PS Model to Predict Tight-gas Sands Porosity of West Depression in Liaohe Basin, China*

Wei Wei[1], Xiaomin Zhu[1], and Yuanlin Meng[2]

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Abstract

The Eocene–Oligocene Es3 member of the Shahejie Formation in our study area is a feldspathic, debris-rich and tight gas sandstone reservoir (porosity 2.4–10.4%, permeability 0.09 - 0.38 md), a consequence of depositional attributes (grain composition, size and sorting) acted upon by diagenesis (significant mechanical and chemical compaction, precipitation of carbonate cements and authigenic clays, and deep-burial cementation by quartz) throughout the time. Considering these parameters, a comprehensive porosity prediction model is developed based on the correlation between sedimentary facies and diagenesis. The result could also provide for the exploration of other tight gas reservoir. Based on the analyses of sedimentology and petrography data of 80 cored wells, the study investigated the distribution and influences of porosity, established a model by the following steps:

(1) Diagenesis index (ID) was established integrating with temperature, Ro, quartz overgrowth, I/S, depth, and its relationship with sandstone porosity was determined to build the exponential porosity model.
(2) Sedimentary facies index (IF), which was higher in the advantageous sedimentary facies, was calculated by the distribution of porosities in different sedimentary facies during each diagenetic stage.
(3) The ultimate porosity model based on the relationship between the exponential porosity model and sedimentary facies (IF) was developed since the porosity was the cumulative effects of sedimentary facies and diagenesis.

This improved model can also restructure the evolving history of the reservoir aside from predicting present porosity. The improved model was applied to 16 wells from slope to sag throughout the field. A comparison of predicted and measured porosities showed and 1.84% average absolute error with the pore filling of 16%. This indicates the model may be used elsewhere to predict porosities. The results show that porosity decreased sharply by compaction during the early diagenetic stage. In addition, secondary porosity developed in the middle diagenetic stage A1-A2 and the reservoir became tighter with the continuous compaction alongside with quartz and carbonate cement. The reservoir in the middle diagenetic stage A1 can be described as conventional and stage A2 unconventional.

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Based on the analyses of sedimentology and petrography data of 80 cored wells, the study investigated the distribution and influences of porosity, established a model by the following steps:

1. Diagenesis index (*ID*) was established integrating with temperature, *R*o, quartz overgrowth, *I/S* and depth and its relationship with sandstone porosity was determined to build the exponential porosity model;
2. Sedimentary facies index (*IF*), which was higher in the advantageous sedimentary facies, was calculated by the distribution of porosities in different sedimentary facie during each diagenetic stage;
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HIGHLIGHTS

- Build porosity model about diagenetic index, a function of T, R_o, Vq, I/S and S%;
- Build porosity model based on compaction curve of z and sedimentary facies index (IF);
- Build final porosity model about diagenetic index (ID), z and sedimentary facies index (IF);
- This model not only predicts present porosity, also reconstructs porosity history.

RESULTS

Porosity Model

Porosity model based on sedimentary

$$\Phi_{IF} = (IF \times 5.8 + 31.7) \times \exp(-0.000413124 \times z / IF)$$

Porosity model based on diagenesis

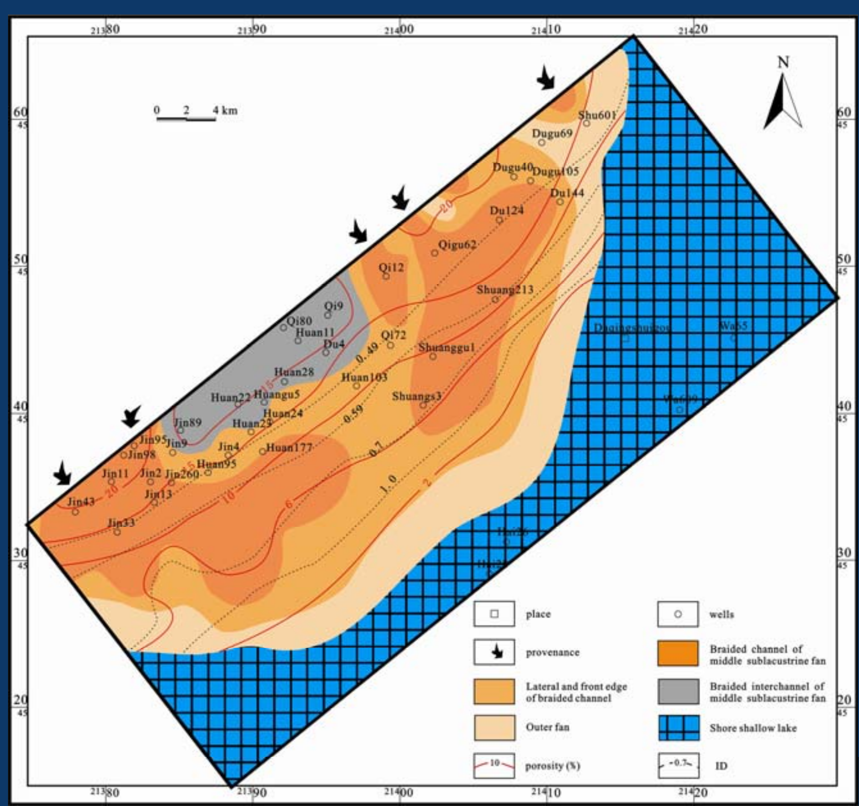
$$\Phi_{ID} = (IF \times 5.8 + 31.7) \times \exp(-3.1466 \times ID)$$

Improved porosity model:

$$\Phi = 0.57 \times \Phi_{IF} + 0.44 \times \Phi_{ID} + 0.5$$

$$\Phi = (IF \times 5.8+31.7)\times(0.57\times \exp(-0.000413124\times z/IF) +0.44\times\exp(-3.1466\times ID)+0.5$$

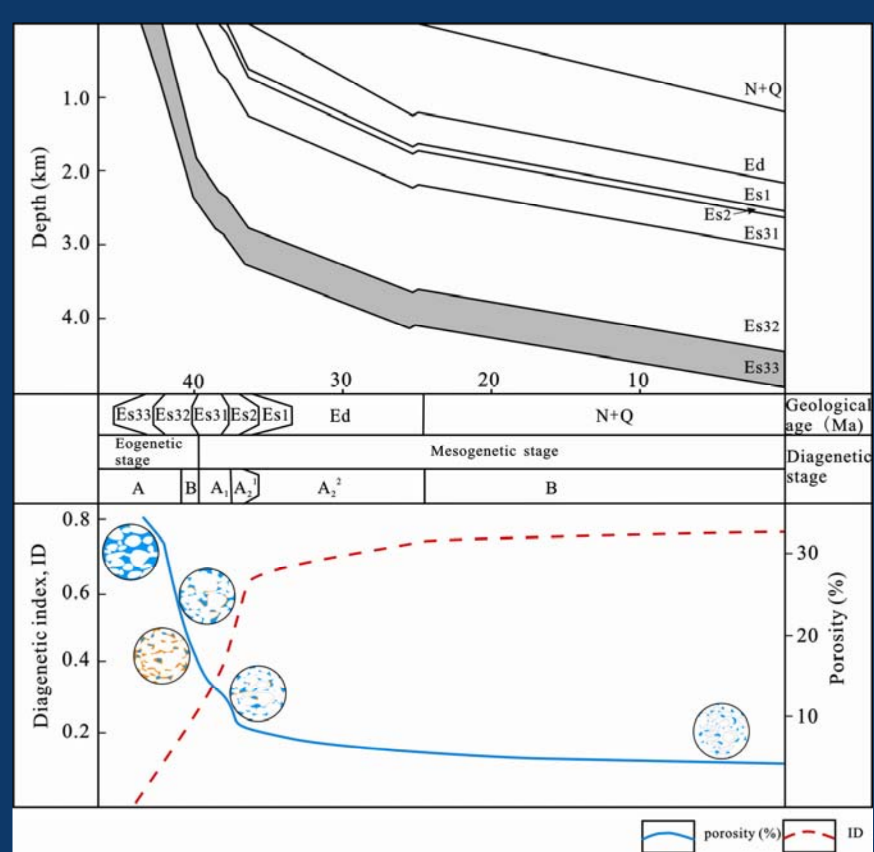
Predicted Porosity



burial depth z
+
temperature T
+
Diagenetic index ID
+
Facies index IF

Reservoir porosity

Pore evolution and diagenetic history of Es33 reservoir sandstone from well Shuangs3



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INTRODUCTION

The Liaohe Basin is located in northeast China, adjacent to Bohai Sea, and divided into several depressions such as Eastern and Western. The western depression contains Cenozoic lacustrine sediments deposited under varying water chemistries. The Eocene–Oligocene Shahejie Formation (Es) is of prime importance for petroleum exploration. Moreover, the difficulty of exploration in Shahejie Formation is increased by complex facies distributions and diagenetic alterations. In the tight sandstones, knowledge of the influence of sedimentology and paleogeography on the diagenetic patterns is also a key element for improved understanding and prediction of reservoir quality.

Significant progress has been made in recent years toward the successful application of models (e.g., Exemplar, Touchstone) to predict sandstone. However, these models are established on the basis of the sedimentary characteristics such as grain size and composition or diagenesis such as quartz overgrowth, overpressure, oil inhibition of quartz, and chlorite coatings.

RESEARCH METHOD

In this study, we have established an improved porosity model to predict porosity by analyzing the influences of sedimentation and diagenesis on porosity. Modeling processes are demonstrated as follows:

Establish diagenesis index (*ID*) the function of temperature, *R*o, quartz overgrowth, I/S, depth and time

+

Calculate sedimentary facies index (*IF*) on the basis of the distribution of porosities in different sedimentary facie during eogenetic stage, and the value of *IF* is higher in the sedimentary facies with higher porosity

↓

Build the final porosity model based on the relationship between the exponential porosity function of *ID* and the compaction curve of *IF* and depth by the linear regression method.

↓

This model could also reconstruct the porosity evolving history

GEOLOGIC SETTING

Liaohe basin is located in northeast China adjacent to the northeast of Bohai Sea (Fig. 1) and approximately 65 km in width and 470 km in length. Based on the structural position and the present distribution of oil and gas, the Liaohe Basin is subdivided into the Eastern Depression, the Damintun depression in the north, and the Western Depression. The southern part of the Western Depression is the main objective of this study.

Fig. 1

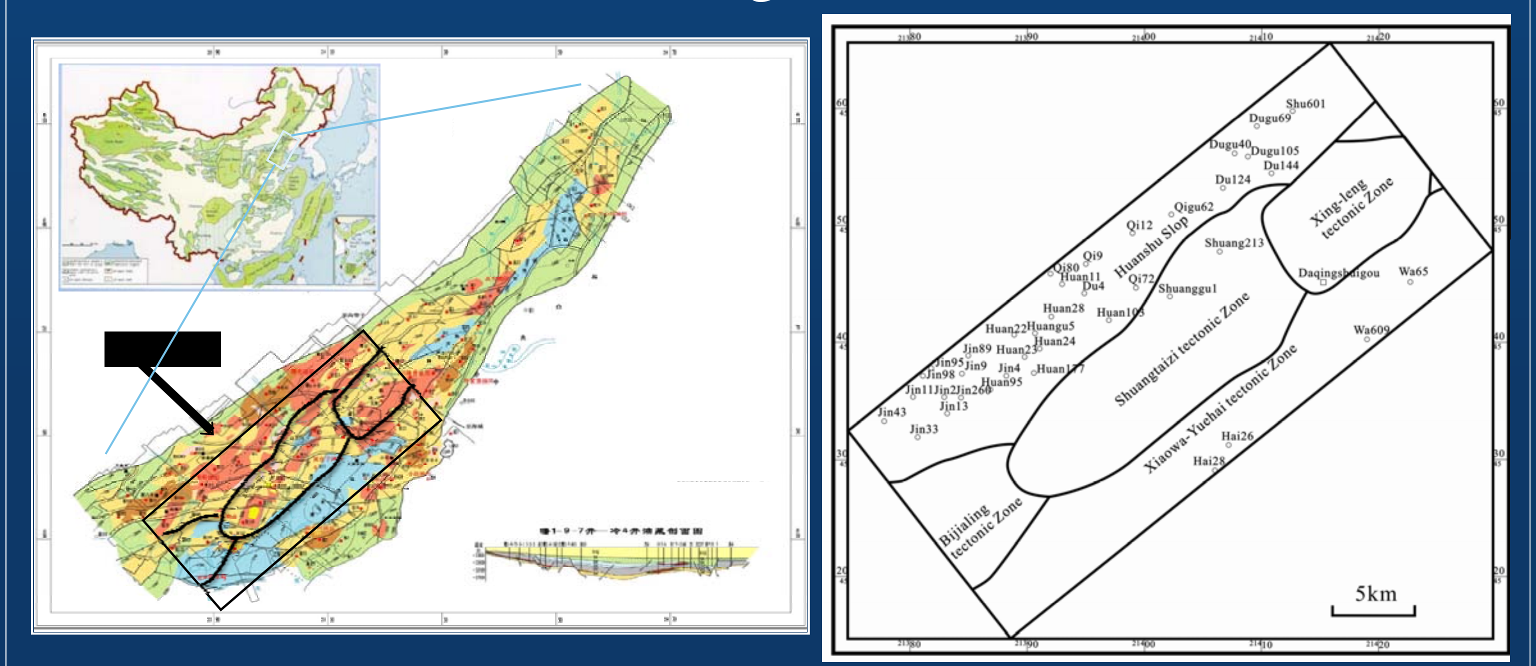
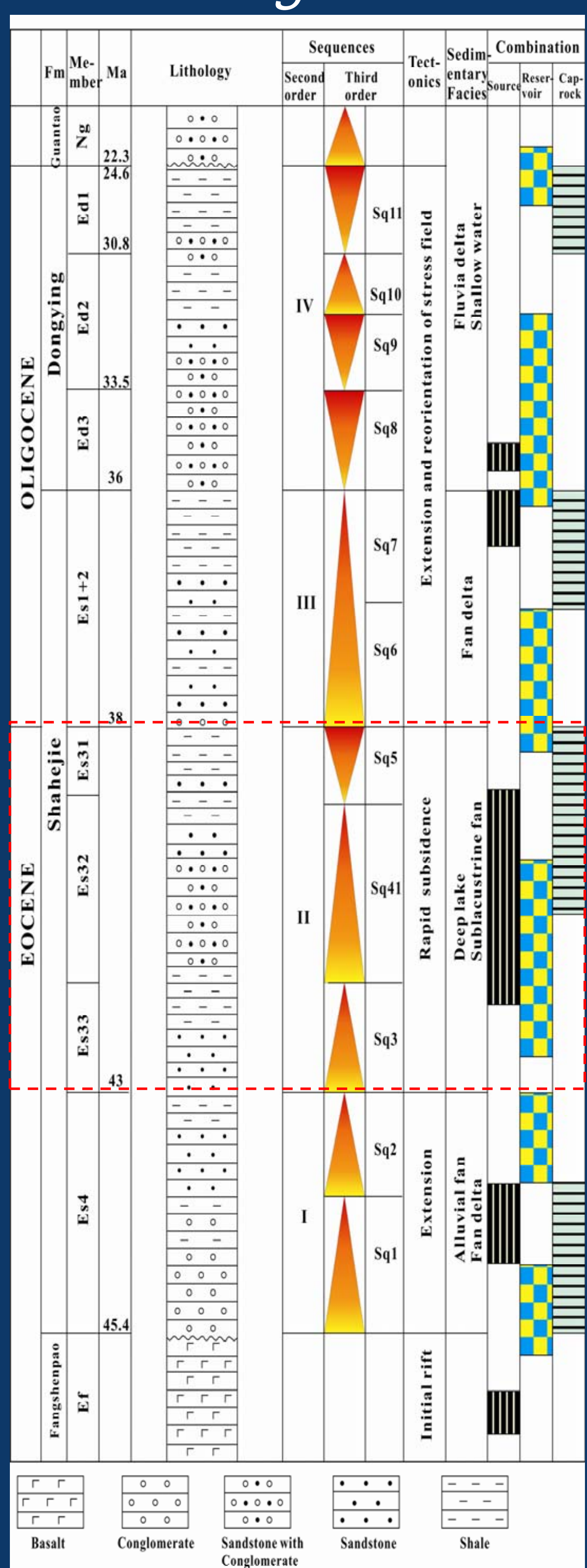


Fig. 2



Stratigraphic Column

The southern part of the Western Depression is the main objective of this study, which mainly contains Cenozoic sedimentary thickness of 3000-4000 m overlaying a Paleozoic carbonate platform (Fig. 2). Its Paleogene stratigraphic record consists of, in ascending order, Fangshenpao Fm. (Ef), Shahejie Fm. (Es) and Dongying Fm. (Ed)

Generalized stratigraphic column showing the lithology, tectonic history, sequences, sedimentary facies and source-reservoir-seal combination of the study area

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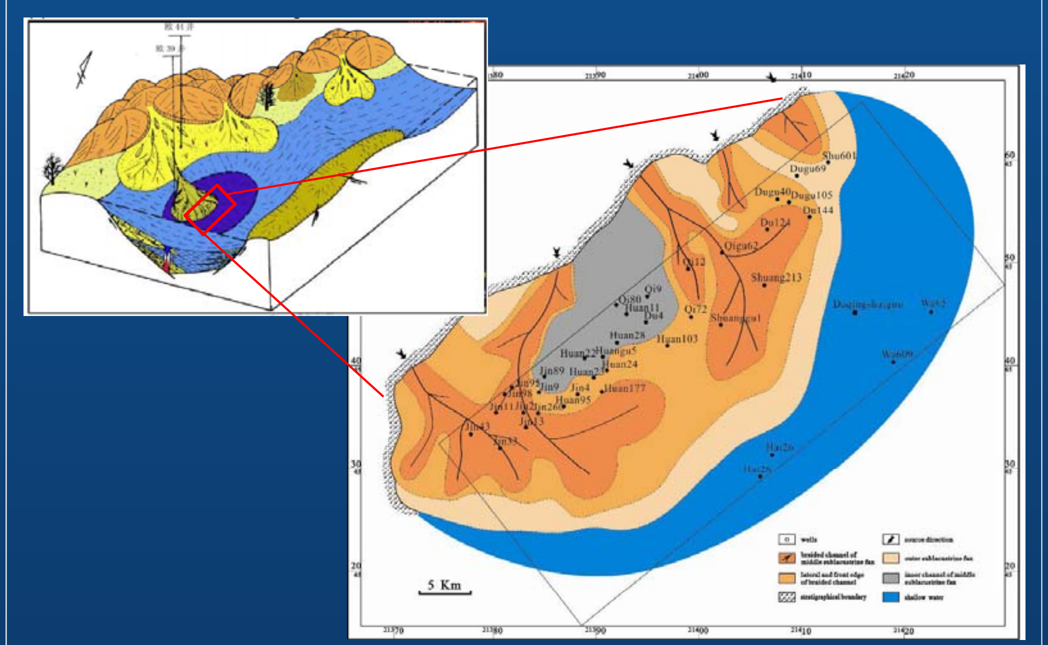
Sedimentary Facies

Sublacustrine fans within Es3 are the most typical depositional system in a deep-water setting (Fig. 3).

Fig. 3



Depositional environment exerted an essential control on the composition (Fig. 4) and texture of the sandstones (Fig. 5), influencing subsequent diagenesis and quality.

Fig. 4

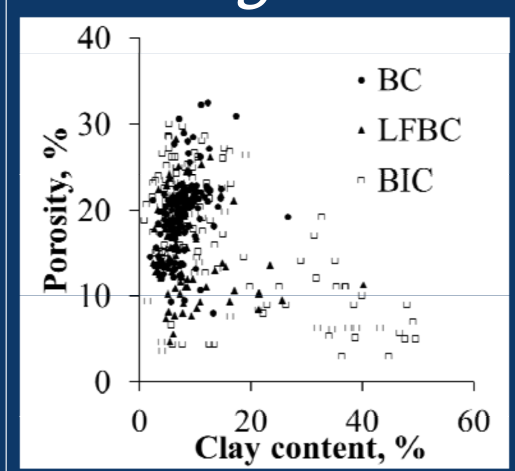
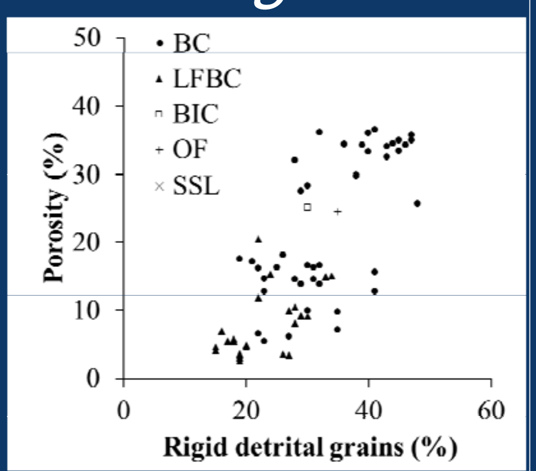


Fig. 5



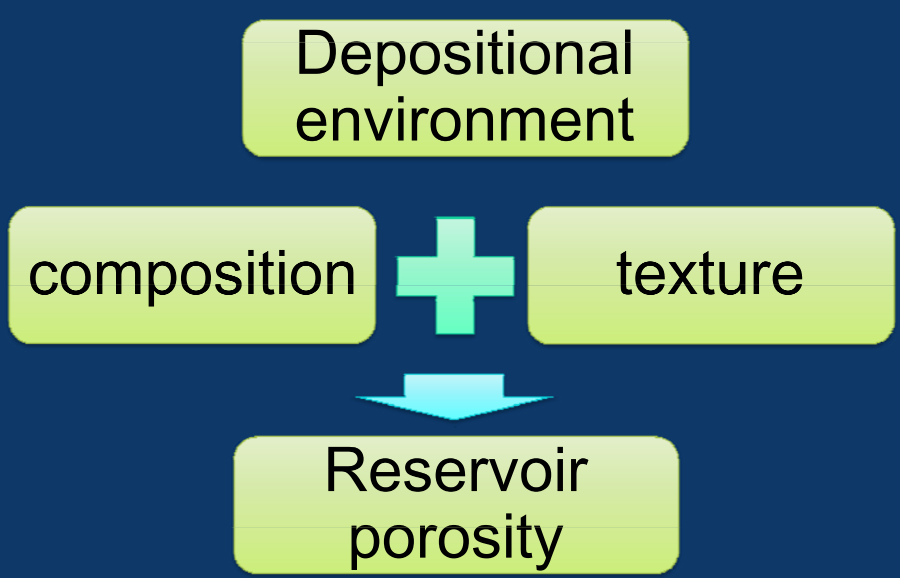


Table 2

Reservoir character-istics	BC	LFBC	BIC	OF
lithology	sandy conglomerate	sandstone	siltstone, mudstone	siltstone
rigid grain content	34.15(44) 19-48	25.7(35) 15-48	12	8
Clay matrix content	3.97(39) 1-8	6.6(67) 1-45	15.8(6) 2-45	/
median grain diameter	0.28(302) 0.016-1.31	0.34(122) 0.023-1.573	0.35(132) 0.03-1.54	/
sorting coefficient	1.65(274) 1-3.14	1.7(117) 1.35-3.02	1.78(128) 1.26-3.5	/
porosity	18.33(2412) 1.4-38.4	16.21(24) 1.2-37.4	15.3(916) 2.7-34	12.8(7) 8.3-26

Diagenetic Stage

The assessment of diagenetic level in Es3 reservoir was divided into eogenetic and mesogenetic stages (Table 2). The diagenetic strengthen increases with burial depth.

Table 2

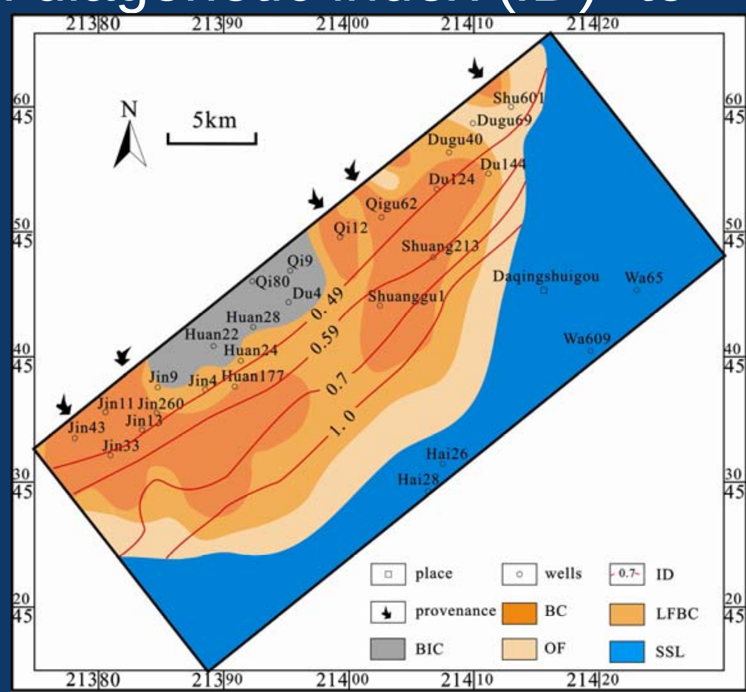
Diagenetic Stage: Stage	Period (sub-Period)	Diagenetic Facies	ID	Paleo-temp (℃)	Organic Matter: Ro (%)	Organic Matter: SI	Mudstone: S (%) in I/S	Formation Water Organic Acids	V_q (%)	Smectite	Andreattite	Kaolinite	Illite	Chlorite	Feldspar Increases	Calcite	Fe Calcite	Dolomite	Ankerite	Dissolution	Contact Type	Major pore type	Depth (m)
Early Diagenetic	A	Early Compaction	0.2	65	0.35	0.05	85		2.3												Point	Primary Pore	1390
	B	Early Cementation	0.3	85	0.5	0.25	45		3.0													Primary — Secondary Pore	2840
Middle Diagenetic	A1	Early Dissolution	0.49	94	0.7	0.52	30		4.2												Line — Point		3590
	A21	Middle Dissolution	0.59	114	1.0		26		5.8												concave-convex — Line		4180
	A22	Late Dissolution	0.7	140	1.3		15		7.7													Secondary Pore — Crack	4560
	B	Late Cementation	1.0	175	2		<15		11.7														>4560

Diagenetic Modeling System (DMS)

Diagenetic Modeling System (DMS) is a software based on the Petromod-IES, originally developed by Dr. Meng Yuanlin, to realize the numerical simulation of diagenesis and diagenetic process.

Based on the burial history reconstructing, the variations of paleogeotemperature (T), vitrinite reflectance (R_o), sterane isomerization index SI (C29 S/S+T), smectite content in I/S of clay mineral (S%) and authigenic quartz (V_q%) with geological time are simulated by the software DMS and are combined to establish diagenetic index (ID)- to reflect the diagenetic strength:

$$I_D = \sum_{i=1}^{n} P_i \times Q_i / \max Q_i$$



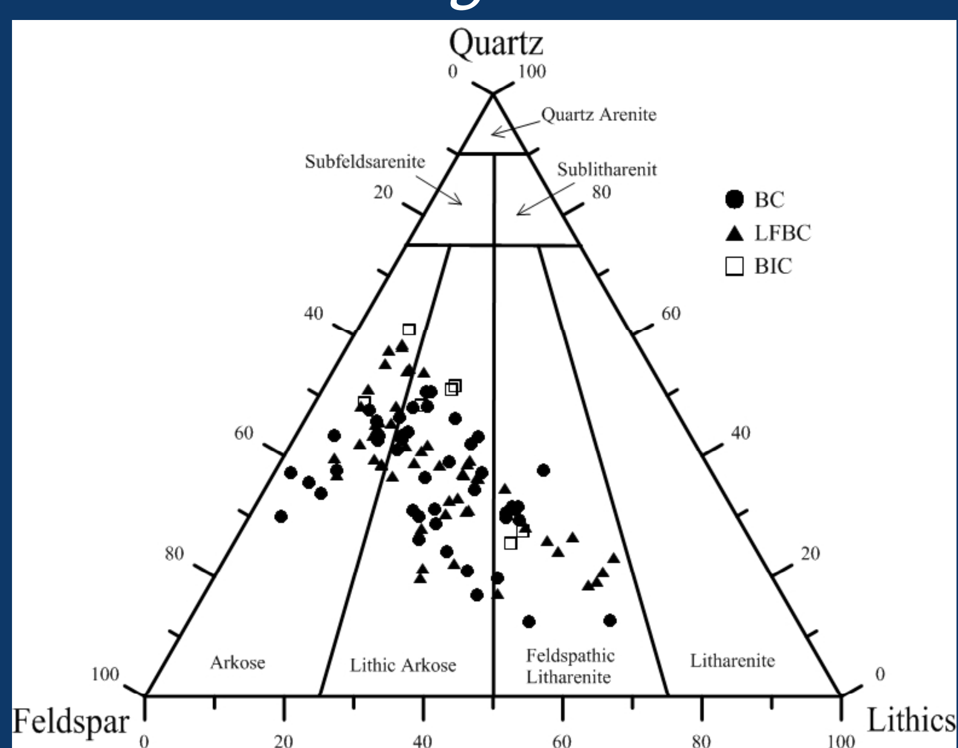
Where, I_D is diagenetic index; n is the number of diagenetic parameter, n=5; Q_i is the calculated result of the (i)th diagenetic parameter, (i.e. T); maxQ_i is the maximum value of the (i)th diagenetic parameter in the late middle B diagenetic stage.

RESULTS

Reservoir Lithology

Es3 reservoir rocks are mostly lithic arkose with subordinate feldspathic litharenite and arkose (Fig. 6).

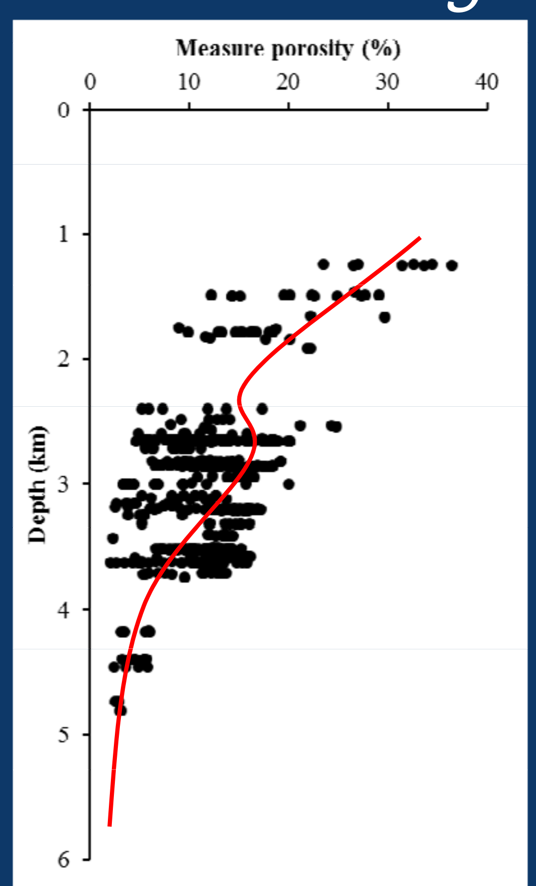
Fig. 6



Reservoir Porosity

Porosity tended to decrease with increasing depth and appeared to be depth controlled with three zones from top to bottom (Fig. 7).

Fig. 7



Depth	Porosity
<2250m	20.7%
2250-3900m	11.64%
>3900m	4.24%

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DISCUSSION

Influence Factors of Porosity

Table 3. The average porosity of each sedimentary facies in each diagenetic stage.

Diagenetic Stage	Sedimentary Facies	Average Porosity (%)
Eogenetic stage A	BC	26.1(126)/5-36.8[a]
	LFBC	20.15(2)/18.15-21.8
	BIC	19.1(3)/10.1-33.3
Eogenetic stage B	BC	24.7(410)/6.3-38.4
	LFBC	22.3(168)/4.5-35.7
	BIC	21.4(124)/4.1-34.1
	OF	12 (1)/12
	SSL	7 (1)/7
Mesogenetic stage A1	BC	15.1(1341)/1.4-37
	LFBC	13.9(651)/1.9-37.4
	BIC	12.34(55)/2.7-20.9
	OF	11.27(510)/8.3-26
	SSL	5.4(3)/4.9-5.7
Mesogenetic stage A2	BC	9.95(43)/4.3-15.5
	LFBC	3.8(12)/1.2-6.1
Mesogenetic stage B	BC	6.3(2)/6.2-6.4
	LFBC	4.1(15)/2.4-5.8

a: 26.12(126)/5.9-36.8: av.Φ(count number)/max.Φ-min.Φ

The sedimentary facies index (*IF*) was established to quantify the influence of sedimentary facies:

$$IF = \Phi_i / \Phi_{max}$$

IF of BC, LFBC, BIC, OF, SSL is 1, 0.9, 0.87, 0.48, 0.28.

Porosity Model Based on Sedimentary Facies

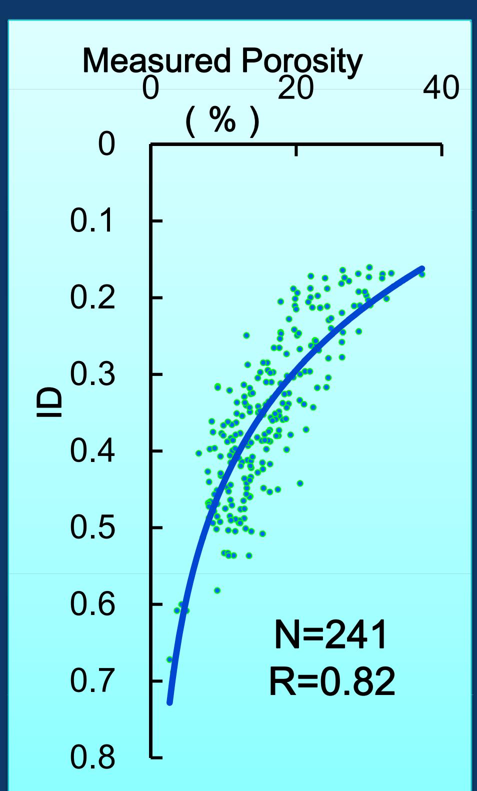
Primary porosity:

$$\Phi_0 = IF \times 5.8 + 31.7$$

Porosity model about IF:

$$\Phi_{IF} = (IF \times 5.8 + 31.7) \times \exp(-0.000413124 \times z / IF)$$

Fig. 8

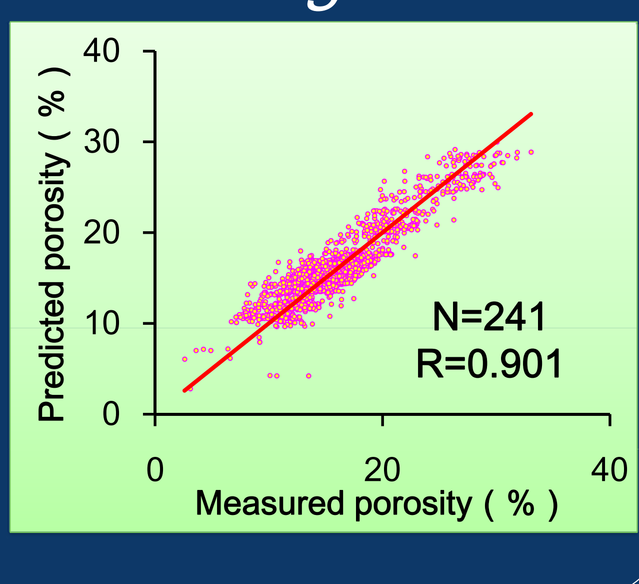


Porosity Model Based on Diagenesis

Porosity model about ID:

$$\Phi_{ID} = (IF \times 5.8 + 31.7) \times \exp(-3.1466 \times ID)$$

Fig. 9



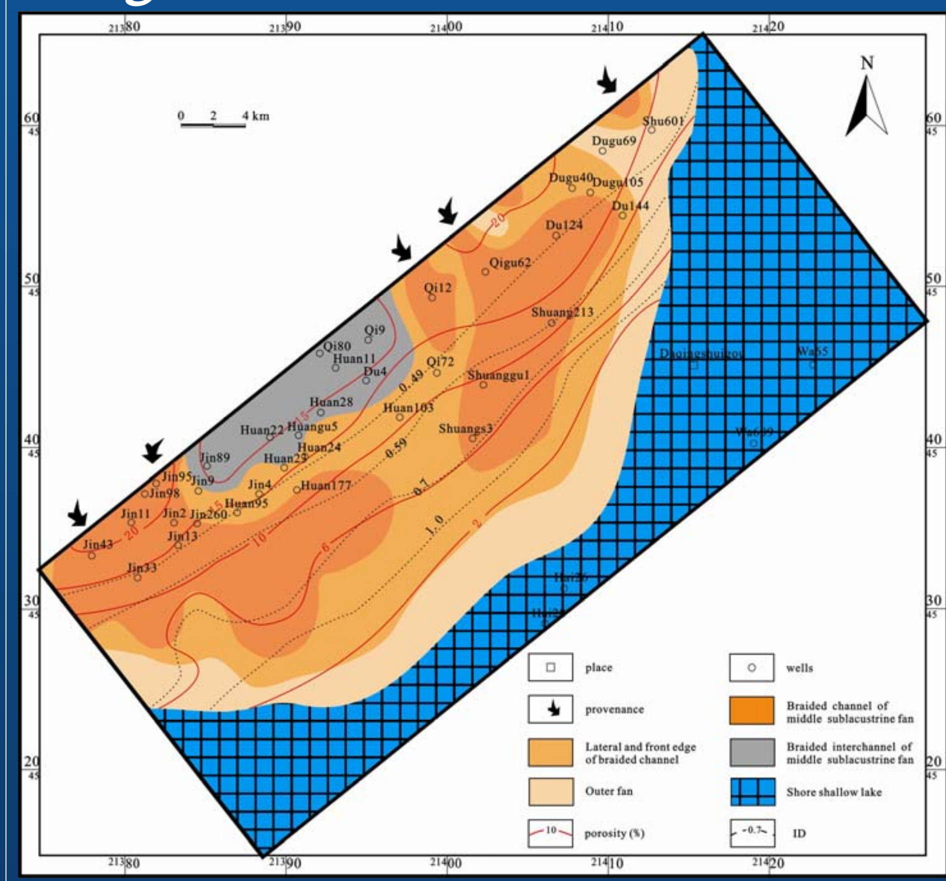
Improved porosity model

$$\Phi = 0.57 \times \Phi_{IF} + 0.44 \times \Phi_{ID} + 0.5 = (IF \times 5.8 + 31.7) \times (0.57 \times \exp(-0.000413124 \times z / IF) + 0.44 \times \exp(-3.1466 \times ID) + 0.5$$

APPLICATION

Current Porosity Prediction

Fig. 10



Burial depth *z*
+
Temperature *T*
+
Diagenetic index *ID*
+
Facies index *IF*

↓

Reservoir porosity

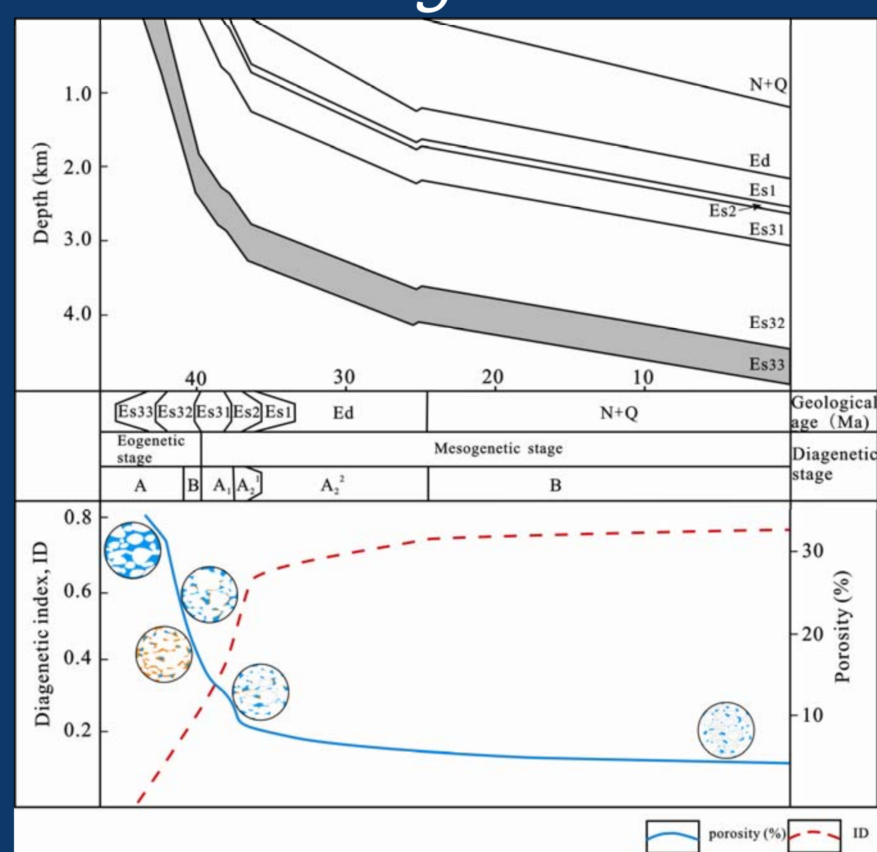
Porosity Evolution History

Diagenetic Modeling System (DMS) → burial depth *z* + temperature *T* + Diagenetic index *ID*

Facies index *IF* kept constant during geological time

→ Reservoir porosity history

Fig. 11



Porosity evolution	
Rapid decline 43–39 Ma	30% to 14%
Slow decline 39–36 Ma	14% to 8%
Stable decline 36 Ma to present	8% to 4.8%

CONCLUSION

1. The improved porosity model is established by using burial depth (*z*), diagenesis (*ID*) and sedimentary facies (*IF*).
2. The predicted porosity of Es33 decreases with increasing ID from basin boundary to basin center.
3. Porosity evolution history of Es33 reservoir are divided into three stages: the rapid decline stage during deposition of Es33 and Es32 (30 -14%), the slow decline stage during deposition of Es31 (14 - 8%), and the stable decline stage during the deposition of Neocene and Quaternary sediments (8 - 4.8%).

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Porosity model based on diagenesis

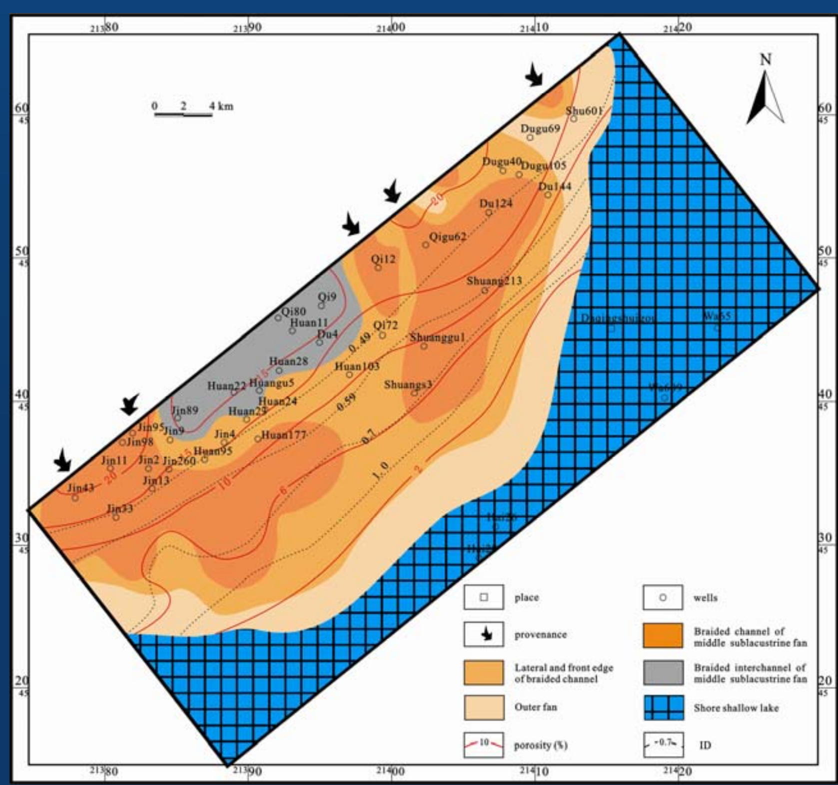
$$\Phi_{ID} = (IF \times 5.8 + 31.7) \times \exp(-3.1466 \times ID)$$

Improved porosity model:

$$\Phi = 0.57 \times \Phi_{IF} + 0.44 \times \Phi_{ID} + 0.5$$

$$\Phi = (IF\times5.8+31.7)\times(0.57\times \exp(-0.000413124\times z/IF) + 0.44\times\exp(-3.1466\times ID)) + 0.5$$

Current Porosity Prediction



Burial depth z
+
Temperature T
+
Diagenetic index ID
+
Facies index IF

Reservoir porosity

Porosity Evolution History

Diagenetic Modeling System (DMS)

Burial depth z
+
Temperature T
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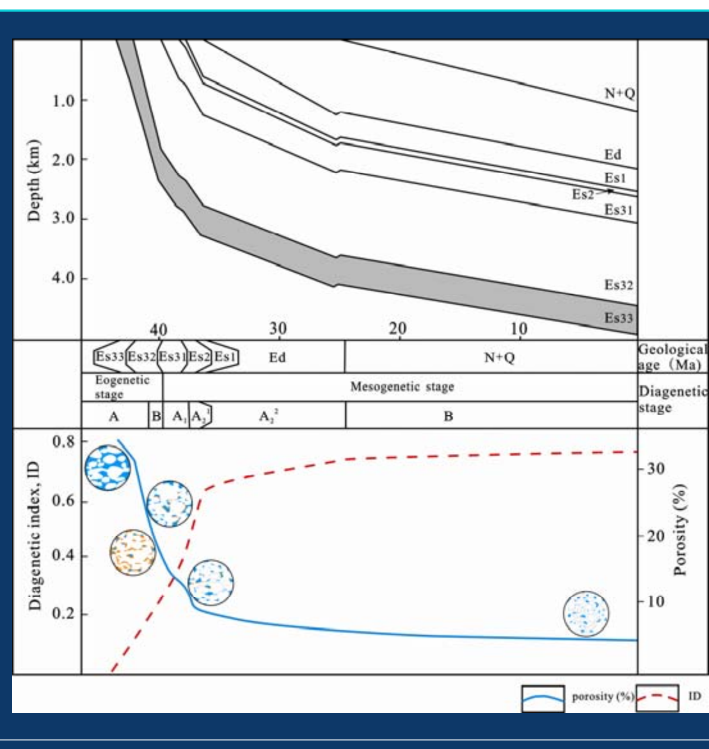
Diagenetic index ID

Facies index IF kept constant during geological time

Reservoir porosity history



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CONTACT

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If you are interested in my work, if we have the same research, please contact me.