

Reevaluation of the porosity measurements under different confining pressures: A better appraisal of reservoir porosity

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2	appraisal of reservoir porosity
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12	
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21

22 Abstract

23 Porosity is one of the most important rock properties in describing hydrocarbon 24 reservoirs. Tests on core samples provide direct and representative porosity data and the measurement of porosity at high confining pressures is recognized to correlate well with 25 subsurface reservoir porosity. Whereas theoretical deductions of the changes and 26 relationships of pressures, volumes, and compressibility suggest that porosity is reduced 27 during the coring and lifting processes, the porosity measurement at elevated confining 28 pressure does not evaluate original reservoir porosity. This theory is quantitatively validated 29 by repeated laboratory experiments of loading and unloading on sandstone core samples. 30 31 When the in-situ confining pressure is approximately 30-35 MPa (4350-5076 psi), coring and lifting would cause a porosity reduction of approximately 1.2%~1.6%, and the porosity test 32 under high confining stress results in further porosity loss. A revised approach in calculating 33 34 reservoir porosity from cored samples is proposed and can have significant implications for reserve calculations, recovery factors, and geostatistical reservoir models. The study is 35 important for both conventional and unconventional reservoirs as it discusses a fundamental 36 mechanism of porosity change. 37

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39

40 **1. Introduction**

Porosity is an intrinsic property of reservoir rocks and indicates the storage capacity
of the reservoir (Amyx et al., 1960; Jaeger et al., 2009; Schön, 2015). It is used as a primary
indicator of reservoir quality to calculate hydrocarbon volume in place, and recoverable
reserves (Pirson, 1977; D'Heur, 1984; Halvorsen and Hurst, 1990; Terry and Rogers, 2014).
Petrophysicists use core porosity values to help calibrate porosity derived from well log data.
Porosity is routinely obtained from core tests and well log interpretations, of which tests of

47 carefully selected core samples can provide direct and representative porosity data for 48 subsurface reservoir evaluations (Pirson, 1963; Serra, 1983; Hearst and Nelson, 1985; Ellis 49 and Singer, 2007; Civan, 2015). Porosity is determined by measuring the bulk volume, grain volume, and pore volume of core samples (Keelan, 1972, 1982; Hensel, 1982; Luffel and 50 Howard, 1988; Hook, 2003; Honarpour et al., 2005). The most common porosity 51 measurement directly uses Boyle's Law method: The gas transfer technique involves the 52 53 injection and decompression of gas (He, CO₂, or N₂) into the pores of a fluid-free (vacuum), dry core sample; either the pore volume or the grain volume can be determined, depending 54 upon the instrumentation and procedures. The measurement could be done either under low 55 confining stress, or elevated confining stress which is representative of the reservoir effective 56 stress conditions. It has been suggested that measurements at elevated confining stress more 57 closely represent original reservoir porosity than measurements at zero or low confining 58 stress (Nieto et al., 1994; American Petroleum Institute, 1998; Helle et al., 2001; Holt et al., 59 2003; McPhee et al., 2015). Porosity obtained at ambient condition is thought to be higher 60 than original reservoir porosity as the pore volumes expand when the confining pressure is 61 reduced. In oilfields when core is taken across the reservoir interval the oil tends to flow out 62 of the oil-containing cores shortly after the coring and prior to lifting. This phenomenon 63 occurs because the pressure outside of the core is lower than the pressure within the rock, and 64 the pressure difference causes fluid expansion and possible pore space shrinkage, i.e. oil 65 actively flows out (fluid expansion) and passively "squeezed out" (pore-space shrinkage). 66 67 This discrepancy provokes a reevaluation of porosity changes throughout the stress variations. 68

In this paper, theoretical and experimental analyses are undertaken to appraise how
porosity will change with differing confining pressures, volumes, and compressibilities.
These changes are physically modelled and a new model is presented to better understand

72 how porosity changes with differing physical states and provide an improved quantitative approach to how core porosity may change with ambient conditions. 73

74 2. Theoretical deduction of porosity changes through coring to lifting

Porosity is the fraction of the volume of pores over the total volume of a rock 75 (Equation 1), and the bulk volume (V_b) of a rock consists of the pore volumes (V_P) and rock 76 matrix volumes (V_r) (Equation 2). Porosity change is the elastic volumetric response of 77 78 porous media to variations in stress, i.e. the change in pore volume relative to bulk volume in a sample (Fatt, 1958; Brown and Korringa, 1975; Zimmerman et al., 1986; Zimmerman, 1990; 79 80 Berryman, 1992; Berge, 1998).

81

93

(2)

(1)

The pressure or stress imposed on a layer of soil or rock by the weight of overlying 83 material is defined as overburden pressure, also called lithostatic pressure, confining pressure 84 or vertical stress (Fatt, 1953; Dobrynin, 1962). Pore pressure is the pressure of a fluid at some 85 point within the pore system, also called fluid pressure, formation pressure, or reservoir 86 pressure (Dickinson, 1953; Eaton, 1972). The overburden pressure (σ) and pore pressure (P) 87 88 acting on the cored sandstone sample keeps decreasing through the coring and lifting process. When P and σ changes, the $-d\bar{\sigma}$ acts on the whole rock while the -dP acts on the pore 89 90 volumes. According to Betti's reciprocal theorem and applications (Betti, 1872; Laurent et al., 91 1993; Cheng, 2014), the total work done by the forces in three dimensions equals 0 in the 92 balance state (Equation 3):

$$d\bar{\sigma}(\frac{\partial V_b}{\partial P})_{\bar{\sigma}}dP + dP\left(\frac{\partial V_P}{\partial \bar{\sigma}}\right)_P d\bar{\sigma} = 0$$
(3)

95
$$\left(\frac{\partial V_b}{\partial P}\right)_{\overline{\sigma}} = -\left(\frac{\partial V_P}{\partial \overline{\sigma}}\right)_P \tag{4}$$

(5)

Compressibility is introduced to quantify the ability of a soil or rock to reduce in 96 97 volume under applied pressure (Brace, 1965; Brown and Korringa, 1975; Zimmerman et al., 1986). Given the overburden pressure and pore pressure conditions, the changes of porosity 98 during coring and lifting can be studied by analyzing the compressibilities of the rock (core), 99 rock matrix, and pores. The $(\overline{\sigma} - P)$ is set stable when determining the compressibilities (5): 100

101
$$d\bar{\sigma} = dP$$

In a homogenetic core sample, the relationship between rock matrix compressibility 102

 (C_r) and the changes of volumes is as in Equation 6: 103

104
$$\frac{dV_r}{V_r} = \frac{dV_b}{V_b} = \frac{dV_P}{V_P} = -c_r d\bar{\sigma} = -c_r dP \tag{6}$$

105

As the V_r , V_b , and V_P are the functions of σ and P, Equation 6 can be transformed

into partial differential Equation 7: 106

107
$$\frac{1}{V_b} \left(\frac{\partial V_b}{\partial \bar{\sigma}}\right)_P d\bar{\sigma} + \frac{1}{V_b} \left(\frac{\partial V_b}{\partial P}\right)_{\bar{\sigma}} dP = \frac{1}{V_P} \left(\frac{\partial V_P}{\partial \bar{\sigma}}\right)_P d\bar{\sigma} + \frac{1}{V_P} \left(\frac{\partial V_P}{\partial P}\right)_{\bar{\sigma}} dP = -c_r d\bar{\sigma} = -c_r dP \quad (7)$$

108 hence:

109
$$\frac{1}{V_b} \left(\frac{\partial V_b}{\partial \overline{\sigma}}\right)_P + \frac{1}{V_b} \left(\frac{\partial V_b}{\partial P}\right)_{\overline{\sigma}} = \frac{1}{V_P} \left(\frac{\partial V_P}{\partial \overline{\sigma}}\right)_P + \frac{1}{V_P} \left(\frac{\partial V_P}{\partial P}\right)_{\overline{\sigma}} = -c_r \tag{8}$$

110

111

112

113

Considering the relationships in Equations 1 and 4, the elements of Equation 8 can be exchanged as Equation 9:

$$\frac{1}{V_b} \left(\frac{\partial V_b}{\partial P}\right)_{\overline{\sigma}} = -\frac{1}{V_b} \left(\frac{\partial V_P}{\partial \overline{\sigma}}\right)_P = -\frac{\emptyset}{V_P} \left(\frac{\partial V_P}{\partial \overline{\sigma}}\right)_P \tag{9}$$

Therefore:

114
$$c_r = \frac{\phi}{V_P} \left(\frac{\partial V_P}{\partial \overline{\sigma}}\right)_P - \frac{1}{V_b} \left(\frac{\partial V_P}{\partial \overline{\sigma}}\right)_P \tag{10}$$

115 In a constant-temperature experimental condition, the pore compressibility (c_P) can be determined by either changing the confining pressure (σ) while remaining the pore pressure 116 (*P*) stable as in Equation 11: 117

118
$$c_P = -\frac{1}{V_P} \left(\frac{\partial V_P}{\partial \overline{\sigma}}\right)_P \tag{11}$$

119 or changing *P* while keeping σ stable as in Equation 12:

$$c_P = -\frac{1}{V_P} \left(\frac{\partial V_P}{\partial P}\right)_{\overline{\sigma}} \tag{12}$$

121 In reservoir condition, σ stays unchanged to the specific reservoir rock, whereas *P* 122 decreases or increases corresponding to the expulsion or injection of fluid. In this case, the 123 rock compressibility (c_b) and pore compressibility (c_P) are: 124 $c_b = -\frac{1}{V_b} (\frac{\partial V_b}{\partial P})_{\overline{\sigma}}$ (13)

$$c_P = -\frac{1}{V_P} \left(\frac{\partial V_P}{\partial P}\right)_{\overline{\sigma}}$$

126 Combining Equations 10, 13 and 14, a new relationship of the three compressibilities127 can be derived:

$$c_b - c_r = \phi c_P \tag{15}$$

129 Defining a new intermediate function (c_f) to investigate the change of porosity:

130
$$c_f = \frac{1}{\phi} \left(\frac{\partial \phi}{\partial \overline{\sigma}}\right)_P \tag{16}$$

131 Equation 16 can be transformed combining Equations 1 and 15 as:

132
$$c_f = \frac{1}{\phi} \left(\frac{\partial \phi}{\partial \overline{\sigma}} \right)_P = \frac{V_b}{V_P} \left(\frac{\partial (\phi) \frac{V_P}{V_b}}{\partial \overline{\sigma}} \right)_P = c_P - c_b = \frac{1}{\phi} \left[c_b (1 - \phi) - c_r \right]$$
(17)

133 Generally, c_b is more than ten times greater than c_r , thus Equation 17 can be 134 reformed in approximate to:

135

136

120

125

$$c_f = \frac{1}{\phi} c_b (1 - \phi) \tag{18}$$

137 A partial differential equation of porosity versus pressure can now be derived from138 Equations 16 and 18:

139 $\left(\frac{\partial\phi}{\partial\overline{\sigma}}\right)_P = c_b(1-\phi) \tag{19}$

140 The c_b of sandstones typically ranges (0.0001~0.0004)/MPa in the pressure interval 141 of 0~40 MPa (Zimmerman, 1990). Though c_b is pressure dependent, the value of c_b in

(14)

142 reservoir condition is so small that its change with pressure change becomes negligible 143 comparing to the value of $(1 - \phi)$. Thus, here it can be assumed as a very small constant.

In the process of coring and lifting the core to the surface, the confining pressure of surface and reservoir is given σ_1 and σ_2 , respectively ($\sigma_2 > \sigma_1$). The porosities of the two ends are correspondingly ϕ_1 and ϕ_2 . The integration of ϕ in Equation 19 from σ_2 to σ_1 leads to:

$$\phi_2 = 1 - (1 - \phi_1)e^{c_b(\sigma_1 - \sigma_2)} \tag{20}$$

149

As
$$\sigma_2 > \sigma_1$$
, resulting $e^{c_b(\sigma_1 - \sigma_2)} < 1$, hence $1 - (1 - \phi_1)e^{c_b(\sigma_1 - \sigma_2)} > \phi_1$

150 giving the final relationship between ϕ_1 and ϕ_2 as: $\phi_2 > \phi_1$

151 This deduction identifies that the porosity of in-situ reservoir rock is greater than the 152 porosity at the surface, i.e. the porosity reduces during the coring and lifting process.

153 **3. Experimental apparatus and procedures**

To verify the theoretical conclusion, we designed an apparatus to simulate the fluid 154 155 activity and porosity changes through loading and unloading processes. This apparatus is primarily designed to make artificial cores that resemble reservoir rocks in composition, pore 156 structure, and permeability. This apparatus comprises a high-pressure-high-temperature 157 (HPHT) pump, a control system, an incubator temperature system, a compaction cylinder, a 158 fluid expulsion acquisition system, and a data acquisition system (Figure 1). The compaction 159 cylinder is 13 cm (~5 inch) in inner diameter, thus the cores made in this cylinder are the 160 161 same size as real cores.

The experimental materials consist of 70-90 wt% matrix grains and 10-30 wt% cements. The matrix grains are river channel sand grains with the sizes of 1.0-1.2 mm, 0.55-1.0 mm, 0.50-0.55 mm, 0.43-0.50 mm, 0.38-0.43 mm, 0.27-0.38 mm 0.25-0.27 mm, 0.21-0.25 mm, 0.18-0.21 mm, 0.12-0.18 mm, 0.10-0.12 mm, 75-106 μ m, 58-75 μ m, 48-58 μ m, 45-48 μ m, 42-45 mm or 38-42 mm. The mixing and matching of these sand grains can 167 provide the grain matrix of coarse sandstone, medium sandstone, fine sandstone, etc. The cements consist of calcium carbonate (CaCO₃), magnesium carbonate (MgCO₃), ferrous 168 oxide (FeO), aluminum chloride (AlCl₃), and clay minerals, with concentrations of 3-10%, 169 2-5%, 0-3%, 0-3%, and 5-15%, respectively. The materials are representative of reservoir 170 rocks and no artificial cement is involved in the experiments. Therefore, the cements of the 171 cores made by this method are more consistent with those of the reservoir rocks than Portland 172 cements widely used in other artificial cores (Fattahpour et al., 2014; Trads and Lade, 2014; 173 Li et al., 2015). In this paper, the artificial core content is 87% matrix grains and 13% 174 cements. The matrix is mixed by 8 portions of fine-middle sand grains (0.13-0.50 mm) and 1 175 portion of silt grains (38-42 µm). The cements include 5% CaCO₃, 3% MgCO₃, and 5% clay 176 177 minerals (Figure 2).

The matrix grains, cements, and prepared formation water (containing Mg²⁺, Ca²⁺, 178 Na^+ , K^+ , CO_3^{2-} , Cl^- , OH^- and SO_4^{2-}) are blended and capsulated in the compaction cylinder 179 which is placed in the incubator. Then the temperature is set and the temperature data is 180 recorded. After the temperature stabilized, the HPHT pump starts working and pushes the 181 piston to compact the materials. When the compaction finishes, pressure is released. The 182 pressure data, including inlet pressure and outlet pressure (the confining pressure is the 183 difference between inlet pressure and outlet pressure), is also recorded. During the whole 184 experiment, the fluid expelled from the compaction cylinder is condensed, collected and 185 measured in the measuring cup on the electronic balance. Pressure and fluid expulsion data 186 187 are recorded.

Initially the temperature is set 60 °C (140 °F), and the confining pressure is 40 MPa (5800 psi). The compaction lasts 1000 min and this is defined as the first loading-stablizing stage; afterwards the temperature is lowered to room temperature and pressure is withdrawn to 0.45 MPa (65 psi), this interval is the first unloading stage; then the temperature and pressure is elevated to 40 °C (104 °F) and 30 MPa (4350 psi), respectively, which is the second loading stage; and in the last procedure, namely the second unloading stage, the temperature and pressure are brought back to room condition. The minimum measured fluid expulsion volume in this system is 0.001 ml, and the expulsion rate in our experiment ranges between 0.001-4.42 ml/min (Table 1).

197 **4. Experiment results**

Three major factors are measured in the experiments: the confining pressure, the outlet pressure, and the volume of expelled fluid. The temperature data is also recorded in the process. The whole experiment is divided into four stages according to the settings of confining pressure and temperature (Figure 3).

202 4.1. Detailed analysis of experiment results:

203 ① The first loading – stabilizing stage

At the beginning of the first loading stage the confining pressure was pumped from 204 vacuum to 27.58 MPa (4000 psi) and the vessel was heated to 40 °C (104 °F). Fluid 205 expulsion occurred as soon as the pressure build-up was initiated. In the next 50 minutes, the 206 pressure and temperature were stabilized around 27.5 MPa (4000 psi) and 40 °C (104 °F), 207 respectively. Fluid expulsion continued during this period but with much lower amplitude 208 209 (0.001 ml/min). Then the pressure and temperature were raised to 38 MPa (5511 psi) and 60 °C (140 °F), respectively. The sudden increase of pressure caused a fluid expulsion jump 210 211 of 0.03 ml/min. Followed by approximately 950 minutes of relatively steady pressure with 212 subtle fluctuations. Fluid expulsion during this period was relatively stable around less than 213 0.001 ml/min, but several peaks can be observed and correlated with the relatively obvious 214 changes in the pressure.

215 ② The first unloading stage

The first unloading stage was initiated at 1000 minutes. The confining pressure

217 rapidly dropped to about 0.1 MPa (14.5 psi) and correspondingly the temperature was adjusted to 25 °C (77 °F). The sharp decline of pressure introduced high picks of fluid 218 expulsion. The fluid expulsion did not cease during the first unloading stage. In this stage, the 219 220 matrix grain compressibility makes the matrix grain expand and expel the fluid. The fluid near the outlet is expelled instantly, and then the fluid away from the outlet is squeezed to the 221 outlet and expelled gradually. Fluid expansion is considered, while the value is much smaller 222 223 than that of the matrix grain expansion. Matrix grain expansion is the major mechanism 224 determining the porosity change in this stage.

225 ③ The second loading stage

The second loading stage followed the first unloading stage. It was started by a gentle 226 increase of confining pressure from 0.45 MPa to 1.45 MPa (65-210 psi) in 30 minutes. Fluid 227 expulsion along with this gentle increase is subtle. Then the confining pressure was rapidly 228 increased reaching 34 MPa (4930 psi) in 32 minutes. Fluid expulsion in this time interval 229 exhibited significant increase and the highest instantaneous expulsion reached 4 ml/min at the 230 starting point of rapid pressure increase. 231

④ The second unloading stage 232

The last procedure of the experiment was reducing the confining pressure to zero in 233 15 minutes. Fluid expulsion did not take place in the first ten minutes of this stage, but it 234 235 happened afterwards. With the pressure stabilized to zero the fluid expulsion ceased.

236

4.2 Implications of the experimental results

237 The four stages in the experiment represent the different situations and processes the 238 sandstones experienced: in-situ (the first loading – stabilizing stage), coring and lifting (the 239 first unloading stage), lab porosity test under elevated confining pressure (the second loading stage), and the unloading after the test. The fluid expulsion is converted to porosity and 240 241 correlated with the effective stress (Figure 4). The porosity had been stable and dropped only 0.6% during the fast loading and long-time stabilizing of the first loading stage, indicating the porosity is stable under constant compaction. The porosity kept decreasing mildly in the first unloading stage but the porosity loss was 1.6%, which is more obvious than the first loading stage, indicating the porosity loss during coring and lifting is not negligible. The porosity dropped sharply (3.5%) during the second loading stage, suggesting the conventional porosity test under elevated confining pressure damages the porosity significantly. The porosity loss in the second unloading stage proves the porosity damage is permanent.

249 **5. Discussion**

A model of porosity changes is established based on the theoretical analysis and 250 experimental results (Figure 5). The nature of the porosity change is the combination of the 251 changes of the matrix volume, grain contact, and cement relocation; it is the result of the 252 external (confining pressure) and internal (pore pressure) forces. Rocks, as porous media, 253 demonstrate three types of deformations: elastic, plastic, and elastic-plastic deformations 254 (Hueckel and Maier., 1977; Mühlhaus, 2014; Grgic, 2016). Both elastic and plastic 255 deformations take place in the loading stages (1) and (3). While in the unloading stages (2)256 and (4), a portion of elastic deformation recovers and the matrix grains expand. 257 Theoretically the expansion of matrix grains can be in any direction, both to the exterior and 258 to the interior, i.e. the pore spaces. However, the area of the exterior surface of a rock is 259 260 smaller than the internal surface area (the total surface of the pores), making it easier for the 261 matrix grains to expand into pore spaces. In addition, in our experiment the core is confined 262 in the vessel leaving no room for the core to expand toward its outside. Thus, the matrix 263 grains expand dominantly towards pore spaces. The pores are compressed and porosity is 264 reduced. The analysis is consistent with the theoretical deduction and experimental results, 265 which all lead to the conclusion that the porosity measured in conventional core analysis is less than that of the *in-situ* reservoir. Referring to our experimental results, for normally 266

compacted sandstones, when the *in-situ* confining pressure is approximately 30~35 MPa
(4350-5076 psi), the coring and lifting would cause a porosity reduction of approximately
1.2%~1.6%. In this case, the porosity measurements at elevated confining stress deviate from
the original porosity, thus it cannot represent the in-situ porosity without adding a proper
porosity loss.

It has been suggested qualitatively that measurements at elevated confining stress 272 273 more closely represent original reservoir porosity than measurements at zero or low confining 274 stress. Our theoretical and experimental analyses indicate that porosity loss is irreversible whether the confining pressure is released or elevated. Furthermore, as physical processes act 275 276 upon the core (e.g. loading or unloading) a decline in porosity will occur. Consequently, the measurement under ambient conditions shortly after coring and lifting is the best measure for 277 reservoir porosity. Temperature is also a factor in porosity changes, however within the 278 temperature range in our experiments (25~60 °C, i.e. 77~140 °F), the effect of temperature is 279 not significant. Things may be more complicated at the higher temperatures and greater 280 temperature differences, and the issue of temperature would need additional analysis. 281

282 **6.** Conclusion

Theoretical deductions of the changes and relationships of pressure, volume, and 283 284 compressibility suggest porosities of reservoir rocks are greater at depth than at the surface 285 due to porosity reduction during the coring and lifting process. The experiment of repeated loading and unloading of a sandstone sample quantitatively validated the theoretical analysis. 286 287 When the *in-situ* confining pressure is approximately 30~35 MPa (4350-5076 psi), the coring 288 and lifting would cause a porosity reduction of approximately 1.2%~1.6%. The original 289 reservoir porosity should be the laboratory measured data at ambient pressure plus 290 1.2%~1.6%. The porosity measurement at elevated confining pressure suffers from more 291 porosity loss and should not be used to represent the reservoir porosity. The re-consideration of in-situ reservoir porosity by this approach demonstrates significant implications forreservoir recovery factors and reserve calculations.

294	Nomenclatures
295	V _b : the bulk volume of rock
296	V _p : the total volume of pores of rock
297	V_r : the volume of rock matrix
298	c_b : the bulk compressibility of rock
299	<i>c_r</i> : the compressibility of rock matrix
300	c_P : the compressibility of pores
301	σ : the overburden pressure (confining pressure)
302	<i>P</i> : the pore pressure
303	ϕ : porosity
304	Conversions for units of measurements
305	1 cm = 0.394 in
306	1 m = 3.281 ft
307	1 ml = 0.034 oz
308	1 MPa =145.038 psi
309	°C=(°F-32)/1.8
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448 **Figure and table captions:**

449 Figure 1. Schematic drawing of the experimental apparatus.

- Figure 2. Photographs of the core made in this study: a. the overall image of the core which is 13 cm (5.12 inch) in diameter and 17 cm (6.7 inch) in length; b. the composition of the core under microscope, in this image the proportions of grain matrix (mainly consists of 0.13-0.50 mm quarts, feldspar, and debris), cements (clay minerals and calcite), and pores are 81%, 5%, and 14%, respectively.
- 455 Figure 3. The details of confining pressure, temperature, and fluid expulsion in the 456 experiment. ① the first loading-stabilizing stage; ② The first unloading stage; ③

457 The second loading stage; ④ The second unloading stage.

- 458 Figure 4. The correlations of porosity and effective stress in the order of experimental time.
- 459 ① The first loading-stabilizing stage (the in-situ status); ② The first unloading

460 stage (coring and lifting); ③ The second loading stage (porosity test under high

461 confining pressure); ④ The second unloading stage.

- 462 Figure 5. The porosity and density of reservoir rocks in different processes.
- 463 (1) compaction; (2) coring and lifting; (3) lab porosity test under high confining
- 464 pressure; ④ unloading in lab test.

465 Table 1. The experiment data of pressure, temperature, and fluid expulsion.

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time (min)	inlet pressure (MPa)	outlet pressure (MPa)	confining pressure (MPa)	temperature (°C)	averaged fluid expulsion rate (ml/min)		
10	32.81	0.04	32.77	50.20	0.003		
93	38.27	0.04	38.23	60.05	0.002		
206	37.24	0.04	37.20	60.05	0.001		
323	36.17	0.04	36.13	60.00	0.001		
434	36.08	0.04	36.04	60.00	0.001		
529	35.95	0.03	35.92	60.00	0.001		
636	35.61	0.04	35.58	60.10	0.001		
747	35.75	0.03	35.72	62.55	0.003		
848	36.79	0.03	36.76	64.95	0.003		
936	37.32	0.03	37.29	65.05	0.002		
949	37.36	0.03	37.33	64.95	0.002		
960	37.38	0.03	37.35	64.95	0.002		
976	37.39	0.03	37.36	64.95	0.003		
990	37.38	0.04	37.35	64.95	0.011		
1004	28.89	0.03	28.86	64.85	0.007		
1017	10.45	0.04	10.42	55.65	0.022		
1028	0.39	0.04	0.35	45.35	0.408		
1113	0.28	0.03	0.25	29.40	1.059		
1120	0.56	0.04	0.52	33.15	0.031		
1129	1.72	0.04	1.69	38.30	0.050		
1138	1.98	0.03	1.95	39.45	1.000		
1146	1.99	0.03	1.96	40.20	0.087		
1153	3.00	0.03	2.97	40.60	0.007		
1161	12.24	0.03	12.21	39.50	0.005		
1177	29.66	0.03	29.63	38.40	0.032		
1184	17.25	0.04	17.22	34.35	1.396		
1194	0.04	0.03	0.01	30.00	0.009		