generating intensity at P12 in the Pinghu block. High pore pressure was developed in the range of high hydrocarbon ex-pulsion.

There is no abnormal formation pressure above layer  $E_2P_7$  of the Pinghu Formation. Overpressure is generated in small numbers in part of the F3 fault block in layer  $E_2P_7$ . Overpressure grew in F2 and F3 blocks in layer  $E_2P_{11}$  with a pressure coefficient between 1.2 and 1.5. Overpressure is commonly developed in layer  $E_2P_{12}$ , and the pressure coefficient is more than 1.5. With the increase in buried depth, the range of overpressure gradually increased from the footwall to the hanging wall of the fault terrace (Figure 14). The overpressure has an impact on the gas reservoir of the Pinghu Formation. The reservoir is controlled by the structure above  $E_2P_{10}$  of the Pinghu Formation, and the high part of the structure is the gas reservoir. The gas reservoir of  $E_2P_{11}$  ( $1.2 < PE < 1.5$ ) is controlled by lithology and structure, and the water layer is still located in the structure lows. The sandstone below  $E_2P_{12}$  is affected by ultra-high pressure, all of which are gas and dry layers, and there is no water layer [31,32].



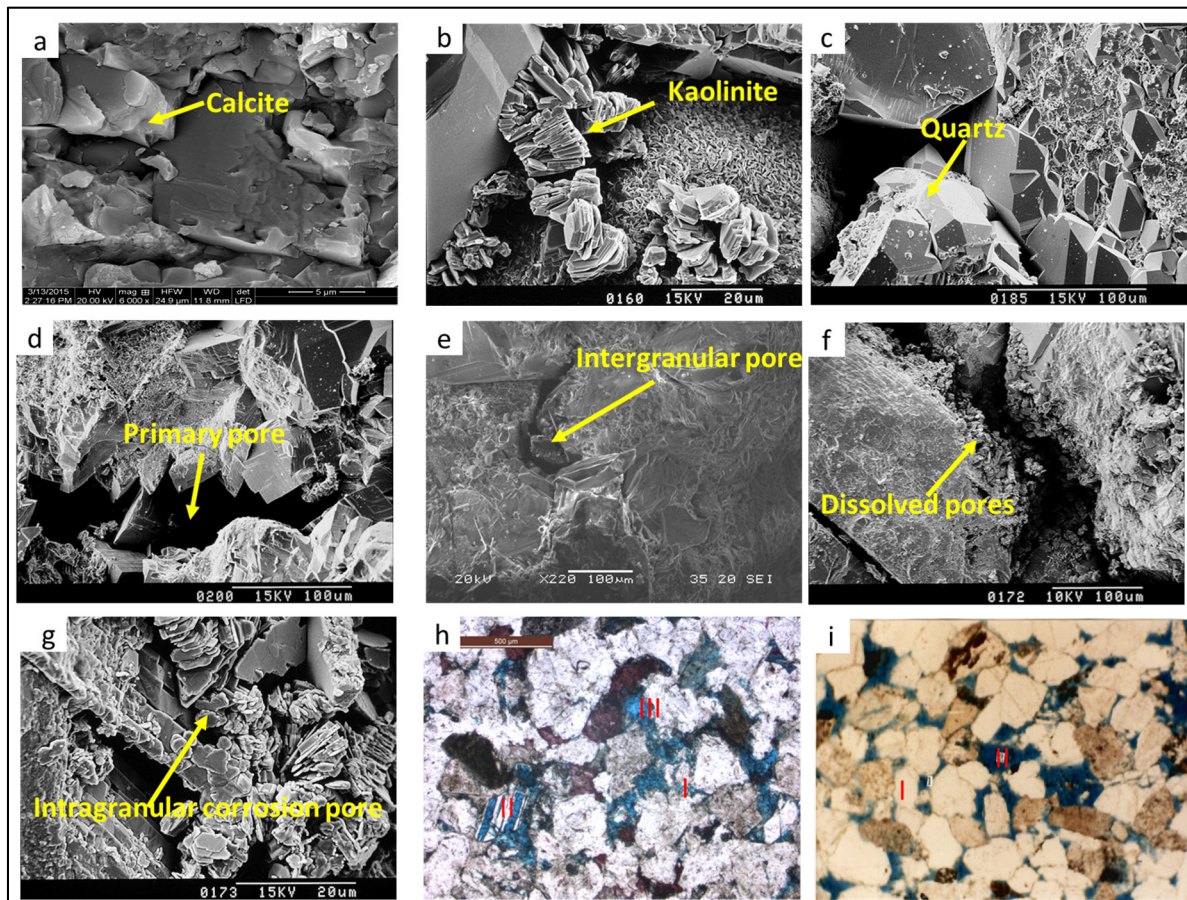
**Figure 14.** Relation between overpressure and hydrocarbon accumulation.

### 5.2. Effects of Overpressure on Reservoir

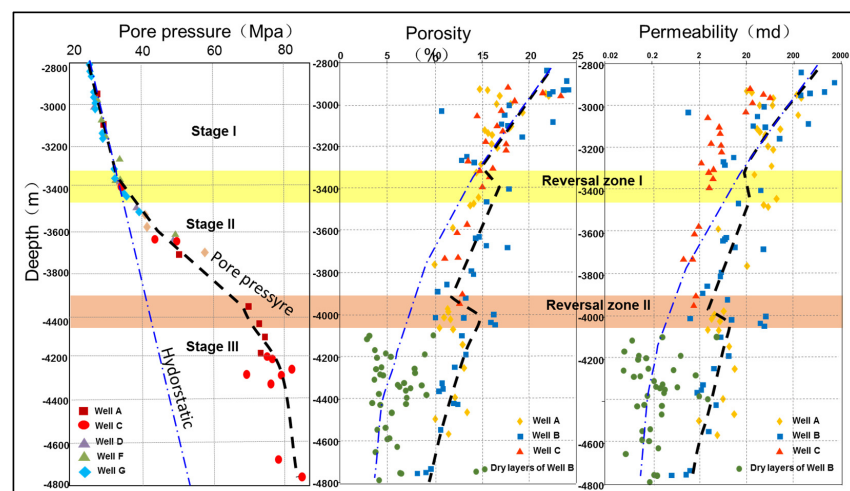
The rock is mainly composed of quartz, feldspar, and rock debris in the Pinghu Formation. The relative content of quartz is the highest, with an average of 67.6%. The average content of rock debris is 17.6%, and the content of feldspar is 16.2%. The main sandstone type is feldspathic quartz sandstone [33].

The pore type of the Pinghu Formation includes intergranular dissolved pores, intra-granular dissolved pores, mold pores, and primary pores (Figure 15) [34,35]. Intergranular dissolved pores are the most important pore type in the study area, accounting for 44%. Intragranular solution pores are mainly feldspar solution pores and rock debris solution pores, accounting for 21%. A small amount of feldspar and karst rock debris solution are affected by solid dissolution to form mold pores, accounting for 11%. The primary pores mainly exist between skeleton particles, accounting for 24%.

The physical property data of cores in the Pinghu Formation show that the reservoir porosity ranges from 2% to 25%, and the average value is 13.19%. Meanwhile, the permeability is 0.02–1700 md, and the average value is 43.2 md. The reservoir of the Pinghu Formation is generally of medium and low porosity and permeability type. However, there are two obvious reversals of porosity and permeability curves on the physical property logging curves of many wells. Both reversals retained reservoirs with better physical properties. For example, a desert area with suitable physical properties was found in Well C with the depth of 5106 m in the E<sub>2</sub>P<sub>12</sub> (Figure 16).



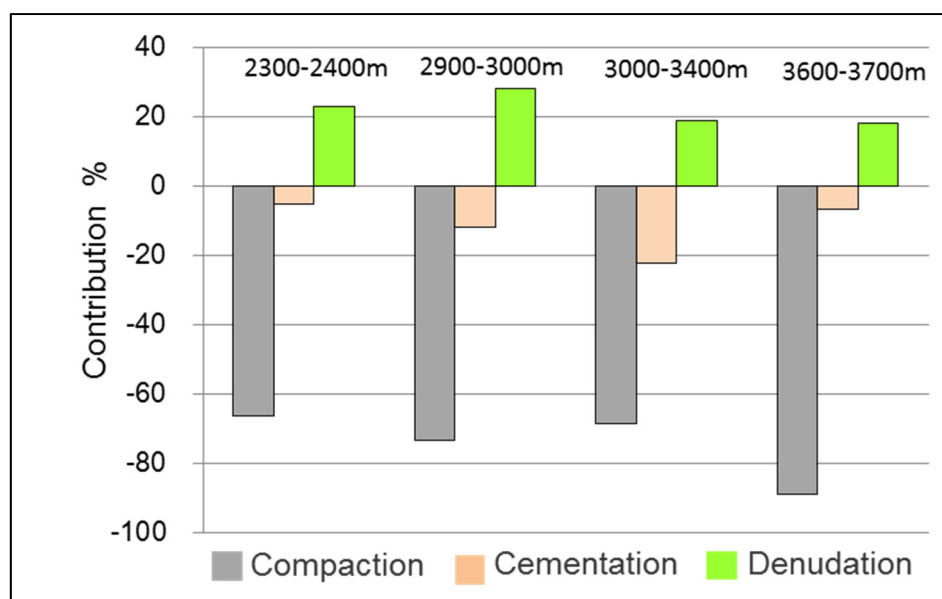
**Figure 15.** Typical images of the scanning electron microscope (SEM) and casting thin sections. (a) Calcite, Well B, 4811.76 m. (b) Kaolinite, Well D, 2931.57 m. (c) Quartz, Well D, 3402 m. (d) Primary pore, Well D. (e) There are secondary elongated pores between particles, Well D, 3693.5 m. (f) Dissolved pores in feldspar grain. (g) Mold pores filled with authigenic kaolinite, Well D, 3092.4 m. (h) I. Primary pores, II. feldspar pores, III. dissolved pores; Well B, 4794.86 m. (i) I. Primary pores, II. mold pores; Well D, 3405.29 m.



**Figure 16.** The measured pressure and porosity and permeability vs. depth in the Pinghu area. The first porosity and permeability inversion zones (yellow band) occur between 3350 m and 3450 m. The second porosity and permeability inversion zones (red bar) occur between 4300 m and 4450 m.

What is the reason for this reversal? Reservoir properties are determined by sediment and diagenesis. Sedimentary facies are not the main reason because porosity inversion occurs in wells of the Pinghu Formation with different sedimentary microfacies at the same depth. Therefore, we analyzed the contribution of different diagenesis processes to the porosity of sandstone.

On the whole, the Pinghu Formation belongs to the middle diagenetic stage A. Its destructive diagenesis is mainly compaction and cementation, and its constructive diagenesis is dissolution and hydrocarbon emplacement. Compaction is the dominant factor in porosity deterioration. As shown in Figure 17, the contribution to porosity evolution is  $-88\%$  at 3600 m, and the contribution of cementation to porosity is  $-7\%$ . Dissolution is an essential factor in improving sandstone physical properties, with a contribution of  $15\%$ .



**Figure 17.** Contribution to reservoirs porosity by compaction, cementation, and denudation in the Pinghu area.

It is found that the depths of the top of stage II and stage III in the Pinghu Formation are consistent with the depth of physical property inversion. At a depth of 3400 m, the pore pressure coefficient exceeds 1.2, while the first inversion of porosity and permeability occurs. At about 4400 m depth, the pore pressure coefficient exceeds 1.6, while the porosity and permeability are reversed for the second time (Figure 16).

On the one hand, overpressure counteracts part of the compaction and cementation of rock in the Pinghu Formation and preserves the primary pores. On the other hand, overpressure is helpful in the dissolution of soluble minerals by acidic fluid to promote the development of secondary pores.

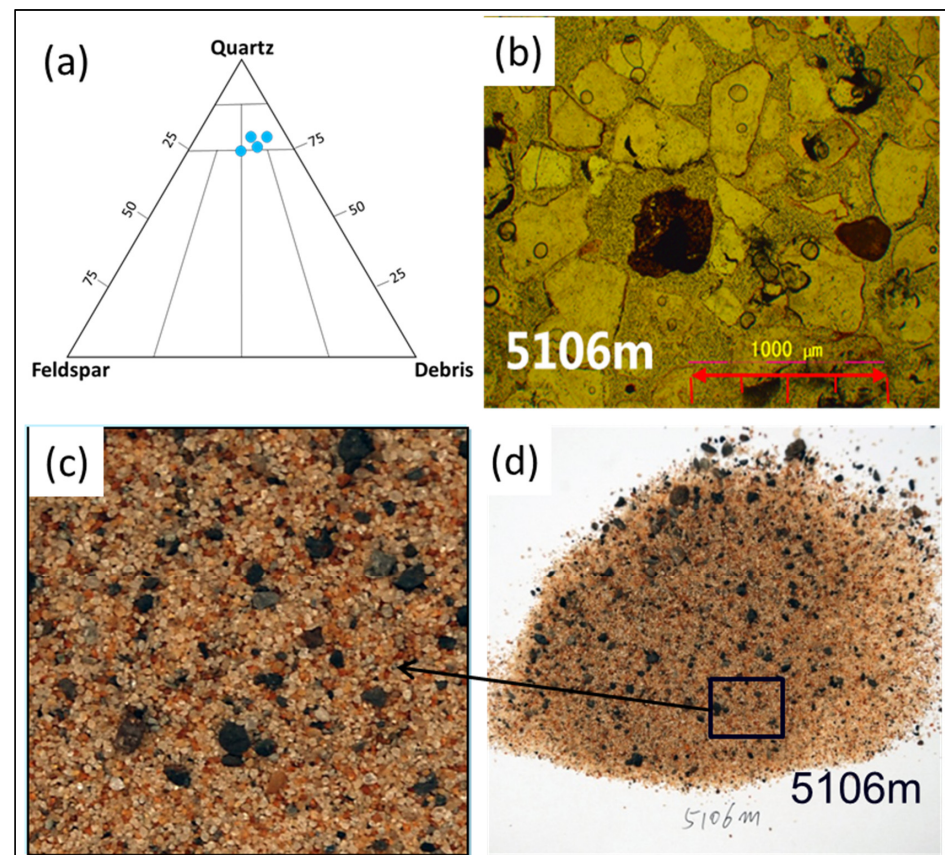
As shown in Table 2, under normal pressure, the porosity gradient decreases with a depth of  $16.5\%/1000$  m, and the permeability gradient decreases with a depth of  $753$  md/ $1000$  m. When  $1.2 < PC < 1.6$ , the gradient of porosity is  $9\%/1000$  m, and the gradient of permeability is  $66$  md/ $1000$  m. When  $PC > 1.6$ , the gradient of porosity decreasing is  $5\%/1000$  m, and the gradient of permeability is  $8.7$  md/ $1000$  m. Overpressure plays a role in reducing the gradient of porosity and permeability decreasing with depth.

**Table 2.** Pore pressure, porosity, and permeability of the Pinghu area.

| Pore Pressure |             |                |                        |                 |
|---------------|-------------|----------------|------------------------|-----------------|
| Depth range   | Value range | PC             | Deviation <sup>1</sup> | Gradient        |
| 2800–3400 m   | 22–38 Mpa   | PC < 1.2       | 0 Mpa                  | 26.7 Mpa/1000 m |
| 3400–4400 m   | 38–58 Mpa   | 1.2 < PC < 1.6 | 0–38 Mpa               | 35.1 Mpa/1000 m |
| 4400–4800 m   | 66–85 Mpa   | PC > 1.6       | 23–37 Mpa              | 15.2 Mpa/1000 m |
| Porosity      |             |                |                        |                 |
| Depth range   | Value range | mean           | Deviation              | Gradient        |
| 2800–3400 m   | 13–25%      | 17.6%          | 0–6%                   | 16.5%/1000 m    |
| 3400–4400 m   | 10–17%      | 13.5%          | 5–11%                  | 9%/1000 m       |
| 4400–4800 m   | 7–17%       | 12.5%          | 7%–10%                 | 5%/1000 m       |
| Permeability  |             |                |                        |                 |
| Depth range   | Value range | mean           | Deviation              | Gradient        |
| 2800–3400 m   | 2–1500 md   | 52 md          | 0–120 md               | 753 md/1000 m   |
| 3400–400 m    | 1–140 md    | 12 md          | 0–64 md                | 66 md/1000 m    |
| 4400–4800 m   | 0.6–120 md  | 7.2 md         | 0–2 md                 | 8.7 md/1000 m   |

<sup>1</sup> Pore pressure, porosity, and permeability of the Pinghu area. “Deviation” means the difference between an actual value and a normal trend. The normal variation trend is obtained by fitting the porosity and permeability of the samples in the normal compaction section and the dry layer samples in the overpressure section.

At 4400 m, the formation pore pressure developed from high pressure (PC > 1.2) to ultra-high pressure (PC > 1.6). Under the deep, ultra-high-pressure interface of the Pinghu Formation, there is a “sweet spot” (Figure 18), which refers to medium-coarse sandstone with permeability higher than 20 md and porosity higher than 5%.



**Figure 18.** Plots of sandstone classification and pictures of rock thin section analysis in Well C, 5106 m. (a) Plots in a triangle of Sandstone classification. (b) Analysis of Rock thin section. (c) Partial enlarged picture of debris Samples. (d) Debris Samples.

As shown in Figure 19, the results show a positive correlation between overpressure and porosity. In stage II, sandstones retained 2.2–3.9% porosity with increasing pore pressure from 34 Mpa to 64 Mpa. In stage III, sandstone retained 6–7% porosity with increasing pore pressure from 64 Mpa to 85 Mpa. Overpressure can preserve reservoir porosity. Hence, we propose an index of porosity preserving (IPP), concerning the retention value of porosity when the actual pore pressure is greater than the normal compacted pore pressure.

$$I_{PP} = (\rho_f - \rho_d) / (P_f - P_h) \quad (11)$$

where  $\rho_f$  is the porosity of sandstone affected by overpressure, and  $\rho_d$  is the porosity of dry layers.  $P_f$  is pore pressure and  $P_h$  is hydrostatic. According to the study area results, the porosity preserving index is 1.16%/10 Mpa in stage II and 1.75%/10 Mpa in stage III. The pressure coefficient of overpressure caused by fluid expansion is higher than that caused by non-equilibrium compaction, and has better pores retention effect. In addition to the influence of overpressure, permeability is greatly affected by fractures and other factors, so it is difficult to fit the approximately linear relationship with pore pressure.

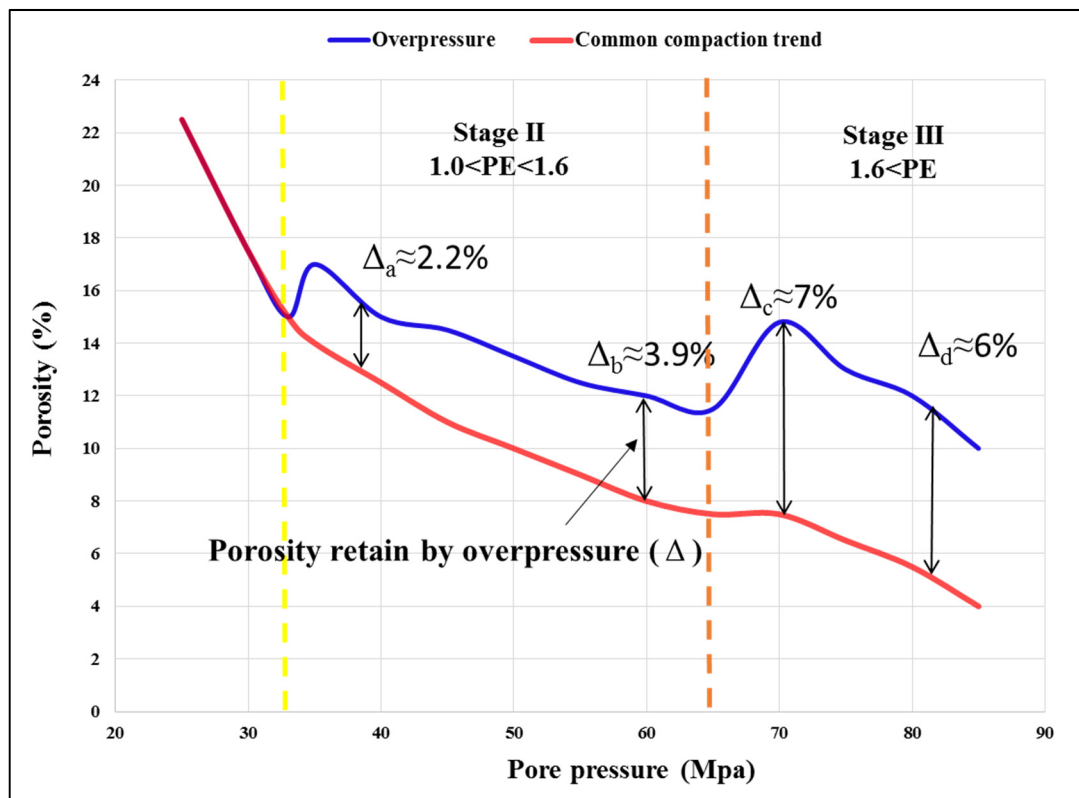


Figure 19. Quantitative analysis of the effect of overpressure on porosity.

## 6. Conclusions

In this study, we discussed the origin, prediction, and petrophysical effects of overpressure in the west slope of the Xihu Sag in the East China Sea Shelf Basin. The evolution of pressure shows three-stage characteristics in the Pinghu Formation. Stage I is normal compaction. In stage II, the overpressure is caused by disequilibrium and the pressure coefficient increasing from 1.0 to 1.6. In stage III, the overpressure is caused by fluid expansion and some structural compression with a pressure coefficient higher than 1.6.

The Fillippone method, based on the combination of raw velocity spectra and high-resolution velocity parameters obtained from seismic inversion, can be used as an effective pre-drilling pressure prediction method. The pore pressure prediction results show a high magnitude of hydrocarbon generation intensity in high overpressure in P12, which

is consistent with the hydrocarbon generation identified by adequate logs. In addition, overpressure is mainly distributed in F2 and F3 fault blocks, where sediments are easy to obtain. Therefore, disequilibrium and hydrocarbon generation may act simultaneously, but it is difficult to quantify their effects.

In this study, we quantitatively analyzed the influence of overpressure on porosity and permeability in the reservoir. There is a positive correlation between porosity and permeability with overpressure. In stage II, the overpressure generated by disequilibrium hinders the compaction and retains the primary pores. The index of porosity preserving is 1.16%/10 MPa in the second stage and 1.75%/10 MPa in the third stage.

Finally, the discovery of an overpressure reservoir at the bottom of the Pinghu Formation shows reasonable prospects for exploration and development in the deep part of the Xihu Sag. As overpressure is widely developed in the Xihu Sag, pressure prediction can be an essential supplement for reservoir development.

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